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

Form 10-Q

(Mark One)

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

For the quarterly period ended September 30, 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 November 12, 2002: 598,964,891

PART I — FINANCIAL INFORMATION

Item 1. Financial Statements

EL PASO CORPORATION

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

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
Operating revenues	$2,656	$3,166	$ 9,398	$10,890
Operating expenses				
Cost of products and services	1,396	1,381	4,481	5,269
Operation and maintenance	645	724	1,891	2,196
Restructuring and merger-related costs and asset impairments	—	32	405	1,792
Ceiling test charges	—	135	267	135
Depreciation, depletion and amortization	340	338	1,057	982
Taxes, other than income taxes	64	77	212	291
	2,445	2,687	8,313	10,665
Operating income	211	479	1,085	225
Earnings from unconsolidated affiliates	105	102	296	302
Minority interest in consolidated subsidiaries	1	(1)	(55)	(1)
Net gain (loss) on sale of assets	(32)	4	(1)	16
Other income	67	75	253	229
Other expenses	(19)	(11)	(121)	(39)
Interest and debt expense	(342)	(280)	(1,008)	(866)
Returns on preferred interests of consolidated subsidiaries	(38)	(51)	(121)	(169)
Income (loss) before income taxes	(47)	317	328	(303)
Income taxes	(14)	102	105	4
Income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	(33)	215	223	(307)
Discontinued operations, net of income taxes	(36)	1	(122)	(1)
Extraordinary items, net of income taxes	—	(5)	—	26
Cumulative effect of accounting changes, net of income taxes	—	—	168	—
Net income (loss)	$ (69)	$ 211	$ 269	$ (282)
Basic earnings per common share				
Income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	$(0.06)	$ 0.43	$ 0.41	$ (0.61)
Discontinued operations, net of income taxes	(0.06)	—	(0.22)	—
Extraordinary items, net of income taxes	—	(0.01)	—	0.05
Cumulative effect of accounting changes, net of income taxes	—	—	0.30	—
Net income (loss)	$(0.12)	$ 0.42	$ 0.49	$ (0.56)
Diluted earnings per common share				
Income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	$(0.06)	$ 0.42	$ 0.41	$ (0.61)
Discontinued operations, net of income taxes	(0.06)	—	(0.22)	—
Extraordinary items, net of income taxes	—	(0.01)	—	0.05
Cumulative effect of accounting changes, net of income taxes	—	—	0.30	—
Net income (loss)	$(0.12)	$ 0.41	$ 0.49	$ (0.56)
Basic average common shares outstanding	586	506	548	504
Diluted average common shares outstanding	586	520	549	504
Dividends declared per common share	$ 0.22	$ 0.21	$ 0.65	$ 0.64

See accompanying notes.

EL PASO CORPORATION

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

	September 30, 2002	December 31, 2001
Current assets		
Cash and cash equivalents	$ 1,693	$ 1,148
Accounts and notes receivable, net		
Customer	5,139	5,040
Unconsolidated affiliates	1,175	911
Other	1,132	895
Inventory	828	815
Assets from price risk management activities	1,450	2,702
Other	2,002	1,118
Total current assets	13,419	12,629
Property, plant and equipment, at cost		
Pipelines	17,837	17,596
Natural gas and oil properties, at full cost	14,277	14,466
Refining, crude oil and chemical facilities	2,505	2,425
Gathering and processing systems	1,100	2,628
Power facilities	1,093	834
Other	614	565
	37,426	38,514
Less accumulated depreciation, depletion and amortization	13,785	14,224
Total property, plant and equipment, net	23,641	24,290
Other assets		
Investments in unconsolidated affiliates	4,967	5,297
Assets from price risk management activities	3,270	2,118
Intangible assets, net	1,434	1,442
Other	2,375	2,395
	12,046	11,252
Total assets	$49,106	$48,171

See accompanying notes.

EL PASO CORPORATION

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

	September 30, 2002	December 31, 2001
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 5,662	$ 4,944
Unconsolidated affiliates	42	26
Other	605	959
Short-term borrowings and other financing obligations	938	3,314
Notes payable to unconsolidated affiliates	174	504
Liabilities from price risk management activities	1,462	1,868
Other	1,604	1,950
Total current liabilities	10,487	13,565
Debt		
Long-term debt and other financing obligations	16,250	12,816
Notes payable to unconsolidated affiliates	199	368
	16,449	13,184
Other liabilities		
Liabilities from price risk management activities	1,695	1,231
Deferred income taxes	4,497	4,459
Other	2,014	2,363
	8,206	8,053
Commitments and contingencies		
Securities of subsidiaries		
Preferred interests of consolidated subsidiaries	3,605	3,955
Minority interests in consolidated subsidiaries	123	58
	3,728	4,013
Stockholders' equity		
Common stock, par value $3 per share; authorized 1,500,000,000 shares and issued 604,977,289 shares in 2002; authorized 750,000,000 shares and issued 538,363,664 shares in 2001	1,815	1,615
Additional paid-in capital	4,387	3,130
Retained earnings	4,811	4,902
Accumulated other comprehensive income (loss)	(409)	157
Treasury stock (at cost) 7,348,471 shares in 2002 and 7,628,799 shares in 2001	(250)	(261)
Unamortized compensation	(118)	(187)
Total stockholders' equity	10,236	9,356
Total liabilities and stockholders' equity	$49,106	$48,171

See accompanying notes.

EL PASO CORPORATION

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

	Nine Months Ended September 30, 2002	Nine Months Ended September 30, 2001
Cash flows from operating activities		
Net income (loss)	$ 269	$ (282)
Less loss from discontinued operations, net of income taxes	(122)	(1)
Net income (loss) from continuing operations	391	(281)
Adjustments to reconcile net income (loss) to net cash from operating activities		
Non-cash gains from trading and power activities	(507)	(196)
Non-cash portion of merger-related costs, asset impairments and changes in estimates	342	1,585
Depreciation, depletion and amortization	1,057	982
Ceiling test charges	267	135
Undistributed earnings of unconsolidated affiliates	(112)	(77)
Deferred income tax expense (benefit)	102	(10)
Extraordinary items	—	(53)
Cumulative effect of accounting changes	(177)	—
Other non-cash income items	142	94
Working capital changes	(51)	1,636
Non-working capital changes and other	(393)	(335)
Cash provided by continuing operations	1,061	3,480
Cash provided by (used in) discontinued operations	98	(4)
Net cash provided by operating activities	1,159	3,476
Cash flows from investing activities		
Additions to property, plant and equipment	(2,608)	(2,764)
Additions to investments	(856)	(1,290)
Net proceeds from the sale of assets	1,453	384
Net proceeds from investments	154	266
Cash deposited in escrow	(203)	—
Return of cash deposited in escrow	117	—
Repayment of notes receivable from unconsolidated affiliates	514	253
Cash paid for acquisitions, net of cash acquired	45	(232)
Other	11	—
Cash used in continuing operations	(1,373)	(3,383)
Cash used in discontinued operations	(10)	(35)
Net cash used in investing activities	(1,383)	(3,418)
Cash flows from financing activities		
Net repayments under commercial paper and short-term credit facilities	(1,087)	(511)
Repayments of notes payable	(109)	(2)
Payments to retire long-term debt and other financing obligations	(2,038)	(1,856)
Proceeds from the issuance of minority interest	33	—
Net proceeds from the issuance of long-term debt and other financing obligations	4,287	3,021
Payments to minority interest holders	(161)	—
Payments to preferred interest holders	(350)	—
Issuances of common stock	1,051	46
Dividends paid	(340)	(278)
Increase in notes payable to unconsolidated affiliates	4	37
Decrease in notes payable to unconsolidated affiliates	(511)	(479)
Contributions from (distributions to) discontinued operations	78	(47)
Cash provided by (used in) continuing operations	857	(69)
Cash provided by (used in) discontinued operations	(78)	47
Net cash provided by (used in) financing activities	779	(22)
Increase in cash and cash equivalents	555	36
Less increase in cash and cash equivalents related to discontinued operations	10	8
Increase in cash and cash equivalents from continuing operations	545	28
Cash and cash equivalents		
Beginning of period	1,148	745
End of period	$ 1,693	$ 773

See accompanying notes.

EL PASO CORPORATION

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

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2002	**2001**	**2002**	**2001**
Net income (loss)	$ (69)	$211	$ 269	$ (282)
Foreign currency translation adjustments	(30)	—	(3)	—
Unrealized net gains (losses) from cash flow hedging activity				
Cumulative-effect transition adjustment (net of tax of $673)	—	—	—	(1,280)
Unrealized mark-to-market gains (losses) arising during period (net of tax of $23 and $237 in 2002, and $260 and $587 in 2001)	(53)	462	(399)	1,114
Reclassification adjustments for changes in initial value to settlement date (net of tax of $3 and $86 in 2002, and $46 and $338 in 2001)	5	(86)	(164)	596
Other	—	(4)	—	(22)
Other comprehensive income (loss)	(78)	372	(566)	408
Comprehensive income (loss)	$(147)	$583	$(297)	$ 126

See accompanying notes.

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 2001 Annual Report on Form 10-K which includes a summary of our significant accounting policies and other disclosures. The financial statements as of September 30, 2002, and for the quarters and nine months ended September 30, 2002 and 2001, are unaudited. We derived the balance sheet as of December 31, 2001, from the audited balance sheet filed in our Form 10-K. In our opinion, we have made all adjustments, all of which are of a normal, recurring nature (except for the items discussed below and in Notes 4 through 8), 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. 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.

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

Goodwill and Other Intangible Assets

Our intangible assets consist of goodwill resulting from acquisitions and other intangible assets. 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 intangibles that have lives that are indefinite are no longer amortized. Rather, goodwill is periodically tested for impairment, at least on an annual basis, or whenever an event occurs that indicates that an impairment may have occurred. SFAS No. 141 requires that any negative goodwill should be written-off as a cumulative effect of an accounting change. Prior to adoption of these standards, we amortized 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 stopped amortizing goodwill. We also recognized a pretax and after-tax gain of $154 million related to the elimination of negative goodwill. We have reported this gain as a cumulative effect of an accounting change in our income statement.

We completed our initial periodic impairment tests of goodwill during the first quarter of 2002, and concluded we did not have any adjustment to our goodwill amounts. The net carrying amounts and changes in the net carrying amounts of goodwill for each of our segments for the nine month period ended September 30, 2002, are as follows:

	Pipelines	Production	Merchant Energy	Field Services	Corporate & Other	Total
			(In millions)			
Balances as of January 1, 2002	$408	$61	$89	$393	$254	$1,205
Purchase price adjustments	—	—	—	14	—	14
Other changes	—	1	—	—	(6)	(5)
Balances as of September 30, 2002	$408	$62	$89	$407	$248	$1,214

Our other intangible assets consist of capitalized development costs, software licensing agreements, customer lists, our general partnership interest in El Paso Energy Partners, L.P., and other miscellaneous intangible assets. We amortize all intangible assets on a straight-line basis over their estimated useful life excluding our general partnership interest in El Paso Energy Partners which has been determined to have an indefinite life. El Paso Energy Partners is a publicly traded master limited partnership of which our subsidiary serves as the general partner. See Note 16 for a further discussion of our relationships with the partnership.

The following are the gross carrying amounts and accumulated amortization of our other intangible assets as of:

	September 30, 2002	December 31, 2001
	(In millions)	
Intangible assets subject to amortization	$ 82	$ 86
Accumulated amortization	(44)	(31)
	38	55
Intangible assets not subject to amortization	182	182
	$220	$237

Amortization expense of our intangible assets that were subject to amortization was $4 million and $16 million for the quarter and nine months ended September 30, 2002. For the quarter and nine months ended September 30, 2001, amortization of all intangible assets, including goodwill, was $14 million and $38 million. Based on the current amount of intangible assets subject to amortization, our estimated amortization expense is $6 million for each of the next five years. These amounts may vary as a result of future acquisitions and dispositions.

The following table presents our income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes, net income (loss) and earnings per common share for the quarter and nine months ended September 30, 2001, as if goodwill and other indefinite-lived intangibles had not been amortized during those periods, compared with the income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes, net income (loss) and earnings per common share we reported for the quarter and nine months ended September 30, 2002:

	Quarter Ended September 30,		Nine months Ended September 30,	
	2002	2001	2002	2001
	(In millions, except per common share amounts)			
Reported income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	$ (33)	$ 215	$ 223	$ (307)
Amortization of goodwill and indefinite-lived intangibles	—	8	—	23
Adjusted income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	$ (33)	$ 223	$ 223	$ (284)
Net income (loss):				
Reported net income (loss)	$ (69)	$ 211	$ 269	$ (282)
Amortization of goodwill and indefinite-lived intangibles	—	8	—	23
Adjusted net income (loss)	$ (69)	$ 219	$ 269	$ (259)
Basic earnings per common share:				
Reported net income (loss)	$(0.12)	$0.42	$0.49	$(0.56)
Amortization of goodwill and indefinite-lived intangibles	—	0.02	—	0.05
Adjusted net income (loss)	$(0.12)	$0.44	$0.49	$(0.51)
Diluted earnings per common share:				
Reported net income (loss)	$(0.12)	$0.41	$0.49	$(0.56)
Amortization of goodwill and indefinite-lived intangibles	—	0.01	—	0.05
Adjusted net income (loss)	$(0.12)	$0.42	$0.49	$(0.51)

Asset Impairments

On January 1, 2002, we adopted SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. SFAS No. 144 changed the accounting requirements related to when an asset qualifies as held for sale or as a discontinued operation and the way in which we evaluate impairments of assets. It also changes accounting for discontinued operations such that we can no longer accrue future estimated operating losses in these operations. We applied SFAS No. 144 in accounting for our coal mining operations and the proposed sale of our San Juan assets. Our coal mining business was treated as discontinued operations in the second quarter of 2002, and the San Juan assets were treated as assets held for sale in the third quarter of 2002. See Notes 2 and 7 for further information.

Early Extinguishment of Debt

During the third quarter of 2002, we adopted the provisions of SFAS No. 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections*. SFAS No. 145 requires that we evaluate any gains or losses incurred when we retire debt early to determine whether they are extraordinary in nature or whether they should be included in income from continuing operations in the income statement. In the third quarter of 2002, we retired debt totaling $94 million, which resulted in a gain of $21 million. Because we believe that we will continue to retire debt in the near term, we reported these gains as income from continuing operations, as part of other income.

Price Risk Management Activities

In the second quarter of 2002, we adopted Derivatives Implementation Group (DIG) Issue No. C-15, *Scope Exceptions: Normal Purchases and Sales Exception for Certain Option-Type Contracts and Forward Contracts in Electricity*. DIG Issue No. C-15 requires that if an electric power contract includes terms that are based upon market factors that are not related to the actual costs to generate the power, the contract is a derivative that must be recorded at its fair value. An example is a power sales contract at a natural gas-fired power plant that has pricing indexed to the price of coal. Our adoption of these rules did not have a material effect on our financial statements. The accounting for electric power contracts as derivatives was not clearly addressed when SFAS No. 133, *Accounting for Derivatives and Hedging Activities*, was adopted in January 2001. DIG Issue No. C-15 and other DIG Issues have attempted to resolve inconsistencies in the accounting for power contracts, and we believe the rules will continue to evolve. It is possible that our accounting for these contracts may change as new guidance is issued and existing rules are applied and interpreted.

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*. DIG Issue No. C-16 requires that if a fixed-price fuel supply contract allows the buyer to purchase, at their option, additional quantities at a fixed price, the contract is a derivative that must be recorded at its fair value. One of our unconsolidated affiliates, the Midland Cogeneration Venture Limited Partnership, recognized a gain on one fuel supply contract upon adoption of these new rules, 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.

During the second quarter of 2002, we adopted a consensus decision reached by the Emerging Issues Task Force (EITF) in EITF Issue No. 02-3, *Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities.* The consensus required that all mark-to-market gains and losses related to energy trading contracts, including physical settlements, be recorded on a net basis in the income statement instead of being reported on a gross basis as revenues for physically settled sales and expenses for physically settled purchases. As a result of adoption, we now report our trading activity on a net basis as a component of revenues. We also applied this guidance to all prior periods, which had no impact on previously reported net income or stockholders' equity. For the quarter and nine months ended September 30, 2001, we reclassified costs of $10.6 billion and $34.3 billion to operating revenues. In October 2002, the EITF reached several additional decisions regarding accounting for energy trading contracts. See Note 18 for a discussion of these decisions.

Accounting for Power Restructuring Activities. Our Merchant Energy segment's power restructuring activities involve amending or terminating a power plant's existing power purchase contract to eliminate the requirement that the plant provide power from its own generation to the regulated utility and replacing that requirement with the ability to provide power to the utility from the wholesale power market. Prior to a restructuring, the power plant and its related power purchase contract are generally accounted for at their historical cost, which is either the cost of construction or, if acquired, the acquisition cost. Revenues and expenses prior to restructuring are, in most cases, accounted for on an accrual basis as power is generated and sold to the utility. Following a restructuring, the accounting treatment for the power purchase agreement can change if the restructured contract meets the definition of a derivative and is therefore required to be marked to its fair value under SFAS No. 133. In the period the restructuring is completed, the book value of the restructured contract (if it meets the definition of a derivative) is adjusted to its fair value, with any change reflected in income. Since the power plant no longer has the exclusive right to provide power under the original, dedicated power purchase contract, it operates as a peaking merchant plant, generating power only when it is economical to do so. Because of this significant change in its use, in most cases the book value of the plant is reduced to its fair value through a charge to earnings. These changes require us to terminate or amend any related fuel supply and steam agreements associated with the operations of the facility.

We conduct the majority of our power restructuring activities through our unconsolidated affiliate, Chaparral, and therefore our share of the revenues and expenses of these activities is recognized through earnings from unconsolidated affiliates. However, as in the case of the Eagle Point Cogeneration restructuring completed in the first quarter of 2002, we also conduct these activities for power assets owned by our consolidated subsidiaries. In consolidated entities, the restructured power contract is presented in our balance sheet as an asset from price risk management activities. In our income statement we present, as operating revenues, the original adjustment that occurs when the contract is marked to fair value as a derivative, as well as subsequent changes in the value of the contract. Costs associated with the restructuring activity, including adjustments to the underlying power plant's book value and any related intangible assets, contract termination fees and closing costs, are recorded in our income statement as cost of products and services. Power restructuring activities can also involve contract terminations that result in a cash payment by the utility to cancel the underlying power contract, such as in our Mount Carmel transaction. We also employed the principles of our power restructuring business in reaching a settlement in the first quarter of 2002 of the dispute under our Nejapa power contract which included a cash payment to us. We recorded these payments as operating revenues. For the nine months ended September 30, 2002, we recognized total revenues from power restructuring and contract termination activities of $1,160 million and total costs of $594 million. On the date the restructuring transactions were completed, revenues recorded were $1,103 million and costs were $539 million. Revenues and costs recorded after the initial completion date, which consisted of changes in value of the restructured contracts and those associated with performing under the contracts, were $57 million and $55 million.

2. Divestitures

In December 2001, we announced a plan to strengthen our balance sheet in order to improve our liquidity in response to changes in market conditions in our industry. A key component of that plan was the identification and sale of assets. Through the date of this report, we have completed or announced the following asset sales:

Completed Asset Sales

Disposal Period	Disposed Asset	Net Proceeds (In millions)	Gain	Segment
March 2002	Natural gas and oil properties located in east and south Texas	$512	—[1]	Production
April 2002	Texas and New Mexico midstream assets	$735[2]	—	Field Services
May 2002	Dragon Trail processing plant	$ 65	$10	Field Services
May 2002	Natural gas and oil properties located in Colorado	$212	—[1]	Production
June 2002	Natural gas and oil properties located in southeast Texas	$ 48	—[1]	Production
July 2002	Natural gas and oil production properties in Texas, Kansas and Oklahoma and their related contracts	$112	—[1]	Pipelines
September 2002	50 percent equity interest in a petroleum products terminal	$ 31	$15	Merchant Energy

[1] We did not recognize gains or losses on the natural gas and oil production properties sold since they were not significant in terms of the total costs or reserves in our full cost pool of properties.

[2] Proceeds of $735 million consisted of $539 million in cash, 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.

Announced Asset Sales

We have announced the sale of additional assets to third parties, including:

Assets to be Disposed	Sales Price (In millions)	Segment	Estimated Completion Date
San Juan assets • San Juan Basin gathering, treating and processing assets • Typhoon natural gas and oil pipelines • Natural gas liquids (NGL) pipelines and fractionation facilities	$782	Pipelines, Merchant Energy and Field Services	4th quarter 2002
Panhandle gathering system	$ 19	Pipelines	4th quarter 2002 or 1st quarter 2003
Alliance Pipeline investment • 14.4 percent interest in Alliance Pipeline and related assets • 14.4 percent interest in Alliance Canada Marketing L.P. • 14.4 percent interest in Aux Sable NGL plant	$165	Pipelines, Merchant Energy and Field Services	1st quarter 2003
Natural gas and oil properties and gathering facilities located in Utah	$502	Production and Field Services	4th quarter 2002
Coal assets in West Virginia, Virginia and Kentucky	$ 69	—[1]	4th quarter 2002
Snøhvit liquefied natural gas (LNG) supply contract and assignment of Cove Point capacity contract	$210	Merchant Energy	4th quarter 2002

[1] These properties are in our financial statements as discontinued operations. See Note 7 for further discussion.

The proposed San Juan asset sale was approved by both our and El Paso Energy Partners' Boards of Directors, which included the approval of El Paso Energy Partners' special conflicts committee, which is comprised of independent members of the partnership's Board of Directors. In addition, we received a fairness opinion from Deutsche Bank stating that the proceeds to be received from El Paso Energy Partners for all of the assets being sold was fair in relation to the value of the related assets. This transaction is subject to customary regulatory reviews and approvals, as well as the execution of definitive agreements, the completion of due diligence and the partnership's ability to successfully obtain financing for the transaction. The proposed sale contemplates that we will receive up to $350 million of the El Paso Energy Partners' Series C units, a new non-voting class of the partnership's limited partner interest, with the balance of the consideration to be received in cash. The potential $350 million amount will be reduced by the proceeds from any sale of limited partnership interests by El Paso Energy Partners before the closing of the San Juan asset sale. The Series C units will be issued at the greater of $32 per unit or the average market price for the five trading days ending on the business day immediately preceding the closing date. If the average market price of the units is less than $27, the San Juan asset sale may be delayed, terminated or renegotiated.

The San Juan assets have been classified as assets held for sale in our balance sheet as of September 30, 2002, and we stopped depreciating these assets beginning July 2002. The total assets being sold include net property, plant and equipment and other assets of approximately $442 million. We reclassified these assets as other current assets as of September 30, 2002, since we plan to sell them in the next twelve months. Based upon our anticipated proceeds, we expect to realize a gain from this sale of approximately $262 million.

The sale of our federally regulated natural gas gathering system located in the Panhandle Field of Texas is subject to final closing pending a FERC abandonment order.

The sale of our investments in the Alliance Pipeline and Aux Sable natural gas liquids plant is subject to customary regulatory reviews and approvals and the execution of definitive agreements. Based on the estimated sales price, we recorded a loss for the quarter ended September 30, 2002, of approximately $47 million. The loss relates to our investment in Aux Sable and is included in our Field Services segment.

Our other announced sales are subject to customary regulatory reviews and approvals.

3. Announced Exit of Energy Trading Activities

On November 8, 2002, we announced our plan to exit the energy trading business. Our primary plan includes forming a new wholly owned subsidiary to separately hold, manage and liquidate our trading assets and liabilities in an orderly manner over a period of eighteen to twenty-four months. Additionally, in October, new accounting guidance was issued which disallows the use of mark-to-market accounting for energy-related contracts that do not qualify as derivatives under SFAS No. 133. We are in the initial stage of evaluating the impact of our decision to exit the energy trading business and adopting the new accounting rules; however, we expect the carrying value of our trading assets and liabilities, as shown on our balance sheet as of September 30, 2002, will be written down substantially. At this time, we estimate that these events will result in an after-tax charge of approximately $400 million to $600 million ($600 million to $900 million before tax). We expect to adopt the new accounting rules and implement the exit strategy in the fourth quarter of 2002. For a further discussion of our exit plan, see Item 2, Management's Discussion and Analysis of Financial Condition, under the subheading Merchant Energy. The new accounting guidance is further discussed in Note 18, New Accounting Pronouncements Not Yet Adopted.

4. Restructuring and Merger-Related Costs and Asset Impairments

The following tables summarize our organizational restructuring and merger-related costs and asset impairments for the periods ended September 30:

	Nine Months Ended September 30, 2002					
	Pipelines	Production	Merchant Energy	Field Services	Corp. and Other	Total
			(In millions)			
Restructuring costs						
Employee severance, retention and transition costs	$ 1	$ —	$ 11	$ 1	$ 10	$ 23
Transaction costs	—	—	—	—	40	40
Asset impairments	—	—	342	—	—	342
Total restructuring costs and asset impairments	$ 1	$ —	$353	$ 1	$ 50	$ 405

	Quarter Ended September 30, 2001					
	Pipelines	Production	Merchant Energy	Field Services	Corp. and Other	Total
			(In millions)			
Merger-related costs						
Employee severance, retention and transition costs	$ (4)	$ —	$ —	$—	$ 14	$ 10
Transaction costs	—	—	—	—	3	3
Business and operational integration costs	1	—	—	—	—	1
Merger-related asset impairments	4	—	—	—	—	4
Other	—	—	—	9	5	14
Total merger-related costs	$ 1	$ —	$ —	$ 9	$ 22	$ 32

	Nine Months Ended September 30, 2001					
	Pipelines	Production	Merchant Energy	Field Services	Corp. and Other	Total
			(In millions)			
Merger-related costs						
Employee severance, retention and transition costs	$ 83	$ 7	$ 18	$ 5	$ 716	$ 829
Transaction costs	—	—	—	—	70	70
Business and operational integration costs	187	17	—	—	220	424
Merger-related asset impairments	16	16	116	—	1	149
Other	30	23	10	41	109	213
Asset impairments	—	—	47	—	60	107
Total merger-related costs and asset impairments	$316	$ 63	$191	$46	$1,176	$1,792

Restructuring Costs

In December 2001, we announced a plan to strengthen our balance sheet, reduce costs and focus our activities on our core natural gas businesses. During the second quarter of 2002, we incurred $63 million of costs related to these efforts. In the second and third quarters of 2002, we completed an employee restructuring across all of our operating segments which resulted in a reduction of approximately 509 full-time positions through terminations. Through September 30, 2002, we had incurred and paid $23 million of employee severance and termination costs in connection with these actions. We also incurred fees of $40 million to eliminate stock price and credit rating triggers related to our Chaparral and Gemstone investments. This amount was paid in the second quarter of 2002. See Note 16 for further information on the Chaparral and Gemstone amendments.

Merger-Related Costs

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 our merger with The Coastal Corporation (Coastal), 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 these restructurings. Retention charges include payments to employees who were retained following the mergers 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.

Employee severance, retention, and transition costs for the nine months ended September 30, 2001, were approximately $829 million which include pension and post-retirement benefits of $214 million which were accrued at the merger date and will be paid over the applicable benefit periods of the terminated and retired employees. All other costs were expensed as incurred and have been paid. Also included in the 2001 employee severance, retention and transition costs was a charge of $278 million resulting from the issuance of approximately 4 million shares of common stock on the date of the Coastal merger in exchange for the fair value of Coastal employees' and directors' stock options and restricted stock. A total of 339 employees and 11 directors received these shares.

Transaction costs for the nine months ended September 30, 2001, were $70 million which 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 mergers. All of these items were expensed in the periods in which they were incurred.

Business and operational integration costs include charges to consolidate facilities and operations of our business segments. Total charges for the nine months ended September 30, 2001, were $424 million, of which $153 million related to a charge resulting from a mark-to-market loss on an energy-related contract for transportation capacity on the Alliance Pipeline. Prior to the merger, this contract was managed by Coastal's Production segment. Following the merger, it was determined that this contract should be managed by our trading group, consistent with our energy-related pipeline capacity contracts. As a result, it was transferred to Merchant Energy. The charge reflects the estimated realizable value of the contract as an energy-related trading contract. Our integration costs also include incremental fees under software and seismic license agreements of $15 million, which were recorded in our Production segment, and approximately $250 million in estimated lease-related costs to relocate our pipeline operations from Detroit, Michigan to Houston, Texas and from El Paso, Texas to Colorado Springs, Colorado incurred in both our Pipelines and Corporate segments. 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 agreements. All other costs were expensed as incurred.

Merger-related asset impairments for the nine months ended September 30, 2001, were $149 million which relate to write-offs or write-downs of capitalized costs for duplicate systems, redundant 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. Our Merchant Energy segment incurred $116 million in asset impairment charges primarily related to the write-down of $37 million for the Oyster Creek refining facility which was shut down following the merger, $35 million for the Kansas refinery which was closed as part of the sale of retail outlets in the Midwest, $20 million for capitalized development costs primarily associated with our petroleum operations and $24 million for other assets. Included in our Production segment was a $16 million charge to write-down Australian and Indonesian international assets since the decision was made following the merger to no longer actively seek future exploratory drilling opportunities in these areas. Additional charges of $16 million were incurred in the Pipelines segment primarily to write-off investments in the Whitecap and the Supply Link projects, both of which were pipeline projects discontinued following the merger. 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 our changes in operating strategy.

Other costs for the nine months ended September 30, 2001, were $213 million which include payments made in satisfaction of obligations arising from the approval of our merger with Coastal and other miscellaneous charges. These items were expensed in the period in which they were incurred.

Asset Impairments

During the first quarter of 2002, we recognized an asset impairment charge in our Merchant Energy segment of $342 million related to 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 $39 million. Should these conditions persist, or if new unfavorable developments occur, we may also be required to evaluate our remaining investment for impairment. We continue to monitor the situation closely, including our rights and remedies under applicable law, treaties and political risk policies arising from the emergency measures taken in Argentina. In this regard, we have filed a Notice of Dispute against the Argentine government under the Bilateral Investment Treaty asserting that actions taken by the government are contrary to the rights granted to investors under the treaty. Any opportunity for recovery under the treaty is uncertain.

The 2001 asset impairment charges of $107 million resulted primarily from a $39 million write-down in our Merchant Energy segment for our investment in East Asia Power, an international power project in the Philippines, a $45 million write-down for our investment in Velocom, a telecommunications company in Brazil, and $15 million for our investment in Telergy, a telecommunication provider in the New York metropolitan area. Our telecommunications impairments have been included in our Corporate and Other operations. These impairments were a result of weak or changing economic conditions causing permanent declines in the value of these assets, and the charges taken were based on a comparison of each asset's carrying value to its estimated fair value based on future estimated cash flows.

5. Ceiling Test Charges

Under the full cost method of accounting for natural gas and oil production properties, we perform quarterly ceiling tests to evaluate whether the carrying value of natural gas and oil production 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.

During the nine months ended September 30, 2002, we recorded ceiling test charges of $267 million, of which $33 million was charged during the first quarter and $234 million was charged during the second quarter. The write-down includes $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. The charge for the Canadian full cost pool primarily resulted from a low daily posted price for natural gas at June 30, 2002, which was approximately $1.43 per million British thermal units.

For the nine months ended September 30, 2001, we recorded ceiling test charges of $135 million, including $87 million for our Canadian full cost pool, $28 million for our Brazilian full cost pool, and $20 million for other international production operations, primarily in Turkey. Our third quarter 2001 charges are based on the daily posted gas and oil prices as of November 1, 2001, adjusted for oilfield or gas gathering hub and wellhead price differences as appropriate. Had we computed the third quarter 2001 ceiling test charges based upon the daily posted gas and oil prices as of September 30, 2001, we would have incurred a ceiling test charge of $275 million. The amount would have included $227 million for our Canadian full cost pool and $48 million for our Brazilian full cost pool and other international production operations.

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. Had the impact of our hedges not been included in calculating our third quarter 2001 ceiling test charges, we would have incurred a third quarter charge of $576 million at September 30, 2001, relating to our domestic full cost pool. The charges for our international cost pools would not have materially changed since we do not significantly hedge our international production activities.

6. Changes in Accounting Estimates

Included in our operation and maintenance costs for the quarter and nine months ended September 30, 2001, were approximately $113 million and $316 million in costs related to changes in accounting estimates. The costs for the nine months ended September 30, 2001, consist of $229 million in additional environmental remediation liabilities, $48 million in additional accrued legal obligations and a $39 million charge to reduce the value of our spare parts inventories to reflect changes in the usability of these parts in our worldwide operations. The change in our estimated environmental remediation liabilities was due to a number of events, including $109 million resulting from the sale of a majority of our retail gas stations, $31 million related to our closure of our Gulf Coast Chemical and Midwest refining operations, $10 million associated with the lease of our Corpus Christi refinery to Valero, and $79 million associated with conforming Coastal's methods of environmental identification, assessment and remediation strategies and processes to our historical practices following our merger with Coastal. The change in estimate of our legal obligations was a result of a review process to assess our legal exposures, strategies and plans following the merger with Coastal. Finally, the charge related to our spare parts inventories was primarily the result of several events that occurred as part of and following our merger with Coastal, including the consolidation of numerous operating locations, the sale of a majority of our retail gas stations, the shutdown of our Midwest refining operations and the lease of our Corpus Christi refinery. These charges were also a direct result of a fire at our Aruba refinery whereby a portion of the plant was rebuilt following the fire rendering many of these parts unusable. Also impacting these amounts was the evaluation of the operating standards, strategies and plans of our combined company following the merger. Our changes in accounting estimates have reduced our after-tax earnings by approximately $76 million and $214 million for the quarter and nine months ended September 30, 2001.

7. Discontinued Operations

In June 2002, our Board of Directors authorized the sale of our coal mining operations. These operations, which have historically been included in our Merchant Energy segment, consist 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 in the second and third quarters of 2002. Because this carrying value was higher than our estimated net sales proceeds, we recorded impairment charges of $148 million in the second quarter of 2002 and $37 million in the third quarter of 2002.

We expect that our coal mining business will be sold in two parts: (1) coal reserves and properties and (2) coal mining operations. In November 2002, we announced an agreement to sell substantially all of our reserves and properties in West Virginia, Virginia and Kentucky to an affiliate of Natural Resources Partners, L.P. for $69 million. We expect to complete the sale, subject to regulatory reviews and approvals, in the fourth quarter of 2002. We expect to enter into agreements to sell the coal mining operations within the next six months.

Our coal mining operations have been classified as discontinued operations in our financial statements for all periods presented. In addition, we reclassified all of the assets and liabilities of our coal mining operations as of September 30, 2002 to other current assets and liabilities since we plan to sell them in the next twelve months. The summarized financial results of discontinued operations are as follows:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
	(In millions)			
Operating Results:				
Revenues	$ 75	$ 64	$ 243	$ 206
Costs and expenses	(95)	(64)	(259)	(210)
Asset impairments	(37)	—	(185)	—
Other income, net	—	1	6	3
Income (loss) before income taxes	(57)	1	(195)	(1)
Income tax benefit	21	—	73	—
Income (loss) from discontinued operations, net of income taxes	$(36)	$ 1	$(122)	$ (1)

	September 30, 2002	December 31, 2001
	(In millions)	
Financial Position Data:		
Assets of discontinued operations		
Accounts receivable	$ 26	$ 35
Inventory	12	11
Property, plant and equipment, net	101	301
Other	15	5
Total assets	$154	$352
Liabilities of discontinued operations		
Accounts payable and other	$ 24	$ 37
Environmental remediation reserve	15	—
Total liabilities	$ 39	$ 37

8. Extraordinary Items

Under a Federal Trade Commission order, as a result of our January 2001 merger with Coastal, we sold our Midwestern Gas Transmission system, our Gulfstream pipeline project, our 50 percent interest in the Stingray and U-T Offshore pipeline systems, and our investments in the Empire State and Iroquois pipeline systems. For the nine months ended September 30, 2001, net proceeds from these sales were approximately $279 million. We recognized extraordinary net gains of approximately $26 million, net of income taxes of approximately $27 million, including a third quarter 2001 charge of $5 million to record additional estimated income taxes on these sales.

9. Earnings Per Share

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

	Quarter Ended September 30,			
	2002		2001	
	Basic	Diluted	Basic	Diluted
	(In millions, except per common share amounts)			
Income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	$ (33)	$ (33)	$ 215	$ 215
Interest on trust preferred securities and preferred stock dividends, net of income taxes	—	—	—	3
Adjusted income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	(33)	(33)	215	218
Discontinued operations, net of income taxes	(36)	(36)	1	1
Extraordinary items, net of income taxes	—	—	(5)	(5)
Adjusted net income (loss)	$ (69)	$ (69)	$ 211	$ 214
Average common shares outstanding	586	586	506	506
Effect of dilutive securities				
Stock options	—	—	—	3
Restricted stock	—	—	—	—
FELINE PRIDES℠	—	—	—	3
Equity security units	—	—	—	—
Trust preferred securities	—	—	—	8
Average common shares outstanding[(1)]	586	586	506	520
Earnings per common share				
Income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	$(0.06)	$(0.06)	$ 0.43	$ 0.42
Discontinued operations, net of income taxes	(0.06)	(0.06)	—	—
Extraordinary items, net of income taxes	—	—	(0.01)	(0.01)
Adjusted net income (loss)	$(0.12)	$(0.12)	$ 0.42	$ 0.41

(1) Due to their antidilutive effect on earnings per common share, for 2002, we excluded a total of 16 million shares for all potentially dilutive securities, and for 2001, we excluded a total of 8 million shares for the assumed conversion of convertible debentures.

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

	Nine Months Ended September 30,			
	2002		2001	
	Basic	Diluted	Basic	Diluted
	(In millions, except per common share amounts)			
Income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	$ 223	$ 223	$ (307)	$ (307)
Discontinued operations, net of income taxes	(122)	(122)	(1)	(1)
Extraordinary items, net of income taxes	—	—	26	26
Cumulative effect of accounting changes, net of income taxes	168	168	—	—
Adjusted net income (loss)	$ 269	$ 269	$ (282)	$ (282)
Average common shares outstanding	548	548	504	504
Effect of dilutive securities				
Stock options	—	1	—	—
Restricted stock	—	—	—	—
FELINE PRIDES^{SM}	—	—	—	—
Equity security units	—	—	—	—
Trust preferred securities	—	—	—	—
Average common shares outstanding[(1)]	548	549	504	504
Earnings per common share				
Income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	$ 0.41	$ 0.41	$(0.61)	$(0.61)
Discontinued operations, net of income taxes	(0.22)	(0.22)	—	—
Extraordinary items, net of income taxes	—	—	0.05	0.05
Cumulative effect of accounting changes, net of income taxes	0.30	0.30	—	—
Adjusted net income (loss)	$ 0.49	$ 0.49	$(0.56)	$(0.56)

(1) Due to their antidilutive effect on earnings per common share, for 2002, we excluded a total of 16 million shares for all potentially dilutive securities, and for 2001, we excluded a total of 25 million shares for the assumed conversion of stock options, restricted stock, preferred stock, FELINE PRIDES^{SM}, trust preferred securities and convertible debentures.

10. 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 September 30, 2002 and December 31, 2001:

	September 30, 2002	December 31, 2001
	(In millions)	
Net assets (liabilities)		
Energy contracts		
Trading contracts[(1)(3)]	$ 968	$1,295
Non-trading contracts[(2)(3)]		
Derivatives designated as hedges	(357)	459
Other derivatives	957	—
Total energy contracts	1,568	1,754
Interest rate and foreign currency contracts	(5)	(33)
Net assets from price risk management activities[(4)]	$1,563	$1,721

(1) Trading contracts represent those that qualify for accounting under EITF Issue No. 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities.* See Note 18 for a discussion of changes in the accounting rules that will impact our accounting for energy trading contracts.

(2) Non-trading contracts include hedges related to our natural gas and oil producing activities and derivatives from our power contract restructuring activities.

(3) We do not recognize gains on the fair value of trading or non-trading positions beyond ten years unless there is clearly demonstrated liquidity in a specific market.

(4) 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.

Included in other derivatives as of September 30, 2002, are $963 million of derivative contracts related to the power restructuring activities of our consolidated subsidiaries. Of this amount, $872 million relates to a power restructuring that occurred during the first quarter of 2002 at our Eagle Point Cogeneration power plant, and $91 million relates to a 2001 power restructuring at our Capitol District Energy Center Cogeneration Associates plant. The remaining balance in other derivatives, an unrealized loss of $6 million, relates to 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 natural gas and oil properties that were sold during 2002.

The fair value of the derivatives related to our power restructuring activities is determined based on the expected cash receipts and payments under the contracts using future power prices compared to the contractual prices under these contracts. We discount these cash flows at an interest rate commensurate with the term of each contract and the credit risk of each contract's counterparty. We make adjustments to this discount rate when we believe that market changes in the rates result in changes in fair values that can be realized. We consider whether changes in the rates are the result of changes in the capital markets, or are the result of sustained economic changes. During the third quarter, treasury rates declined. We did not adjust our discount rate for this decline in treasury rates since this decrease, combined with the significant uncertainties in the capital markets, did not result in an increased fair value that we believe could have been realized in the market. We also adjust our valuations for factors such as market liquidity, market price correlation and model risk, as needed. Future power prices are based on the forward pricing curve of the appropriate power delivery and receipt points in the applicable power market. This forward pricing curve is derived from a combination of actual prices observed in the applicable market, price quotes from brokers and extrapolation models that rely on actively quoted prices and historical information. The timing of cash receipts and payments are based on the expected timing of power delivered under these contracts. The fair value of our derivatives may change each period based on changes in actual and projected market prices, fluctuations in the credit ratings of our counterparties, significant changes in interest rates, and changes to the assumed timing of deliveries.

In May 2002, we announced a plan to reduce the volumes of natural gas that we have hedged for our Production segment, and we removed the hedging designation on derivatives that had a fair value loss of

$91 million at September 30, 2002. This amount, net of income taxes of $33 million, is reflected in accumulated other comprehensive income and will be reclassified to income as the original hedged transactions are settled through 2004. Of the net loss of $58 million in accumulated other comprehensive income, we estimate that unrealized losses of $20 million, net of income taxes, related to these derivatives will be reclassified to income over the next twelve months.

11. Inventory

Our inventory consisted of the following:

	September 30, 2002	December 31, 2001
	(In millions)	
Refined products, crude oil and chemicals	$595	$577
Materials and supplies and other	208	197
NGL and natural gas in storage	25	41
	$828	$815

12. Debt and Other Credit Facilities

At September 30, 2002, our weighted average interest rate on our commercial paper and short-term credit facilities was 2.4%, and at December 31, 2001, it was 3.2%. We had the following short-term borrowings and other financing obligations:

	September 30, 2002	December 31, 2001
	(In millions)	
Current maturities of long-term debt and other financing obligations	$617	$1,799
Commercial paper	258	1,265
Notes payable	63	139
Short-term credit facility	—	111
	$938	$3,314

Our commercial paper program is currently rated at A3/P3. As a result, we do not have the current ability to issue commercial paper at attractive rates. Through the date of this filing, we repaid all of our outstanding commercial paper, except for $8 million.

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.

Issuances

Date	Company	Type	Interest Rate	Principal	Net Proceeds	Due Date
				(In millions)		
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[1]	Senior secured notes	7.75%	92	90	2008
May	El Paso	Euro notes	7.125%	494[2]	447	2009
June	El Paso	Senior notes[3]	6.14%	575	558	2007
June	El Paso	Notes[4]	7.875%	500	494	2012
June	EPNG	Notes[4]	8.375%	300	297	2032
June	TGP	Notes	8.375%	240	237	2032
July	Utility Contract Funding[1]	Senior secured notes	7.944%	829	786	2016

(1) These notes are collateralized solely by the cash flows and contracts of these consolidated subsidiaries, and are non-recourse to other El Paso companies. The Mohawk River Funding IV financing relates to our Capitol District Energy Center Cogeneration Associates restructuring transaction, and the Utility Contract Funding financing relates to our Eagle Point Cogeneration restructuring transaction.

(2) Represents the U.S. dollar equivalent of 500 million Euros at September 30, 2002, and includes a $44 million change in value due to a change in the Euro to U.S. dollar foreign currency exchange rate from the issuance date to September 30, 2002.

(3) These senior notes relate to an offering of 11.5 million 9% equity security units, which include forward purchase contracts on El Paso common stock to be settled on August 16, 2005. See Note 14 for further discussion.

(4) We have committed to exchange these notes for new registered notes. The form and terms of the new notes will be identical in all material respects to the form and terms of these old notes except that the new notes (1) will be registered with the Securities and Exchange Commission, (2) will not be subject to transfer restrictions and (3) will not be subject, under certain circumstances, to an increase in the stated interest rate.

Retirements

Date	Company	Type	Interest Rate	Principal	Net Payments	Due Date
				(In millions)		
2002						
January	SNG	Long-term debt	7.85%	$ 100	$ 100	2002
January	EPNG	Long-term debt	7.75%	215	215	2002
March	El Paso CGP	Long-term debt	Variable	400	400	2002
April	El Paso	Long-term debt	8.78%	25	25	2002
May	SNG	Long-term debt	8.625%	100	100	2002
June	El Paso CGP	Crude oil prepayment	Variable	300	300	2002
June	El Paso CGP	Long-term debt	Variable	90	90	2002
Jan.-June	El Paso Production	Natural gas production payment	LIBOR+ 0.372%	216	216	2002-2005
July	El Paso CGP	Long-term debt	Variable	55	55	2002
July-Aug.	El Paso(1)	Long-term debt	7.00%	30	22	2011
July-Aug.	El Paso(1)	Long-term debt	7.875%	35	27	2012
August	El Paso(1)	Long-term debt	6.75%-7.625%	19	15	2005-2011
August	El Paso CGP(1)	Long-term debt	6.20%	10	9	2004
August	El Paso CGP	Long-term debt	6.625%	460	25(2)	2004
June-Aug.	El Paso CGP	Long-term debt	Variable	51	51	2010-2028
September	El Paso CGP	Long-term debt	8.125%	250	250	2002
Jan.-Sep.	El Paso CGP	Long-term debt	Variable	106	106	2002
Jan.-Sep.	Various	Long-term debt	Various	32	32	2002
October	El Paso Tennessee	Long-term debt	7.875%	12	12	2002
Oct.-Nov.	El Paso CGP	Crude oil prepayment	Variable	133	133	2002
Oct.-Nov.	El Paso	Long-term debt	Various	12	12	2002
November	El Paso CGP	Long-term debt	Variable	60	60	2002

(1) These amounts represent a buyback of our bonds in the open market in July and August 2002.

(2) The majority of this debt was exchanged for equity. See Note 14 for further discussion.

Credit Facilities

In May 2002, we renewed our $3 billion, 364-day revolving credit and competitive advance facility. El Paso Natural Gas Company (EPNG) and Tennessee Gas Pipeline Company (TGP), our subsidiaries, remain designated borrowers under this facility and, as such, are liable for any amounts outstanding. This facility matures in May 2003. In June 2002, we amended our existing $1 billion, 3-year revolving credit and competitive advance facility to permit us to issue up to $500 million in letters of credit and to adjust pricing terms. This facility matures in August 2003, and El Paso CGP Company (formerly The Coastal Corporation), EPNG and TGP are designated borrowers under this facility and, as such, are liable for any amounts outstanding. The interest rate under both of these facilities varies based on our senior unsecured debt rating, and as of September 30, 2002, an initial draw would have had a rate of LIBOR plus 0.625%, plus a 0.25% utilization fee for drawn amounts above 25% of the committed amounts. As of September 30, 2002, there were no borrowings outstanding; however, we have issued $492 million of letters of credit under the $1 billion facility.

In September 2002, Moody's lowered our senior unsecured debt rating from Baa2 to Baa3, and in November 2002, Standard and Poor's lowered our senior unsecured debt rating from BBB to BBB-. As a result of these actions, the current interest rate on an initial draw under both of our credit facilities would be at a rate of LIBOR plus 0.80%, plus a 0.25% utilization fee for drawn amounts above 25% of the committed amounts.

Restrictive Covenants

We and our subsidiaries have entered into debt instruments and guaranty agreements that contain covenants such as restrictions on debt levels, restrictions on liens securing debt and guarantees, restrictions on mergers and on the sales of assets, capitalization requirements, dividend restrictions and cross-payment default and cross-acceleration provisions. A breach of any of these covenants could result in acceleration of our debt and other financial obligations and that of our subsidiaries.

Under our revolving credit facilities, the significant debt covenants and cross defaults are:

(a) the ratio of consolidated debt and guarantees to capitalization cannot exceed 70 percent (excluding certain project financing and securitization programs and other miscellaneous items);

(b) the consolidated debt and guarantees (other than excluded items) of our subsidiaries cannot exceed the greater of $600 million or 10 percent of our consolidated net worth;

(c) we or our principal subsidiaries cannot permit liens on the equity interest in our principal subsidiaries or create liens on assets material to our consolidated operations securing debt and guarantees (other than excluded items) exceeding the greater of $300 million or 10 percent of our consolidated net worth, subject to certain permitted exceptions; and

(d) the occurrence of an event of default for any non-payment of principal, interest or premium with respect to debt (other than excluded items) in an aggregate principal amount of $200 million or more; or the occurrence of any other event of default with respect to such debt that results in the acceleration thereof.

We were in compliance with the above covenants as of the date of this filing, and no borrowings were outstanding under our revolving credit facilities; however, we have issued $492 million of letters of credit under the $1 billion facility.

We have also issued various guarantees securing financial obligations of our subsidiaries and unconsolidated affiliates with similar covenants as in the above credit facilities.

With respect to guarantees issued by our subsidiaries, the most significant debt covenant, in addition to the covenants discussed above, is that El Paso CGP maintain a minimum net worth of $1.2 billion. If breached, the amounts guaranteed by the guaranty agreements could be accelerated. The guaranty agreements also have a $30 million cross-acceleration provision.

In addition, three of our subsidiaries have indentures associated with their public debt that contain $5 million cross-acceleration provisions.

13. Commitments and Contingencies

Legal Proceedings

California Lawsuits. We and several of our subsidiaries have been named as 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). 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 post-judgment interest, (v) costs of prosecuting the actions and (vi) attorney's fees. The lawsuits have been consolidated before a single judge and are at the preliminary pleading stages with trial scheduled for September 2003 on several of the cases. 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 lawsuits. The derivative suit originally was filed in California, but was dismissed and refiled in Texas in March 2002. At this time, our legal exposure related to these lawsuits and claims is not determinable.

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 are continuing to cooperate in responding to their discovery requests.

Nevada Lawsuit. The state of Nevada and four individuals have purportedly filed a lawsuit in District Court for Clark County, Nevada on November 1, 2002, naming us and a number of our subsidiaries and affiliates as defendants. While the complaint has not yet been served on us, we believe that its allegations are similar to those in the California cases. The suit purportedly seeks unquantified monetary damages, to be trebled, general and special damages and attorney fees and costs.

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 officers. Eleven of these suits are now consolidated in federal court in Houston before a single judge (a list of these suits is included in Part II, Item 1, Legal Proceedings). The suits generally challenge the accuracy or completeness of press releases and other public statements made during 2001 and 2002. 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 and generally alleges the same claims as those made in the consolidated shareholder class action lawsuit. The twelfth shareholder class action lawsuit was filed in federal court in New York City in October 2002 and challenges the accuracy or completeness of our February 27, 2002 prospectus for an equity offering that was completed on June 21, 2002 (a list of the shareholder derivative suits is included in Part II, Item I, Legal Proceedings). We have not been formally served with this lawsuit.

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 Proposed Violation against EPNG. The Notice alleged five violations of its regulations (a list of the alleged five violations is included in Part II, Item 1, Legal Proceedings), proposed fines totaling $2.5 million and proposed corrective actions. We have fully accrued for these fines. In October 2001, EPNG filed a response with the Office of Pipeline Safety disputing each of the alleged violations. 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. EPNG is cooperating with the National Transportation Safety Board in an investigation into the facts and circumstances concerning the possible causes of the rupture. On November 1, 2002, EPNG received a federal grand jury subpoena for documents relating to the rupture and will comply fully with the subpoena. In addition, a number of personal injury and wrongful death lawsuits were filed against EPNG in connection with the rupture. All but one of these suits have been settled. The settlement payments have been fully covered by insurance. In connection with the settlement of the cases, EPNG has agreed to contribute $10 million to a charitable foundation as a memorial to the families involved. This contribution will not be covered by insurance. The remaining case is *Geneva Smith, et al vs. EPEC and EPNG* filed October 23, 2000 in Harris County, Texas.

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.

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 gas working interest owners and 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. The plaintiffs' motion for class certification has been filed and we have filed our response.

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 five such lawsuits 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 these lawsuits and claims are not currently determinable.

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

For each of our outstanding legal matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we establish the necessary accruals. As of September 30, 2002, we had approximately $139 million accrued for all outstanding legal matters, including $10 million accrued for our contribution to a charitable foundation.

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 September 30, 2002, we had accrued approximately $518 million, including approximately $492 million for expected remediation costs and associated onsite, offsite and groundwater technical studies, and approximately $26 million for related environmental legal costs, which we anticipate incurring through 2027. Approximately

$15 million of the accrual was related to discontinued coal mining operations. Our reserves are based on the following estimates of reasonably possible outcomes:

	September 30, 2002	
Sites	Low	High
	(In millions)	
Operating	$226	$314
Non-operating	226	321
Superfund	33	45

Below is a reconciliation of our accrued liability as of December 31, 2001 to our accrued liability as of September 30, 2002 (in millions):

Balance as of December 31, 2001	$564
Additions/adjustments for remediation activities	13
Payments for remediation activities	(43)
Other changes, net	(16)
Balance as of September 30, 2002	$518

In addition, we expect to make capital expenditures for environmental matters of approximately $318 million in the aggregate for the years 2002 through 2007. These expenditures primarily relate to compliance with clean air regulations. For the fourth quarter of 2002, we estimate that our total expenditures will be approximately $29 million, of which $1 million we estimate will be for capital related expenditures. In addition, approximately $20 million of this amount will be expended under government directed clean-up plans. The remaining $8 million will be self-directed or in connection with facility closures.

Internal PCB Remediation Project. Since 1988, TGP, our subsidiary, 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.

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 agreed orders with the agency to resolve many of the issues raised in the complaint. The relevant Kentucky compressor stations are being remediated under the 1994 consent order with the EPA. Despite TGP's remediation efforts, the agency may raise additional technical issues or seek additional remediation work in the future.

PCB Cost Recoveries. In May 1995, following negotiations with its customers, TGP filed an agreement with the 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 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 September 30, 2002, TGP has over-collected PCB costs by approximately $114 million. The over-collection will be reduced by future eligible costs incurred for the remainder of the remediation project. TGP is required to refund to its customers the over-collection amount to the extent actual eligible expenditures are less than amounts collected. As of September 30, 2002, TGP has recorded a regulatory liability (included in other non-current liabilities on our balance sheet) for future refund obligations of approximately $53 million. This agreement also provides for carrying charges incurred up to the date of the refunds.

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. All of the assessments are related to alleged noncompliance 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. At the agency's request, the administrative law judge put the hearings on inactive status until December 2002 to allow time for settlement discussions.

EPA Fuel Regulations. 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 have settled with the EPA for $120,000. The settlement agreement also includes an additional $52,500 penalty for a self-disclosed fuels noncompliance. We expect to pay the total settlement of $172,500 in the fourth quarter of 2002.

CERCLA Matters. 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 57 active sites under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) or state equivalents. We have sought to resolve our liability as a PRP at these sites through indemnification by third parties and settlements which provide for payment of our allocable share of remediation costs. As of September 30, 2002, we have estimated our share of the remediation costs at these sites to be between $30 million and $41 million, and we have established reserves which are included in the environmental reserves discussed above. We believe our reserves 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 determining our estimated liabilities.

Rates and Regulatory Matters

Wholesale Power Customers' Complaints. In late 2001 and early 2002, several wholesale power customers filed complaints (a list of the complaints is included in Part II, Item 1, Regulatory Proceedings) with the FERC against El Paso Merchant Energy, L.P. (EPME) and other wholesale power marketers. These customers entered into contracts with EPME and other wholesale power suppliers for the purchase of power to be delivered in the future. Based on allegations in the complaints, these 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). EPME and other respondents believe the allegations in the complaint are without merit and have asked the FERC to dismiss these complaints. A hearing relating to the first complaint was completed on October 22, 2002 and an initial decision from the presiding administrative law judge (ALJ) is expected by December 31, 2002. Hearings for all but one of the remaining complaints are set for December 2002, with decisions in those cases by the respective presiding ALJs expected by late February 2003. The decisions of the ALJs will then be submitted to the FERC for its review. The FERC has not yet acted on the last complaint filed, so no hearing has been scheduled in that matter.

CPUC Complaint Proceeding. In April 2000, the Public Utilities Commission of the State of California (CPUC) filed a complaint under Section 5 of the Natural Gas Act (NGA) with the FERC alleging that the sale of approximately 1.2 billion cubic feet per day of capacity by EPNG to EPME, both of whom are our wholly owned subsidiaries, raised issues of market power, violation of FERC's marketing affiliate regulations and asked that the contracts be voided. Although the FERC held that EPNG did not violate its marketing affiliate requirements, it established a hearing before an ALJ to address the market power issue. In the spring and summer of 2001, two hearings were held before the ALJ to address the market power issue and, at the request of the ALJ, 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 and that accordingly the market power claims should be dismissed. The ALJ found, however, that EPNG had violated the marketing affiliate rules. EPNG and other parties filed briefs on exceptions and briefs opposing exceptions to the October initial decision.

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 our 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 recommended 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. EPNG and others filed briefs on exceptions to the initial decision on October 23, 2002. In support of EPNG's request, EPNG informed the FERC that the initial decision is inconsistent with the facts, the law, and FERC policy and urged the FERC to reverse it. Briefs opposing exceptions were filed on November 12, 2002. Oral argument, currently set for December 2, 2002, will be heard by the FERC commissioners prior to the issuance of an order on the initial decisions.

Systemwide Capacity Allocation Proceeding. In July 2001, several of EPNG's customers who hold contracts with volumetric ceilings (Contract Demand or CD customers) filed a complaint against EPNG at the FERC under Section 5 of the NGA claiming, among other things, that EPNG's full requirements contracts (contracts with no volumetric limitations) with customers located east of California (EOC) should be converted to CD contracts, that EPNG should be required to expand its system to serve all of its customers' growing requirements instead of relying on the pro rata allocation provisions of its FERC approved tariff to allocate its available capacity among its EOC and CD customers, and that EPNG should be required to give demand charge credits to its CD customers when EPNG is unable to meet their full contract demands. Likewise, in July 2001, several of EPNG's EOC customers filed a complaint under Section 5 of the NGA alleging that EPNG had violated the NGA and EPNG's contractual obligations to them by not expanding its system, at EPNG's own cost, to meet their increased requirements.

On May 31, 2002, the FERC issued an order on the complaints in which it required that (i) full requirements service, for all EOC customers other than small volume customers, be converted to service with specified volumetric rights (i.e., contract demand service); (ii) firm customers be assigned specific receipt point rights in lieu of their existing systemwide receipt point rights; (iii) EPNG prospectively give reservation charge credits to all firm customers for any failure to schedule confirmed volumes except in cases of force majeure; (iv) EPNG refrain from entering into new firm contracts until EPNG has demonstrated that it has adequate capacity on the system; and (v) EPNG conduct a process to allow existing CD customers to turn back capacity for acquisition by full requirements customers. The FERC indicated in the May 31 order that EPNG was to remain revenue neutral as a result of this turnback process. In addition, the order stated that the FERC expected EPNG to file for certificate authority to add compression to its Line 2000 project, thereby increasing its system capacity by 320 MMcf/d, without cost coverage until the next rate case (which will be January 1, 2006). EPNG had previously stated it was willing to add compression to the project at a public conference held in April 2002, provided it was assured of rate coverage in the next rate case. The May 31 order established dates by which the steps necessary to implement the order's requirements would be completed. The changes required by the order were to be made effective November 1, 2002.

On July 1, 2002, EPNG and numerous other parties filed for clarification and/or rehearing of the May 31 order. Although the order required the full requirements customers to agree among themselves on an appropriate allocation of unsubscribed westflow pipeline capacity by July 31, 2002, the customers failed to reach such an agreement. On September 20, 2002, the FERC issued an order postponing the effective date of the conversions required by their May 31 order until May 1, 2003. The order instructed EPNG to allocate among its full requirements customers the 320 MMcf/d of capacity that will be available once compression is added to Line 2000 (which the FERC estimated would be in the summer of 2003; however, EPNG anticipates the first and second phases of the compression will be in service by mid 2004, and has so advised the FERC). In addition, the order prohibited EPNG from reselling any firm capacity that expires under existing contracts between May 31, 2002, and May 1, 2003, requiring instead that EPNG allocate this capacity to its full requirements customers. In total, the September 20 order requires that EPNG's full requirements customers pay only their current reservation charges for existing unsubscribed capacity, for the 230 MMcf/d of capacity that was made available in November 2002 by the Line 2000 project, for the additional 320 MMcf/d of capacity to be available once the compression of Line 2000 is completed, and for all capacity subject to contracts expiring before May 1, 2003. Beginning May 1, 2003, EPNG will be required to pay reservation charge credits when it is unable to schedule confirmed volumes except in cases of force majeure. Between November 1, 2002, and May 1, 2003, EPNG is required to pay reservation charge credits to CD customers when it is unable to schedule 95 percent of their confirmed volumes except for reasons of force majeure and provided that there is no capacity available to meet their needs from other supply basins on its system.

Several pleadings have been filed in response to the September 20 order, including requests by several customers to modify the order based on the ALJ's decision in the CPUC Complaint Proceeding discussed above, requests by customers and others to vacate and/or stay the order and our responses to those pleadings, and numerous applications for rehearing and/or clarification filed by EPNG and others. All such motions and requests remain pending before the FERC. On November 1, 2002, the FERC issued a tolling order to allow it additional time to act upon the requests for rehearing and indicated that it anticipates issuing an order on rehearing by January 31, 2003. EPNG anticipates that in the order the FERC will address the various motions made as well as the requests for clarification and rehearing. In the interim, EPNG is proceeding with the directives contained in the September 20 order.

Line 2000 Project. On July 31, 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 EPNG's system, however, EPNG filed in March 2001 to amend its application to convert the project to an expansion project of 230 MMcf/d. On May 7, 2001, the FERC authorized the amended Line 2000 project. EPNG has received authorization to place the line in service, and anticipates having all segments of Line 2000 in service by mid-November 2002 at a total estimated capital cost of $185 million.

On October 3, 2002, pursuant to the FERC's May 31 and September 20 orders, EPNG applied 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 320 MMcf/d at an estimated capital cost of approximately $173 million for all phases. That application has been protested. In our request for clarification of the September 20 order, we have asked for assurances from the FERC that EPNG will be able to begin cost recovery for this project at the time its next rate case becomes effective.

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. In December 2001, we filed comments with the FERC addressing our concerns with the proposed rules. A public hearing was held on May 21, 2002, providing an opportunity to comment further on the NOPR. Following the conference, additional comments were filed by our pipeline subsidiaries and others. 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 NOI. In July 2002, the FERC issued a Notice of Inquiry (NOI) that seeks comments regarding its 1996 policy of permitting pipelines to enter into negotiated rate transactions. Several of our pipelines have entered into these 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, as well as other issues related to negotiated rate programs. On September 25, 2002, our pipelines and others filed comments. Reply comments were filed on October 25, 2002. At this time, we cannot predict the outcome of this NOI.

Cash Management NOPR. On August 1, 2002, the FERC issued a NOPR requiring that all cash management or money pool arrangements between a FERC regulated subsidiary and a non-FERC regulated parent must be in writing, and set forth: the duties and responsibilities of cash management participants and administrators; the methods of calculating interest and for allocating interest income and expenses; and the restrictions on deposits or borrowings by money pool members. The NOPR also requires specified documentation for all deposits into, borrowings from, interest income from, and interest expenses related to, these arrangements. Finally, the NOPR proposed that as a condition of participating in a cash management or money pool arrangement, the FERC regulated entity maintain a minimum proprietary capital balance of 30 percent, and the FERC regulated entity and its parent maintain investment grade credit ratings. On August 28, 2002, comments were filed. The FERC held a public conference on September 25, 2002, to discuss the issues raised in the comments. Representatives of companies from the gas and electric industries participated on a panel and uniformly agreed that the proposed regulations should be revised substantially and that the proposed capital balance and investment grade credit rating requirements would be excessive. At this time, we cannot predict the outcome of this NOPR.

Also on August 1, 2002, the FERC's Chief Accountant issued an Accounting Release, to be effective immediately, providing guidance on how companies should account for money pool arrangements and the types of documentation that should be maintained for these arrangements. However, the Accounting Release did not address the proposed requirements that the FERC regulated entity maintain a minimum proprietary capital balance of 30 percent and that the entity and its parent have investment grade credit ratings. Requests for rehearing were filed on August 30, 2002. The FERC has not yet acted on the rehearing requests.

Australia. 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 $200 million. EPIC Energy Australia 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 we received a favorable ruling in August 2002. The court directed the regulator to review its position and comply with applicable regulatory law. A resolution is expected in 2003. If the original 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 $140 million. Additionally, EPIC Energy (WA) Nominees Pty. Ltd. has debt of approximately AUD$1.8 billion (U.S.$1 billion) maturing in March 2003. Uncertainty about the future rates may impact this refinancing.

Southwestern Bell Proceeding. We are engaged in proceedings with Southwestern Bell involving disputes regarding our telecommunications interconnection agreement in our metropolitan transport business. In July 2002, we received a favorable ruling from the administrative law judge in Phase 1 of the proceedings. We anticipate a determination from the Public Utilities Commission (PUC) of Texas on the administrative law judge's recommendation no later than the first quarter of 2003. 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 could negatively impact our metro transport business. An adverse resolution to the proceeding by the PUC could have a negative impact on our ongoing operations and prospects in this business.

California Trading Strategies. EPME, our subsidiary, responded on May 22, 2002, to the FERC's May 8, 2002, request for statements of admission or denial with respect to trading strategies designed to manipulate California power markets. EPME provided an affidavit stating that it had not engaged in these trading strategies.

Wash Trade Inquiries. On May 21 and 22, 2002, the FERC issued data requests, 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).

On June 7, 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 on July 15, 2002. On July 12, 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 to all of the largest North American Gas Marketers, including EPME, regarding price reporting of transactional data to the energy trade press. We have engaged an outside firm to investigate fully the matters raised in the data request. We have identified at least one incident in which it appears that inaccurate pricing information may have been provided to a trade publication. We are cooperating fully with the FERC in this matter.

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. We cannot predict the outcome of this proceeding.

While the outcome of our outstanding legal matters, environmental matters and rates and regulatory matters cannot be predicted with certainty, based on the information we know now 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. 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 credit rating. See Item 2, Management's Discussion and Analysis under the subheading Recent Developments. 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 for 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 and on our cash flows in the period the event occurs.

Other Commercial Commitments

In 2001, our subsidiaries entered into agreements to time-charter four separate ships to secure transportation for our developing LNG business. In May 2002, we entered into amendments to three of the initial four time charters to reconfigure the ships with onboard regasification technology and to secure an option for an additional time charter for a fifth ship. The exercise of the option for the fifth ship will represent a commitment of $522 million over the term of such charter. However, we are obligated to pay a termination fee of $24 million in the event the option is not exercised by April 2003. The agreements provide for deliveries of vessels between 2003 and 2005. Each time charter has a twenty-year term commencing when the vessels are delivered with the possibility of two five-year extensions. The total commitment of our subsidiaries under the five time-charter agreements is approximately $2.5 billion over the term of the time charters. If our subsidiaries were unable to fulfill their obligations under the five time charter arrangements, our maximum commitment, in the form of corporate guarantees and letters of credit, would be $254 million, which will increase to $290 million if we exercise the option for the time charter on the fifth ship. We are party to an agreement with an unaffiliated global integrated oil and gas company under which the third party agrees to bear 50 percent of the risk incidental to the initial $1.8 billion commitment made for the first four time charters.

Other Matters

Enron Bankruptcy. 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 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 against Enron trading entities in an amount totaling approximately $318 million. After considering the cash margins Enron has deposited with us as well as the reserves we have established, our 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 broker quotes obtained from parties who are interested in buying our bankruptcy claim position.

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 order in the EPNG capacity allocation proceeding discussed in *Rates and Regulatory Matters* above prohibits it from remarketing Enron capacity that was not remarketed prior to May 31, 2002. EPNG has sought rehearing of the September 20 order. 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 that date.

As a result of current circumstances surrounding the energy sector, the creditworthiness of several industry participants has been called into question. We have taken actions to mitigate our exposure to these participants; however, should several industry participants file for Chapter 11 bankruptcy protection and 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.

Broadwing Arbitration. In June 2000, El Paso Global Networks (EPGN), formerly known as El Paso Communications Company, entered into an agreement with Broadwing Communications Services 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. However, if we are unsuccessful in our claim against Broadwing or should they become financially insolvent, we may be subject to a substantial write-down or complete write-off of this route. Although the outcome of the arbitration is uncertain, the final result could have a material impact on the value of our fiber optic route from Houston, Texas to Los Angeles, California, in which we had total invested capital of $109 million as of September 30, 2002.

Economic Conditions of Brazil. We have investments in power, pipeline and production projects in Brazil, including an investment in Gemstone, with an aggregate exposure, including financial guarantees, of approximately $1.8 billion. During the second and third quarters of 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 October 2002. These concerns have contributed to 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 68 percent devaluation of the local currency against the U.S. dollar since the end of the first quarter of 2002. These developments are likely to delay the implementation of project financings underway in Brazil. The International Monetary Fund recently announced a $30 billion loan package for Brazil; however, the release of the majority of the money will depend on Brazil committing to specified fiscal targets in 2003. In addition, Brazil's newly elected President may impose changes affecting our business, including imposing tariff controls on electricity and fuels. 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 any potential changes in governmental policy. Future developments in Brazil could cause us to reassess our exposure.

Meizhou Wan Power Project. We own a 25 percent equity interest in a 762 megawatt, coal-fired power generating project, Meizhou Wan Generating, located in Fuzhou, People's Republic of China. Our investment in the project was $76 million at September 30, 2002, and we have also issued $35 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. The price the project 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. If the project is unable to reach a long-term agreement with the provincial government, with higher rates than in the interim agreement, we could be required to impair our investment in the project, since cash flows from the project would not be sufficient to provide us with a return of our investment, and we may incur additional losses if our guarantees and letters of credit are called upon. Our losses are limited to the extent of our investment, guarantees and letters of credit.

Milford Power Project. We own a 25 percent direct equity interest in a 540 megawatt power plant construction project located in Milford, Connecticut. Chaparral, our affiliate, owns an additional 70 percent interest in this project. 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 expires on December 2, 2002. Between now and December 2, 2002, we will be negotiating with the contractor and with the lending banks to attempt to reach agreements on contract disputes, including resolution of liquidated damages that are due to the project under the terms of the construction contract and for successful completion of plant construction. We may be unable to reach a negotiated settlement of the disputes prior to December 2, 2002, in which case the lending banks may have the right to accelerate the construction loan and foreclose on the project resulting in an impairment of our investment in the project. At September 30, 2002, our direct investment in the project was $79 million, and Chaparral's investment was $47 million. We estimate that if the investment were written off in its entirety, the charge we would incur would be approximately $126 million based on both our direct investment in the project and our indirect investment through Chaparral. We have also provided a guarantee of $8 million to fund a debt service account for Milford. We may be required to fund the account should the facility not be financially able to do so within two years from its commercial operations date.

Berkshire Power Project. We own a 25 percent direct equity interest in a 272 megawatt power plant located in Massachusetts. Chaparral, our affiliate, owns an additional 31.4 percent interest in this project. 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, including fuel oil firing capability. During the third quarter of 2002, the project lenders asserted that Berkshire was in default on its loan agreement. Berkshire is in the process of negotiating with its lenders to resolve disputed contract terms. Failure to reach a satisfactory resolution in these matters could have a material adverse effect on the value of our investment in the project. At September 30, 2002, our direct investment in Berkshire was $26 million, including receivables of $18 million under a subordinated fuel agreement, and Chaparral's investment was $5 million.

14. Capital Stock

Common Stock

In May 2002, we increased our authorized capitalization to 1.5 billion shares of common equity. In June 2002, we issued approximately 51.8 million additional shares of common stock for approximately $1 billion, net of issuance costs of approximately $31 million.

Equity Security Units

In June 2002, we issued 11.5 million, 9% equity security units. Equity security units consist of two securities: i) a purchase contract on which we will pay quarterly contract adjustment payments at an annual rate of 2.86% and that requires its holder to buy El Paso common stock to be settled on August 16, 2005, and ii) a senior note due August 16, 2007, with a principal amount of $50 per unit, and on which we will pay quarterly interest payments at an annual rate of 6.14% beginning August 16, 2002. The senior notes we issued had a total principal value of $575 million and are pledged to secure the obligation to purchase shares of our common stock under the purchase contracts.

When the purchase contracts are settled in 2005, we will issue El Paso common stock. At that time, the proceeds will be allocated between common stock and additional paid-in capital. The number of common shares issued will depend on the prior 20-trading day average closing price of our common stock determined on the third trading day immediately prior to the stock purchase date. We will issue a minimum of approximately 24 million shares and up to a maximum of 28.8 million shares on the settlement date, depending on our average stock price. We recorded approximately $43 million of other non-current liabilities to reflect the present value of the quarterly contract adjustment payments that we will be required to make on these units at an annual rate of 2.86% of the stated amount of $50 per purchase contract with an offsetting reduction in additional paid-in capital. The quarterly contract adjustment payments will be allocated between the liability recognized at the date of issuance and additional paid-in capital based on a constant rate over the term of the purchase contracts.

Fees and expenses incurred in connection with the equity security units offering were allocated between the senior notes and the purchase contracts based on their respective fair values on the issuance date. The amount allocated to the senior notes will be recognized as interest expense over the term of the senior notes. The amount allocated to the purchase contracts was recorded as additional paid-in capital.

FELINE PRIDES^{SM}

In August 2002, we issued 12,184,444 shares of common stock to satisfy purchase contract obligations under our FELINE PRIDES^{SM} program. In return for the issuance of stock, we received approximately $25 million in cash from the maturity of a zero coupon bond and the return of $435 million of our existing

6.625% senior debentures due August 2004, that were issued in 1999. The zero coupon bond and the senior debentures had been held as collateral for the purchase contract obligations. The $25 million received from the maturity of the zero coupon bond was used to retire additional senior debentures. Total debt reduction from the issuance of the common stock was approximately $460 million.

Preferred Stock

As part of our balance sheet enhancement plan announced in December 2001, we completed amendments to our Chaparral and Gemstone agreements in 2002 which reduced the number of Series B Mandatorily Convertible Single Reset Preferred Stock issued in connection with the Chaparral third party notes to 40,000 shares in April 2002, and eliminated all of the Series C Mandatorily Convertible Single Reset Preferred Stock issued in connection with the Gemstone third party notes in May 2002.

Dividend

On November 7, 2002, we declared a quarterly dividend of $0.2175 per share on our common stock, payable on January 6, 2003, to stockholders of record on December 6, 2002. Also, during the nine months ended September 30, 2002, El Paso Tennessee Pipeline Co., our subsidiary, paid dividends of $19 million on our Series A cumulative preferred stock, which is 8¼% per annum (2.0625% per quarter).

15. Segment Information

We segregate our business activities into four distinct operating segments: Pipelines, Production, Merchant Energy 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. In the second quarter of 2002, we reclassified our historical coal mining operations from our Merchant Energy segment to discontinued operations in our financial statements. All periods were restated to 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 operating income, adjusted for several items, including: equity earnings from unconsolidated investments, minority interests on consolidated, but less than wholly-owned operating subsidiaries, gains and losses on sales of assets and other miscellaneous non-operating items. Items that are not included in this measure are financing costs, including interest and debt expense and returns on preferred interests of consolidated subsidiaries, income taxes, discontinued operations, extraordinary items and the impact of accounting changes. We believe this measurement is useful to our investors because it allows them to evaluate the effectiveness of our businesses and operations and our investments from an operational perspective, exclusive of the costs to finance those activities and exclusive of income taxes, neither of which are directly relevant to the efficiency of those operations. 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 cash flow. The following are our segment results as of and for the periods ended September 30:

	Quarter Ended September 30, 2002					
	Pipelines	Production	Merchant Energy	Field Services	Corporate & Other[1]	Total
	(In millions)					
Revenues from external customers	$ 551	$ 80	$ 1,628 [2]	$ 386	$ 11	$ 2,656
Intersegment revenues	58	419	(557) [2]	165	(85)	—
Operating income (loss)	261	180	(243)	21	(8)	211
EBIT	302	179	(171)	(11)	34	333

	Quarter Ended September 30, 2001					
	Pipelines	Production	Merchant Energy	Field Services	Corporate & Other[1]	Total
	(In millions)					
Revenues from external customers	$ 531	$ —	$ 2,260 [2]	$ 308	$ 67	$ 3,166
Intersegment revenues	78	609	(844) [2]	251	(94)	—
Merger-related costs and asset impairments	1	—	—	9	22	32
Ceiling test charges	—	135	—	—	—	135
Operating income (loss)	237	168	147	30	(103)	479
EBIT	274	169	253	43	(91)	648

	Nine Months Ended September 30, 2002					
	Pipelines	Production	Merchant Energy	Field Services	Corporate & Other[1]	Total
	(In millions)					
Revenues from external customers	$1,765	$ 391	$ 6,284 [2]	$ 923	$ 35	$ 9,398
Intersegment revenues	176	1,218	(1,856) [2]	669	(207)	—
Restructuring costs and asset impairments	1	—	353	1	50	405
Ceiling test charges	—	267	—	—	—	267
Operating income (loss)	880	357	(158)	85	(79)	1,085
EBIT	1,024	362	(18)	94	(5)	1,457

	Nine Months Ended September 30, 2001					
	Pipelines	Production	Merchant Energy	Field Services	Corporate & Other[1]	Total
	(In millions)					
Revenues from external customers	$1,813	$ 190	$ 6,936 [2]	$1,577	$ 374	$10,890
Intersegment revenues	240	1,578	(1,926) [2]	476	(368)	—
Merger-related costs and asset impairments	316	63	191	46	1,176	1,792
Ceiling test charges	—	135	—	—	—	135
Operating income (loss)	562	642	334	90	(1,403)	225
EBIT	676	643	647	134	(1,368)	732

(1) Includes our Corporate and telecommunication activities, eliminations of intercompany transactions and in 2001, our retail business. Our intersegment revenues, along with our intersegment operating expenses, consist of normal course of business-type transactions between our operating segments. We record an intersegment revenue elimination, which is the only elimination included in the "Other" column, to remove intersegment transactions.

(2) Merchant Energy revenues take into account the adoption of a consensus reached on EITF Issue No. 02-3, 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 Note 1 regarding the adoption of this Issue.

The reconciliations of EBIT to income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes and total assets are presented below:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
	(In millions)			
Total EBIT	$ 333	$ 648	$ 1,457	$ 732
Interest and debt expense	(342)	(280)	(1,008)	(866)
Returns on preferred interests of consolidated subsidiaries	(38)	(51)	(121)	(169)
Income taxes	14	(102)	(105)	(4)
Income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	$ (33)	$ 215	$ 223	$(307)

	September 30, 2002	December 31, 2001
	(In millions)	
Pipelines	$14,677	$14,443
Production	7,976	8,458
Merchant Energy	18,382	17,350
Field Services	2,814	3,581
Corporate and other	5,103	3,987
Total segment assets	48,952	47,819
Discontinued operations	154	352
Total consolidated assets	$49,106	$48,171

16. 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 an interest of 50 percent or less, as well as those in which we hold greater than a 50 percent interest. Our proportional share of the net income of the unconsolidated affiliates in which we hold a greater than 50 percent interest was $9 million and $14 million for the quarters ended, and $25 million and $39 million for the nine months ended September 30, 2002 and 2001.

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
	(In millions)			
Operating results data				
Operating revenues	$756	$520	$1,898	$1,929
Operating expenses	548	357	1,330	1,406
Income from continuing operations	123	90	283	261
Net income	124	90	284	253

Consolidation of Investments

As of December 31, 2001, we had investments in Eagle Point Cogeneration Partnership, Capitol District Energy Center Cogeneration Associates and Mohawk River Funding IV. During 2002, we obtained additional rights from our partners in each of these investments and also acquired an additional one percent ownership interest in Capitol District Energy Center 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 September 30, 2002 and December 31, 2001, the outstanding balance on these securities, plus accrued interest, was $125 million and $350 million.

In May 2002, we completed amendments to the Gemstone agreements by eliminating the stock price and credit rating triggers and eliminating $950 million of mandatorily convertible preferred stock that was held in a share trust we controlled. In connection with the elimination of these triggers, we issued an El Paso guarantee supporting Gemstone's notes in the amount of $950 million, which can be called on in the event Gemstone is unable to meet its obligations under its notes.

Chaparral

We have a credit facility with Chaparral that had an outstanding balance, plus accrued interest, of $698 million and $552 million at September 30, 2002 and December 31, 2001. The interest rate on the facility is based on LIBOR plus a margin, and was 2.3% and 2.6% at September 30, 2002 and December 31, 2001.

In April 2002, we completed amendments to the Chaparral agreements, eliminating the stock price and credit rating triggers and reducing the number of shares of mandatorily convertible preferred stock that was held in a share trust. In connection with the elimination of these triggers, we issued an El Paso guarantee supporting Chaparral's notes totaling approximately $1 billion, which can be called on in the event Chaparral is unable to meet its obligations under its notes.

As discussed more completely in our 2001 Form 10-K, we have entered into a number of transactions with Chaparral and its subsidiaries, including providing management and administrative services, capital contributions and being a party to a number of commercial contracts. As of September 30, 2002 and December 31, 2001, we had the following investment in Chaparral:

	September 30, 2002	December 31, 2001
	(In millions)	
Notes receivable	$ 305	$ 343
Credit facility receivable	698	552
Debt securities payable	(79)	(169)
Contingent interest promissory notes payable	(171)	(289)
	753	437
Equity investment	264	341
Total investment	$1,017	$ 778

As of September 30, 2002, Chaparral had $1.8 billion of consolidated third party debt. Chaparral's debt is related to specific projects that it owns or has interests in, and is recourse solely to those projects. Chaparral's equity consisted of our investment of $264 million and Limestone Investors' investment of $1.1 billion.

El Paso Energy Partners

A subsidiary in our Field Services segment serves as the general partner of El Paso Energy Partners, a master limited partnership that has limited partnership units that trade on the New York Stock Exchange. Field Services acquired the general partner in August 1998, together with an approximate 27.3 percent interest in the common units of the master limited partnership. Since then, Field Services' ownership percentage in the common units of the limited partnership has decreased to 26.5 percent. The remaining 73.5 percent of the common units of the limited partnership are owned by public unit holders (including small amounts owned by the general partner's management and employees), none of which exceeds a 10 percent ownership interest. A majority of the members of the Board of Directors of El Paso Energy Partners are independent of us, and the audit and conflicts committee is completely comprised of independent members.

As the general partner, Field Services manages the partnership's daily operations, provides the strategic direction and performs all of the partnership's administrative and operational activities under a general and administrative services agreement or, in some cases, separate operational agreements. El Paso Energy Partners contributes to our income through our general partner interest and our ownership of common and preferred units. We do not have any loans to or from El Paso Energy Partners. In addition, except for a nominal guarantee of lease obligations on behalf of a subsidiary of El Paso Energy Partners, we have not provided any guarantees, either monetary or performance, on behalf of or for the benefit of El Paso Energy Partners nor do we have any other liabilities other than normal course of business as a result of or arising out of our role as the general partner or our ownership interest in El Paso Energy Partners. Our normal course of business transactions with El Paso Energy Partners include sales of natural gas and services, such as transportation and fractionation, storage, processing and other types of operational services.

In April 2002, we sold midstream assets to El Paso Energy Partners for total consideration of $735 million. In July 2002, we entered into a letter of intent with El Paso Energy Partners for the sale of the San Juan assets for $782 million. See Note 2 for further discussion.

17. Preferred Interests of Consolidated Subsidiaries

Clydesdale and Trinity River. In March 2002, we completed the amendments to the Trinity River (also known as Red River) agreements to remove the rating trigger that could have required us to liquidate the assets supporting the transaction in the event we were downgraded to below investment grade by both Standard and Poor's and Moody's. We completed a similar amendment for our Clydesdale (also known as Mustang) agreements in July 2002.

El Paso Oil & Gas Resources Preferred Units. In July 2002, we repurchased from UAGC, Inc., an unaffiliated investor, 50,000 units representing all outstanding preferred units in El Paso Oil & Gas Resources Company, L.P., our wholly owned partnership, for $50 million plus accrued and unpaid dividends.

Coastal Limited Ventures Preferred Stock. In July 2002, we repurchased from JPMorgan Chase Bank, an unaffiliated investor, 150,000 shares representing all outstanding preferred stock in Coastal Limited Ventures, Inc., our wholly owned subsidiary, for $15 million plus accrued and unpaid dividends.

Consolidated Partnership. In July 2002, we repurchased the limited partnership interest, from RBCC, Inc., an unaffiliated investor, in El Paso Production Oil & Gas Associates, L.P., a partnership formed with Coastal Limited Ventures, Inc. The payment of approximately $285 million to the unaffiliated investor was equal to the sum of the limited partner's outstanding capital plus unpaid priority returns.

18. 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 for the estimated retirement and removal costs of assets used in their business. The liability is recorded at its fair value, with a corresponding asset which is depreciated over the remaining useful life of the long-lived asset to which the liability relates. An ongoing expense will also be recognized for changes in the value of the liability as a result of the passage of time. The provisions of SFAS No. 143 are effective for fiscal years beginning after June 15, 2002. We are currently assessing and quantifying the asset retirement obligations associated with our long-lived assets. We expect to complete our assessment of these asset retirement obligations and be able to estimate their effect on our financial statements in the fourth quarter of 2002.

Accounting for Costs Associated with Exit or Disposal Activities

In July 2002, the FASB issued SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities.* This statement will require us to recognize costs associated with exit or disposal activities when they are incurred rather than when we commit to an exit or disposal plan. Examples of costs covered by this guidance include lease termination costs, employee severance costs associated with a restructuring, discontinued operations, plant closings or other exit or disposal activities. The statement is effective for fiscal years beginning after December 31, 2002, and will impact any exit or disposal activities we initiate after January 1, 2003.

Accounting for Contracts Involved in Energy Trading and Risk Management Activities

In October 2002, the EITF reached two decisions on EITF Issue No. 02-3, *Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities.* The first of the two decisions requires that we account for all energy-related contracts that do not qualify as derivatives under SFAS No. 133 using the accrual method of accounting, rather than mark-to-market accounting as was previously required under EITF Issue No. 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities.* Following our application of this consensus of EITF Issue No. 02-3, we will continue to record our derivative contracts at fair value under SFAS No. 133. The energy-related contracts not qualifying as derivatives will be those that require physical delivery or may have an element of service required under the contract. Examples of non-derivative energy contracts include transportation capacity contracts, storage contracts and tolling contracts.

The other consensus reached will require that we account for all inventory held by our energy-trading operation at the lower of its cost or fair value, rather than using mark-to-market accounting as was previously allowed under EITF Issue No. 98-10. Upon adoption we will adjust the fair value of these inventories in our balance sheet to their corresponding cost using an inventory valuation method (such as average cost) and record a cumulative effect of accounting change.

We will adopt these decisions during the fourth quarter of 2002, at which time we will be required to eliminate the fair value of non-derivative trading contracts from our balance sheet, adjust our inventory to reflect the lower of its cost or market value and record a cumulative effect of accounting change. At this time, we estimate that this will result in a cumulative effect loss of approximately $225 million to $350 million after-taxes ($350 million to $550 million before taxes). Our estimate may be impacted by additional interpretive guidance that is expected on EITF Issue No. 02-3 as well as the interpretation of SFAS No. 133, as amended.

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 2001 Annual Report on Form 10-K in addition to the financial statements and notes presented in Item 1, Financial Statements, of this Quarterly Report on Form 10-Q.

Included throughout this Management's Discussion and Analysis are terms that are common to our industry:

/d	= per day	Mcf	= thousand cubic feet
Bbl	= barrel	MMcf	= million cubic feet
BBtu	= billion British thermal units	MMDth	= million dekatherms
BBtue	= billion British thermal unit equivalents	MTons	= thousand tons
MBbls	= thousand barrels	MWh	= megawatt hours
MMBtu	= million British thermal units		

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.

Liquidity and Capital Resources

Recent Developments

Market Conditions

Since the fourth quarter of 2001, a number of developments in our businesses and industry have significantly impacted our operations and liquidity. These have included:

- The bankruptcy of Enron Corp. and the resulting decline in the energy trading industry;
- The modification of credit standards by the rating agencies; and
- Regulatory and political pressure arising out of the California energy crisis of 2001.

Prior to its bankruptcy in December 2001, Enron was the largest trader of wholesale natural gas and power in the United States and was a significant competitor and counterparty of ours in these markets. Its bankruptcy immediately impacted the liquidity in the wholesale energy markets, removing a substantial trading partner for us and all other energy traders. The effects of the bankruptcy filing and the resulting impact on the industry were immediate and sustained, impacting our ability to enter into both short and long-term wholesale energy trades and our collective ability to convert our existing market positions with Enron into cash. In response, the credit rating agencies, Moody's and Standard and Poor's, re-evaluated the credit ratings of companies involved in energy trading activities, and the credit ratings of most of the largest participants in the energy trading industry have been downgraded to below investment grade and some have experienced significant financial distress. In September 2002, Moody's downgraded our senior unsecured debt from Baa2 to Baa3 (their lowest "investment grade" rating) and has kept us under review for possible further downgrade. In November 2002, Standard and Poor's downgraded our senior unsecured debt from BBB to BBB- (their lowest "investment grade" rating), and we remain on negative credit watch. The rating agencies also lowered our commercial paper rating which resulted in the commercial paper markets currently being unavailable to us at attractive prices.

Maintaining a strong credit rating is critical to our ability to conduct business. Most traders enter into transactions on a margin basis, which means that the actual cash deposited with the purchaser or seller to the transaction is a fraction of the funds that will actually be exchanged at the time settlement occurs. When a company's credit rating falls below investment grade additional cash is required to support these transactions. In addition, many of our financial guarantees, purchase obligations and other commercial commitments and contracts could be negatively impacted by lower credit ratings. As a result, if our rating were lowered to "below investment grade," it could result in immediate additional collateral demands on us.

California Capacity

As discussed in Item 1, Financial Statements, Note 13, *Commitments and Contingencies,* in September 2002, EPNG received an initial decision from a FERC ALJ related to whether EPNG exercised market power with regard to its pipeline capacity to the California border during the latter part of 2000 and the early part of 2001. In that decision, the ALJ held that EPNG withheld capacity from California. We believe the ALJ's ruling is incorrect as a matter of fact, law and policy. We believe that EPNG has consistently demonstrated that it operates its system in a manner to maximize the flow of gas at all times consistent with safety, reliability and operational considerations, and that volume differences during the period in question (November 1, 2000 to March 31, 2001) have been fully explained on the record. The ALJ's decision had an immediate negative impact on our stock price and the market value of our debt, and apparently influenced the rating downgrade by Moody's and more recently the rating downgrade by Standard and Poor's, each discussed above. Despite our position that the ALJ's ruling is incorrect as a matter of fact, law and policy, should the FERC uphold the ALJ's decision, and should we not prevail in our appeal of that decision, the long-term impact on our credit rating, liquidity and our ability to raise capital to meet our ongoing and future investing and financing needs could be substantial depending on the remedy the FERC may seek to impose and the impact the decision could have on our pending state court litigation.

Response and Outlook

In December 2001, in response to industry developments, we announced a plan to enhance our liquidity and strengthen our capital structure. In May 2002, we also announced a plan to limit our investment in, and exposure to, energy trading and to focus our activities and investments in our core natural gas business. Under these plans, we have announced and accomplished the following:

Announced Action	Achievement
Raise cash through equity issuances	Completed over $2.4 billion of equity financings (including proceeds from our equity security units) since December 2001.
Sell non-core assets	Completed or announced over $3.3 billion of asset sales to date.
Remove rating triggers on our Chaparral and Gemstone investments and on our Trinity River and Clydesdale financing transactions	Removed over $4 billion of rating triggers from our investment and financing programs.
Reduce annual operating costs	Reduced annual operating costs in Merchant Energy and the rest of the Company by an estimated $300 million.
Limit our investment in trading	Reduced the net assets in trading from $1.3 billion as of December 31, 2001, to $1 billion as of September 30, 2002.

On November 8, 2002, we announced our intention to exit the trading business. Our actions were prompted by the continued liquidity demands on that business and our desire to eliminate some of the potential demands on our cash flow. Our actions are discussed more fully under our Results of Operations section under our Merchant Energy Segment discussion. Our future goals are to continue to improve our financial position through the additional payoff of debt and other financing instruments, and we will accomplish these actions primarily through the use of operating cash flows, additional asset sales and executing the trading exit strategy discussed above. The actual assets sold will depend on a number of factors, including short-term market developments, the availability of qualified buyers and the acceptability of offers received. In addition, since we are operating in a short timeframe to sell assets, losses and write-downs of the assets we sell could occur.

For the fourth quarter of 2002, our capital needs and liquidity requirements will be significant. Our anticipated cash requirements and estimated funding are as follows:

	Fourth Quarter 2002
	(In millions)
Capital requirements and liquidity needs	
Estimated capital expenditures	$ 925
Debt and financing maturities	242
Dividends	
Preferred securities of subsidiaries	40
Common stock	128
Total capital requirements and liquidity needs	$1,335

For 2003, our debt, financing and minority interest maturities are approximately $2.1 billion, including an assumed $1 billion related to amounts we may be required to pay in connection with our Chaparral guarantee that may occur during the first quarter of 2003. See Segment Results under Merchant Energy for a further discussion of Chaparral.

We anticipate that we will meet our cash needs and liquidity requirements through a combination of cash on hand, cash generated from operations and proceeds from the sale of assets. As of September 30, 2002, our available sources of funds included (in millions):

Cash and cash equivalents	$1,693
Availability under our revolving lines of credit	3,500
Total available sources of funding	$5,193

Our anticipated requirements may change significantly, and our analysis is intended to provide you with a better understanding of our cash needs, both required and discretionary, to better understand our liquidity outlook. Factors that could impact our ability to meet our estimated cash needs include maintaining an investment grade credit rating, our ability to market assets for reasonable prices and in a timely manner and our ability to prevail in the regulatory and legal matters currently pending against us.

Overview of Cash Flow Activities for the Nine Months Ended September 30, 2002

During the nine months ended September 30, 2002, our cash and cash equivalents increased by $0.5 billion to approximately $1.7 billion. During the period, we generated an estimated $6.9 billion through a combination of cash from operations (income before non-cash income items) of $1.6 billion and the net issuance of a combination of long-term debt and equity securities of $5.3 billion. In addition, we generated approximately $1.6 billion through sales of assets and investments, primarily natural gas and oil properties and midstream assets. With the cash we received from these sources, we invested approximately $2.7 billion in fixed assets and equity investments, paid $2.0 billion on maturing long-term debt, paid $1.2 billion, net, on short-term debt, paid $0.3 billion in dividends, and $0.5 billion on minority and preferred interest payments. For the remainder of 2002, we expect to meet our cash investing and financing needs, including the payment of dividends, through cash generated from earnings in our operating businesses and asset sales. However, our working capital inflows or outflows for the remainder of 2002 will be dependent on a number of items not within our control, including operating results, fluctuations in commodity prices, strategies we may implement to offset the impact of commodity price fluctuations and the impact on our credit requirements of ratings actions. Movements in commodity prices can significantly impact our operating cash flow from period to period, either positively or negatively.

For the nine months ended September 30, 2002 and 2001, our cash flows were as follows:

	September 30, 2002	September 30, 2001
	(In millions)	
Net income (loss)	$ 269	$ (282)
Non-cash income adjustments	1,334	2,458
Income before working capital and non-working capital changes	1,603	2,176
Working capital changes	(51)	1,636
Non-working capital changes and other	(393)	(336)
Cash flow from operating activities	1,159	3,476
Cash flow from investing activities	(1,383)	(3,418)
Cash flow from financing activities	779	(22)
Change in cash	$ 555	$ 36

Cash From Operating Activities

Net cash provided by operating activities was $1.2 billion for the nine months ended September 30, 2002, compared to net cash provided by operating activities of $3.5 billion for the same period in 2001. The $2.3 billion decrease was due to a combination of lower income, as adjusted for non-cash income items, of $0.6 billion in 2002 versus 2001 and a use of working capital of $0.1 billion in 2002 compared to cash generated of $1.6 billion last year. The decrease in income as adjusted for non-cash income items in the first nine months of 2002 was due to lower earnings from our merchant and production businesses. For a further discussion of our operating results in these segments, see our discussion of Segment Results below.

The cash generated from working capital last year was primarily attributable to $1.2 billion generated from the liquidation of trading assets and $0.2 billion of margins collected from trading and hedge counterparties. The use of working capital in 2002 was primarily due to $0.4 billion of margin deposits we have with our trading and hedging counterparties offset by $0.4 billion generated from the liquidation of trading assets.

Cash From Investing Activities

Net cash used in our investing activities was $1.4 billion for the nine months ended September 30, 2002. Our investing activities consisted primarily of capital expenditures and equity investments of $2.7 billion offset by net proceeds from sale of assets and investments of $1.6 billion. Our capital expenditures and equity investments included the following (in billions):

Production development, expansion and maintenance projects	$1.6
Pipeline expansion, maintenance and integrity projects	0.6
Investments in unconsolidated affiliates	0.1
Other (primarily petroleum and power projects)	0.4
Total capital expenditures and equity investments	$2.7

Our asset sales proceeds are primarily attributable to the sale of natural gas and oil properties in Texas and Colorado for $0.8 billion, the sale of Texas and New Mexico midstream assets to El Paso Energy Partners for $0.5 billion, and the sale of other power, petroleum and processing assets of $0.3 billion.

Cash From Financing Activities

Net cash provided by our financing activities was $779 million for the nine months ended September 30, 2002. Cash provided from our financing activities included the net issuance of long-term debt of $4.3 billion and issuances of common stock of $1 billion. Cash used by our financing activities included payments made to retire long-term debt and other financing obligations of $2 billion, as well as net repayments under our commercial paper and short-term credit facilities of $1.1 billion. We also repurchased $350 million of preferred securities previously issued by our subsidiaries and made other minority interest payments of $161 million, primarily to

Chaparral which holds a 16 percent minority interest in the utility contract funding project. Further, we made a net repayment of $586 million of notes payable and paid dividends of $340 million.

On November 7, 2002, we declared a quarterly dividend of $0.2175 per share on our common stock, payable on January 6, 2003, to stockholders of record on December 6, 2002. Also, during the nine months ended September 30, 2002, El Paso Tennessee Pipeline Co., our subsidiary, paid dividends of approximately $19 million on our Series A cumulative preferred stock, which is 8¼% per annum (2.0625% per quarter).

Financing and Commitments

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 which are referred to above under cash from financing activities.

Issuances

Date	Company	Type	Interest Rate	Principal	Net Proceeds(1)	Due Date
				(In millions)		
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(2)	Senior secured notes	7.75%	92	90	2008
May	El Paso	Euro notes	7.125%	494(3)	447	2009
June	El Paso	Senior notes(4)	6.14%	575	558	2007
June	El Paso	Notes(5)	7.875%	500	494	2012
June	EPNG	Notes(5)	8.375%	300	297	2032
June	TGP	Notes	8.375%	240	237	2032
July	Utility Contract Funding(2)	Senior secured notes	7.944%	829	786	2016

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

(2) These notes are collateralized solely by the cash flows and contracts of these consolidated subsidiaries, and are non-recourse to other El Paso companies. The Mohawk River Funding IV financing relates to our Capitol District Energy Center Cogeneration Associates restructuring transaction, and the Utility Contract Funding financing relates to our Eagle Point Cogeneration restructuring transaction.

(3) Represents the U.S. dollar equivalent of 500 million Euros at September 30, 2002, and includes a $44 million change in value due to a change in the Euro to U.S. dollar foreign currency exchange rate from the issuance date to September 30, 2002.

(4) These senior notes relate to an offering of 11.5 million 9% equity security units, which include forward purchase contracts on El Paso common stock to be settled on August 16, 2005.

(5) We have committed to exchange these notes for new registered notes. The form and terms of the new notes will be identical in all material respects to the form and terms of these old notes except that the new notes (1) will be registered with the Securities and Exchange Commission, (2) will not be subject to transfer restrictions and (3) will not be subject, under certain circumstances, to an increase in the stated interest rate.

Retirements

Date	Company	Type	Interest Rate	Principal	Net Payments	Due Date
				(In millions)		
2002						
January	SNG	Long-term debt	7.85%	$ 100	$ 100	2002
January	EPNG	Long-term debt	7.75%	215	215	2002
March	El Paso CGP	Long-term debt	Variable	400	400	2002
April	El Paso	Long-term debt	8.78%	25	25	2002
May	SNG	Long-term debt	8.625%	100	100	2002
June	El Paso CGP	Crude oil prepayment	Variable	300	300	2002
June	El Paso CGP	Long-term debt	Variable	90	90	2002
Jan.-June	El Paso Production	Natural gas production payment	LIBOR+ 0.372%	216	216	2002-2005
July	El Paso CGP	Long-term debt	Variable	55	55	2002
July-Aug.	El Paso(1)	Long-term debt	7.00%	30	22	2011
July-Aug.	El Paso(1)	Long-term debt	7.875%	35	27	2012
August	El Paso(1)	Long-term debt	6.75%-7.625%	19	15	2005-2011
August	El Paso CGP(1)	Long-term debt	6.20%	10	9	2004
August	El Paso CGP	Long-term debt	6.625%	460	25(2)	2004
June-Aug.	El Paso CGP	Long-term debt	Variable	51	51	2010-2028
September	El Paso CGP	Long-term debt	8.125%	250	250	2002
Jan.-Sep.	El Paso CGP	Long-term debt	Variable	106	106	2002
Jan.-Sep.	Various	Long-term debt	Various	32	32	2002
October	El Paso Tennessee	Long-term debt	7.875%	12	12	2002
Oct.-Nov.	El Paso CGP	Crude oil prepayment	Variable	133	133	2002
Oct.-Nov.	El Paso	Long-term debt	Various	12	12	2002
November	El Paso CGP	Long-term debt	Variable	60	60	2002

(1) These amounts represent a buyback of our bonds in the open market in July and August 2002.

(2) The majority of this debt was exchanged for equity. See Item 1, Financial Statements, Note 14 for a further discussion of this transactions.

In June 2002, we issued 51.8 million shares of our common stock at a public offering price of $19.95 per share. Net proceeds from the offering were approximately $1 billion and was used to repay short-term borrowings and other financing obligations and for general corporate purposes.

In July 2002, Utility Contract Funding issued $829 million of 7.944% senior secured notes due in 2016. This financing is non-recourse to other El Paso companies, as it is independently supported only by the cash flows and contracts of Utility Contract Funding including obligations of Public Service Electric and Gas under a restructured power contract and of Morgan Stanley under a power supply agreement. In connection with the credit enhancement provided by Morgan Stanley's participation, we paid them $36 million in consideration for entering into the supply agreement in addition to their underwriting fee of $6 million. We believe the benefits to us of Morgan Stanley's participation exceed the cost paid to them. The proceeds from the debt issuance were used to pay off the costs of the restructuring transaction and for general corporate purposes.

In July 2002, we entered into two cross-currency swap transactions which effectively hedged €400 million of our euro currency risk on our €500 million Euro-denominated debt. In the first transaction, €250 million of our 7.125% fixed rate was swapped for $252.5 million of floating rate debt at a rate of the six-month LIBOR plus a spread of 2.195%. A second transaction swapped €150 million of our 7.125% fixed rate euro based debt for $151.5 million, 7.08% fixed dollar based debt.

In August 2002, we issued 12,184,444 shares of common stock to satisfy purchase contract obligations under our FELINE PRIDES[SM] program. In return for the issuance of the stock, we received approximately $25 million in cash from the maturity of a zero coupon bond and the return of $435 million of our existing 6.625% senior debentures due August 2004 that were issued in 1999. The zero coupon bond and the senior debentures had been held as collateral for the purchase contract obligations. The $25 million received from the maturity of the zero coupon bond was used to retire additional senior debentures. Total debt reduction from the issuance of the common stock was approximately $460 million.

Credit Facilities and Available Capacity

In February 2002, we filed a new shelf registration statement with the SEC 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 two wholly-owned trusts, El Paso Capital Trust II and El Paso Capital Trust III. If we issue securities from these trusts, we will be required to issue full and unconditional guarantees on these securities. As of September 30, 2002, we had $818 million remaining capacity under this shelf registration statement.

In May 2002, we renewed our $3 billion, 364-day revolving credit and competitive advance facility. EPNG and TGP, our subsidiaries, remain designated borrowers under this facility and, as such, are liable for any amounts outstanding. This facility matures in May 2003. In June 2002, we amended our existing $1 billion, 3-year revolving credit and competitive advance facility to permit us to issue up to $500 million in letters of credit and to adjust pricing terms. This facility matures in August 2003, and El Paso CGP, EPNG and TGP are designated borrowers under this facility and, as such, are liable for any amounts outstanding. The interest rate under both of these facilities varies based on our senior unsecured debt rating, and as of September 30, 2002, an initial draw would have had a rate of LIBOR plus 0.625%, plus a 0.25% utilization fee for drawn amounts above 25% of the committed amounts. As of September 30, 2002, there were no borrowings outstanding; however, we have issued $492 million of letters of credit under the $1 billion facility.

In September 2002, Moody's lowered our senior unsecured debt rating from Baa2 to Baa3 and in November 2002, Standard and Poor's lowered our senior unsecured debt rating from BBB to BBB-. As a result of these events, the current interest rate on an initial draw under both of the facilities would be at a rate of LIBOR plus 0.80%, plus a 0.25% utilization fee for drawn amounts above 25% of the committed amounts.

Restrictive Covenants

We and our subsidiaries have entered into debt instruments and guaranty agreements that contain covenants such as restrictions on debt levels, restrictions on liens securing debt and guarantees, restrictions on mergers and on the sales of assets, capitalization requirements, dividend restrictions and cross-payment default and cross-acceleration provisions. A breach of any of these covenants could result in acceleration of our debt and other financial obligations and that of our subsidiaries.

Under our revolving credit facilities, the significant debt covenants and cross defaults are:

(a) the ratio of consolidated debt and guarantees (excluding certain project financing and securitization programs and other miscellaneous items) to capitalization cannot exceed 70 percent;

(b) the consolidated debt and guarantees (other than excluded items) of our subsidiaries cannot exceed the greater of $600 million or 10 percent of our consolidated net worth;

(c) we or our principal subsidiaries cannot permit liens on the equity interest in our principal subsidiaries or create liens on assets material to our consolidated operations securing debt and guarantees (other than excluded items) exceeding the greater of $300 million or 10 percent of our consolidated net worth, subject to certain permitted exceptions; and

(d) the occurrence of an event of default for any non-payment of principal, interest or premium with respect to debt (other than excluded items) in an aggregate principal amount of

$200 million or more; or the occurrence of any other event of default with respect to such debt that results in the acceleration thereof.

We were in compliance with the above covenants as of the date of this filing, and no borrowings were outstanding under our revolving credit facilities; however, we have issued $492 million of letters of credit under the $1 billion facility.

We have also issued various guarantees securing financial obligations of our subsidiaries and unconsolidated affiliates with similar covenants as in the above credit facilities.

With respect to guarantees issued by our subsidiaries, the most significant debt covenant, in addition to the covenants discussed above, is that El Paso CGP must maintain a minimum net worth of $1.2 billion. If breached, the amounts guaranteed by the guaranty agreements could be accelerated. The guaranty agreements also maintain a $30 million cross-acceleration provision.

In addition, three of our subsidiaries have indentures associated with their public debt that contain $5 million cross-acceleration provisions.

Notes Payable to Affiliates

Our notes payable to unconsolidated affiliates as of September 30, 2002, were $373 million versus $872 million as of December 31, 2001. The decrease is primarily due to the partial repayment of Gemstone and Chaparral debt securities.

Minority and Preferred Interests of Consolidated Subsidiaries

The total amount outstanding for securities of subsidiaries and preferred stock of consolidated subsidiaries was $3,728 million at September 30, 2002, versus $4,013 million at December 31, 2001. The decrease was due primarily to our repurchase from unaffiliated investors of 50,000 preferred units in El Paso Oil & Gas Resources Company, L.P. and 150,000 preferred shares in Coastal Limited Ventures, Inc. wholly owned subsidiaries, for $65 million plus accrued and unpaid dividends in July 2002. We also reacquired the limited partnership interest, in El Paso Production Oil & Gas Associates, L.P., a partnership formed with Coastal Limited Ventures, Inc. The payment of approximately $285 million was equal to the sum of the limited partner's outstanding capital plus unpaid priority returns. We also made payments to minority interest holders, primarily Chaparral, of $161 million. The decrease was partially offset by the consolidation of our Eagle Point Cogeneration Partnership and our Capitol District Energy Center Cogeneration Associates investments in January 2002 and subsequent contributions, which increased minority interest by $170 million. For the nine months ended September 30, 2002, we recorded $55 million of minority interest expense.

Lines of Credit

As of September 30, 2002, Mesquite had $698 million outstanding under a credit facility at an interest rate of 2.3%. We anticipate Mesquite will repay approximately $300 million of the amounts due under this facility during the fourth quarter with cash generated primarily from its sale of investments in two power plants that were completed in November of 2002, net proceeds from completion of a power restructuring that is also expected to close during the fourth quarter of 2002 and operating cash flows.

Letters of Credit

As of September 30, 2002, we had outstanding letters of credit of approximately $1 billion versus $465 million as of December 31, 2001. The increase is primarily due to the issuance of letters of credit in connection with the management of our trading operations.

Other Commercial Commitments

In 2001, our subsidiaries entered into agreements to time-charter four separate ships to secure transportation for our developing LNG business. In May 2002, we entered into amendments to three of the initial four time charters to reconfigure the ships with onboard regasification technology and to secure an option for an additional time charter for a fifth ship. The exercise of the option for the fifth ship will represent a commitment of $522 million over the term of such charter. However, we are obligated to pay a termination fee of $24 million in the event the option is not exercised by April 2003. The agreements provide for deliveries of vessels between 2003 and 2005. Each time charter has a twenty-year term commencing when the vessels are delivered with the possibility of two five-year extensions. The total commitment of our subsidiaries under the five time-charter agreements is approximately $2.5 billion over the term of the time charters. If our subsidiaries were unable to fulfill their obligations under the five time charter arrangements, our maximum commitment, in the form of corporate guarantees and letters of credit, would be $254 million, which will increase to $290 million if we exercise the option for the time charter on the fifth ship. We are party to an agreement with an unaffiliated global integrated oil and gas company under which the third party agrees to bear 50 percent of the risk incidental to the initial $1.8 billion commitment made for the first four time charters.

Segment Results

Our four segments: Pipelines, Production, Merchant Energy 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 use earnings before interest expense and income taxes (EBIT) to assess the operating results and effectiveness of our business segments. We define EBIT as operating income, adjusted for several items, including:

- equity earnings from unconsolidated investments;
- minority interests on consolidated, but less than wholly-owned operating subsidiaries;
- gains and losses on sales of assets; and
- other miscellaneous non-operating items.

Items that are not included in this measure are:

- financing costs, including interest and debt expense and returns on preferred interests of consolidated subsidiaries;
- income taxes;
- discontinued operations;
- extraordinary items; and
- the impact of accounting changes.

We believe this measurement is useful to our investors because it allows them to evaluate the effectiveness of our businesses and operations and our investments from an operational perspective, exclusive of the costs to finance those activities and exclusive of income taxes, neither of which are directly relevant to the efficiency of those operations. 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 cash flow. For a further discussion of our individual segments, see Item 1, Financial Statements, Note 12, as well as our 2001 Annual Report on Form 10-K. The segment EBIT results for the periods presented below include the charges discussed above:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
	(In millions)			
Pipelines	$ 302	$274	$1,024	$ 676
Production	179	169	362	643
Merchant Energy	(171)	253	(18)	647
Field Services	(11)	43	94	134
Segment total	299	739	1,462	2,100
Corporate and other	34	(91)	(5)	(1,368)
Consolidated EBIT	$ 333	$648	$1,457	$ 732

Pipelines

Our Pipelines segment includes our interstate transmission businesses. Our interstate transmission systems face varying degrees of competition from other pipelines, as well as alternate energy sources, such as electricity, hydroelectric power, coal and fuel oil. In addition, some of our businesses have shifted from a traditional dependence solely on long-term contracts into a portfolio approach which balances short-term opportunities with long-term commitments. The shift is due to changes in market conditions and competition driven by state utility deregulation, local distribution company mergers, new supply sources, volatility in natural gas prices, demand for short-term capacity and new markets to supply power plants.

We are regulated by the Federal Energy Regulatory Commission. The FERC sets the rates we can recover from our customers. These rates are generally a function of our cost of providing service to our customers, as well as a reasonable return on our invested capital. As a result, our pipeline results have historically been relatively stable. However, they can be subject to volatility due to factors such as weather, changes in natural gas prices, regulatory actions and the creditworthiness of our customers. In addition, our ability to extend our existing contracts or re-market expiring capacity is dependent on the competitive alternatives, regulatory environment and the supply and demand factors at the relevant extension or expiration dates. While every attempt is made to negotiate contract terms at fully-subscribed quantities and at maximum rates allowed under our tariffs, some of our contracts are discounted to meet competition.

As discussed more fully in Item 1, Financial Statements, Note 13, under the subheading *Rates and Regulatory Matters,* in September 2002, EPNG received an initial decision from an ALJ related to whether it exercised market power with regard to its pipeline capacity to the California border during the latter part of 2000 and the early part of 2001. In that decision, the ALJ held that EPNG withheld capacity from California. We believe that holding is incorrect as a matter of fact, law, and policy. We believe that EPNG has consistently demonstrated that it operates its systems in a manner to maximize the flow of gas at all times consistent with safety, reliability, and operational considerations, and that volume differences on EPNG during the period in question (November 1, 2000 to March 31, 2001) have been fully explained on the record. However, despite our position, should the FERC uphold the ALJ's decision, and should we not prevail in our appeal of that decision, the long-term impact on EPNG, and on our segment results could be substantial depending on the remedy the FERC may seek to impose on us and the impact such decision could have on our pending state court litigation.

Also as discussed in Item 1, Financial Statements, Note 13 under the subheading *Rates and Regulatory Matters,* EPNG has an existing FERC order related to the allocation of capacity on its system that requires it to:

- Prospectively give reservation charge credits to its firm shippers if it fails to schedule the shippers' confirmed volumes (except in the case of force majeure);

• Refrain from entering into new firm contracts or remarketing turned back capacity under terminated or expired contracts until May 1, 2003; and

• Add additional compression to its Line 2000 project (up to 320 MMcf/d) without the recovery of these costs in its rates until its next rate case which will be effective in January 1, 2006.

EPNG's and our Pipelines segments' future results of operations will be impacted as a result of both orders in the capacity allocation proceeding and the Enron bankruptcy (discussed below). The September 20 order prohibits EPNG from remarketing approximately 471 MMDth/d of its capacity. Of this amount, approximately 195 MMDth/d is capacity which was rejected by Enron in May 2002 in its bankruptcy proceeding. Prior to the rejection of the contracts, EPNG was earning approximately $1.5 million (net of revenue sharing credits) per month from Enron for this capacity. Because EPNG cannot remarket this capacity, it will experience a loss of revenue due to the relinquishment of this capacity in the bankruptcy proceeding. The amount of such revenue loss cannot be determined because it would depend on the rates it could obtain by remarketing the capacity.

The remaining 276 MMDth/d of capacity that EPNG is unable to remarket as a result of the September 20 order will also cause a reduction in its transportation revenues. This capacity relates to contracts that expire within the time frame specified by the order. Under these contracts, EPNG was earning $2 million (net of revenue sharing credits) per month in revenues prior to their expiration. The amount of revenue loss cannot be determined because, as with the Enron capacity, it would depend on the rates it could obtain by remarketing the capacity. EPNG has requested rehearing of the September 20 FERC Order on this and other aspects of the order. This request for rehearing is pending before the FERC.

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. Enron's subsidiaries had transportation contracts on several of our pipeline systems (including the EPNG contract discussed above). 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, which EPNG is prohibited from remarketing under the capacity allocation orders discussed above. We have fully reserved for the amounts due through the date the contracts were rejected, and we have not recognized any revenues from these contracts since that date.

In October 2002, we announced our intent to sell our 14.4 percent interest in the Alliance pipeline system to Enbridge Inc. We expect to complete this sale during the first quarter of 2003. Income earned on our investment in Alliance for the quarter and nine months ended September 30, 2002, was approximately $5 million and $17 million.

Results of our Pipelines segment operations were as follows:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
	(In millions)			
Operating revenues	$ 609	$ 609	$ 1,941	$ 2,053
Operating expenses	(348)	(372)	(1,061)	(1,491)
Other income	41	37	144	114
EBIT	$ 302	$ 274	$ 1,024	$ 676

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
Throughput volumes (BBtu/d)[1]				
TGP	4,472	4,162	4,498	4,431
EPNG and MPC	4,069	4,550	4,105	4,641
ANR	3,746	3,655	3,710	3,789
CIG and WIC	2,460	2,136	2,558	2,282
SNG	1,927	1,692	1,996	1,859
Equity investments (our ownership share)	2,934	2,688	2,774	2,464
Total throughput	19,608	18,883	19,641	19,466

(1) Throughput volumes 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.

Third Quarter 2002 Compared to Third Quarter 2001

Operating revenues for the quarter ended September 30, 2002, remained flat compared to the same period in 2001. A decrease of $29 million resulted from lower revenues from natural gas sales and from gathering and processing activities due to the sale of CIG's Panhandle field on July 1, 2002. Also contributing to the decrease were $7 million from a FERC order which disallowed the remarketing of the EPNG capacity rejected by Enron and $3 million from lower throughput due to lower electric generation demand and milder weather in 2002. These decreases were offset by an increase of $15 million due largely to transmission system expansion projects placed in service in 2001 and 2002, a $14 million favorable resolution of measurement issues at a processing plant serving the TGP system in 2002, $8 million from the Elba Island LNG facility which was placed in service in December 2001, and $4 million of additional revenues from the South System I (Phase 1) expansion, which was placed in service in June 2002.

Operating expenses for the quarter ended September 30, 2002, were $24 million lower than the same period in 2001. The decrease was due to price changes on natural gas imbalances of $15 million and $14 million decrease related to the sale of CIG's Panhandle field on July 1, 2002. Also contributing to the decrease were lower amortization of goodwill of $5 million due to the implementation of SFAS No. 142 in 2002 and $3 million from lower compressor operating costs in 2002 on the EPNG system resulting from lower electric usage and prices. These decreases were partially offset by an increase of $5 million in estimated legal liabilities in 2002, higher amortization of additional acquisition costs assigned to utility plant of $3 million in 2002, higher operating expenses of $3 million due to the Elba Island LNG facility being in service in 2002 and higher corporate overhead allocations in 2002 of $2 million.

Other income for the quarter ended September 30, 2002, was $4 million higher than the same period in 2001 primarily due to the resolution of uncertainties associated with the sale of our interests in the Gulfstream pipeline project in 2001.

Nine Months Ended 2002 Compared to Nine Months Ended 2001

Operating revenues for the nine months ended September 30, 2002, were $112 million lower than the same period in 2001. The decrease was due to lower natural gas and liquids sales of $51 million resulting from lower prices in 2002 and $50 million due to the impact of lower prices in 2002 on natural gas recovered in excess of the amounts used in operations. Also contributing to the decrease were lower revenues of $29 million from natural gas sales and from gathering and processing activities due to the sale of CIG's Panhandle field on July 1, 2002, lower transportation revenues of $22 million from capacity sold under short-term contracts and milder winter weather and $15 million from lower throughput due to lower electric generation demand and milder winter weather in 2002. In addition, an $11 million decrease in operating revenues was due to favorable resolution of regulatory issues related to natural gas purchase contracts in 2001, a $6 million decrease was due to lower rates on the Mojave Pipeline System as a result of a rate case settlement effective October 2001, and a $6 million decrease due to the sale of our Midwestern Gas Transmission system in April 2001. These decreases were partially offset by $34 million additional reservation revenues due largely to transmission system expansion projects placed in service in 2001 and 2002, $25 million due to a larger portion of EPNG's capacity sold at maximum tariff rates in 2002, $22 million from the Elba Island LNG facility placed in service in December 2001, $18 million from the favorable resolution of measurement issues at a processing plant serving the TGP system in 2002 and $4 million from the South System I (Phase 1) expansion placed in service in June 2002.

Operating expenses for the nine months ended September 30, 2002, were $430 million lower than the same period in 2001 primarily as a result of 2001 merger-related costs of $316 million due to our merger with Coastal. For a discussion of these costs, see Item 1, Financial Statements, Note 4. Also contributing to the decrease were $43 million from lower fuel and system supply purchases costs resulting from lower natural gas volumes and prices in 2002, $19 million from the impact of price changes on natural gas imbalances, $17 million due to lower employee benefit costs and lower operating expenses in 2002 due to cost efficiencies following the merger with Coastal, a 2001 change in estimate of $18 million primarily for additional environmental remediation liabilities, lower amortization of goodwill of $14 million due to the implementation of SFAS No. 142 in 2002, $14 million decrease related to the sale of CIG's Panhandle field on July 1, 2002, $13 million lower corporate overhead allocations in 2002 and $10 million from lower compressor operating costs in 2002 on the EPNG system resulting from lower electric usage and prices. These decreases were partially offset by an increase of $14 million to our reserve for bad debts in 2002 related to the bankruptcy of Enron Corp., additional accruals of $13 million in 2002 on estimated liabilities to assess and remediate our environmental exposure due to an ongoing evaluation of our operating facilities, an increase of $10 million in estimated legal liabilities in 2002, higher amortization of additional acquisition costs assigned to a utility plant of $10 million in 2002 and higher operating expenses of $9 million due to the Elba Island LNG facility returned to service in 2002.

Other income for the nine months ended September 30, 2002, was $30 million higher than the same period in 2001. An increase of $11 million was due to a gain on the sale of pipeline expansion rights in February 2002, and $11 million due to the resolution of uncertainties associated with the sales of our interests in the Empire State, Iroquois pipeline systems, and our Gulfstream pipeline project in 2001. Also contributing to the increase were higher equity earnings in 2002 of $10 million primarily due to our investment in Great Lakes Gas Transmission. These increases were partially offset by lower equity earnings of $6 million on Empire State and Iroquois pipeline systems due to the sale of our interests in 2001.

Production

The 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.

In the past, our stated goal was to hedge approximately 75 percent of our anticipated current year production, approximately 50 percent of our anticipated succeeding year production and a lesser percentage thereafter. As a component of our strategic repositioning plan in May 2002, we modified this hedging strategy. We now expect to hedge approximately 50 percent or less of our anticipated production for a rolling 12-month forward period. This modification of our hedging strategy will increase our exposure to changes in commodity prices which could result in significant volatility in our reported results of operations, financial position and cash flows from period to period. We have hedged approximately 50 percent of our expected natural gas production for the fourth quarter of 2002 at a NYMEX price of $3.92 per MMBtu before regional price differentials and transportation costs. We have hedged approximately 217 million MMbtu's of our anticipated natural gas production for 2003 at a NYMEX price of $3.43 per MMBtu before regional price differentials and transportation costs.

During 2002, we have continued an active onshore and offshore development drilling program to capitalize on our land and seismic holdings. This development drilling is done to take advantage of our large inventory of drilling prospects and to develop our proved undeveloped reserve base. We have also completed asset dispositions in Colorado and Texas as part of our balance sheet enhancement plan. As a result of our asset dispositions, we will likely have a lower reserve base at January 1, 2003 than we did at January 1, 2002. Since our depletion rate is determined under the full cost method of accounting, a lower reserve base coupled with additional capital expenditures in the full cost pool will result in higher depletion expense in future periods. For the fourth quarter of 2002, we expect our unit of production depletion rate to be approximately $1.40 per equivalent unit.

Our total estimated capital expenditures in 2002 are approximately $2.3 billion. Based on our current level of capital expenditures, our asset dispositions, and our production decline rates, we expect our total 2002 equivalent production volumes to be approximately 8 percent lower than our 2001 equivalent production volumes.

We will continue to pursue strategic acquisitions of production properties and the development of projects subject to acceptable returns. In July 2002, we acquired natural gas properties in the Raton Basin for approximately $140 million. These properties were acquired to expand the interest in our current coal seam project in the area.

Below are the operating results and an analysis of these results for the periods ended September 30:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
	(In millions, except volumes and prices)			
Natural gas	$ 403	$ 523	$ 1,324	$ 1,504
Oil, condensate and liquids	92	80	289	246
Other	4	6	(4)	18
Total operating revenues	499	609	1,609	1,768
Transportation and net product costs	(29)	(19)	(84)	(75)
Total operating margin	470	590	1,525	1,693
Operating expenses(1)	(290)	(422)	(1,168)	(1,051)
Other income	(1)	1	5	1
EBIT	$ 179	$ 169	$ 362	$ 643
Volumes and prices				
Natural gas				
Volumes (MMcf)	120,092	146,366	373,378	419,587
Average realized prices(2) ($/Mcf)	$ 3.21	$ 3.46	$ 3.37	$ 3.48
Oil, condensate and liquids				
Volumes (MBbls)	3,986	3,562	13,940	10,049
Average realized prices(2) ($/Bbl)	$ 22.19	$ 21.62	$ 19.84	$ 23.88

(1) Includes production costs, depletion, depreciation and amortization, ceiling test charges, merger-related costs, changes in accounting estimates, corporate overhead, general and administrative expenses and other taxes.

(2) Net of transportation costs.

Third Quarter 2002 Compared to Third Quarter 2001

For the quarter ended September 30, 2002, operating revenues were $110 million lower than the same period in 2001. An 18 percent decrease in natural gas volumes and a 6 percent decrease in natural gas prices, before transportation costs, contributed to $120 million of the decrease in revenues. The decline in natural gas volumes is primarily attributable to the sale of properties in Texas and Colorado and the impact of several South Texas wells that were shut-in during part of the quarter. The decrease in revenues is partially offset by a 12 percent increase in oil, condensate and liquids volumes, and a 3 percent increase in their prices before transportation costs, resulting in a $12 million increase in revenues. Further, a gain of approximately $6 million was recognized in the third quarter of 2002 due to a mark-to-market adjustment of derivative positions that no longer qualify as cash flow hedges under SFAS No. 133. These hedges no longer qualify for hedge accounting treatment since they were designated as hedges of anticipated future production from natural gas and oil properties that were sold in March 2002.

Transportation and net product costs for the quarter ended September 30, 2002, were $10 million higher than the same period in 2001 primarily due to a higher percentage of gas volumes subject to transportation fees and costs incurred to meet minimum payments on pipeline agreements.

Operating expenses for the quarter ended September 30, 2002, were $132 million lower than the same period in 2001. Contributing to the decrease in expenses were non-cash full cost ceiling test charges totaling $135 million for international properties incurred in the third quarter of 2001. A $12 million decrease in severance and other taxes in 2002 resulted in an additional decrease to total expenses. Offsetting these decreases in 2002 were higher overhead corporate allocations of $11 million and higher depletion expense of $5 million as a result of additional capital spending on assets in the full cost pool.

Nine Months Ended 2002 Compared to Nine Months Ended 2001

For the nine months ended September 30, 2002, operating revenues were $159 million lower than the same period in 2001. An 11 percent decrease in natural gas volumes and a 1 percent decrease in natural gas prices, before transportation costs, contributed to $180 million of the decrease in revenues. The decline in natural gas volumes is primarily attributed to the sale of properties in Texas and Colorado. The decrease in revenue is partially offset due to a 39 percent increase in oil, condensate and liquids volumes offset by a 15 percent decrease in their prices, before transportation costs, resulting in a $43 million increase in revenues. Further decreasing revenues was a loss of $10 million in 2002 resulting from a mark-to-market adjustment of derivative positions that no longer qualify as cash flow hedges under SFAS No. 133. These hedges no longer qualify for hedge accounting treatment since they were designated as hedges of anticipated future production from natural gas and oil properties that were sold in March 2002.

Transportation and net product costs for the nine months ended September 30, 2002, were $9 million higher than the same period in 2001 primarily due to a higher percentage of gas volumes subject to transportation fees and costs incurred to meet minimum payments on pipeline agreements.

Operating expenses for the nine months ended September 30, 2002, were $117 million higher than the same period in 2001. Contributing to the increase in expenses were non-cash full cost ceiling test charges totaling $267 million incurred in 2002 for our Canadian full cost pool and other international properties primarily in Brazil, Turkey and Australia, offset by third quarter 2001 non-cash full cost ceiling test charges on international properties totaling $135 million. Also contributing to the increase in 2002 expenses were higher depletion expenses of $79 million resulting from additional capital spending on assets in the full cost pool, increased oilfield service costs of $31 million due primarily to higher labor, workovers and production processing fees and higher corporate overhead allocations of $21 million. Partially offsetting the increase in expenses were merger-related costs and other charges of $63 million incurred in 2001 relating to our combined production operations and $10 million of changes in accounting estimates primarily related to write-downs of materials and supplies resulting from the ongoing evaluation of our operating standards recognized in 2001. For a discussion of merger-related costs, see Item 1, Financial Statements, Note 4. For a discussion of write-downs of materials and supplies, see Item 1, Financial Statements, Note 6, and for a discussion of our ceiling test charge, see Item 1, Financial Statements, Note 5. In addition, the increase in expenses were offset by $73 million of lower severance and other taxes in 2002. The severance taxes decreased primarily because of lower natural gas volumes and prices and for tax credits in 2002 for high cost gas wells.

Other income for the nine months ended September 30, 2002, was $4 million higher than the same period in 2001 primarily due to a gain on the sale of non-full cost pool assets in south and east Texas in March 2002 and higher earnings in 2002 from Pescada, an equity investment in Brazil.

Merchant Energy

Our Merchant Energy segment consists of three primary divisions: domestic and international power, petroleum and LNG and trading and energy-related price risk management activities. In May 2002, we announced a strategic repositioning plan in order to respond to the changing market conditions in the wholesale energy marketing industry. The key elements of our plan in the Merchant Energy segment included:

- downsizing of our trading and risk management activities;
- a reduction of Merchant Energy personnel to achieve $150 million of annualized cost savings; and
- limiting cash working capital investments from trading activities to $1 billion.

Since that time, the energy trading environment has continued to deteriorate as evidenced by the following factors:

- many major participants have exited the industry;
- liquidity in the energy commodity markets has been reduced; and
- increasing credit demands have created uncertainty surrounding margin calls and cash requirements for energy trading companies.

Because of these factors, in November 2002, we decided to exit the energy trading business and pursue an orderly liquidation of our trading portfolio. To do this, we plan to establish a separately capitalized subsidiary to hold the bulk of our trading portfolio and manage its liquidation. We anticipate this liquidation would occur over a period from 18 to 24 months. Once established, we anticipate this subsidiary would have separate credit facilities of up to $600 million. We also expect to support the credit facilities with a pledge of pipeline equity investments (Citrus and Great Lakes). We believe our plan should allow us to obtain an independent investment grade credit rating for the subsidiary, which would minimize much of the uncertainty surrounding our cash needs for potential collateral calls. Our liquidation strategy is intended to achieve the following:

- maximize cash flow from the trading portfolio;
- reduce our risk in an uncertain environment;
- avoid a fire sale of the portfolio in the current distressed environment;
- isolate the credit and liquidity needs of the trading business from the rest of our business; and
- clearly outline our maximum potential investment in the trading business.

Following our decision to exit our energy trading activities, we will continue to focus on other areas of our Merchant Energy segment including our domestic and international power activities and petroleum and LNG activities. In these areas we will concentrate on our core business and growth opportunities while also rationalizing our existing assets in these areas.

Domestic and International Power

Our domestic and international power business includes the ownership and operation of power generating facilities. In most cases, we partially own our power generating facilities and account for them using the equity method. We conduct most of our domestic power business through Chaparral. Internationally, we have invested in the Brazil power market through our equity investment in Gemstone. We also have interests in a number of other project-financed power facilities in Asia, Central America, Europe and Mexico. We also engage in power contract restructuring activities, mostly through our unconsolidated affiliate, Chaparral. However, our restructuring activities may also involve power plants and related assets that are consolidated in our financial statements, as in the case of our Mount Carmel and Eagle Point Cogeneration restructuring transactions that occurred this year and are discussed in our results of operations below.

Chaparral. As discussed in our 2001 Form 10-K, Chaparral (also known as Electron), was formed to obtain lower cost financing to fund our domestic unregulated power generation business. Our indirect ownership is approximately 20 percent and the remaining amount is owned by Limestone Investors, which is controlled by investment affiliates of Credit Suisse First Boston Corporation. Limestone Investors also issued in March 2000, $1 billion of notes collateralized by the assets of Chaparral and Series B Preferred Stock of El Paso that we issued to a trust.

In April 2002, we substituted the Series B Preferred Stock collateral for substantially all of the Limestone notes with an El Paso guarantee. Only a small portion of notes that have the Series B Preferred Stock as collateral remain outstanding. In the event that Chaparral is not able to make payments on the Limestone notes, then the holders of those notes will look to our guarantee for payment as well as to the assets of Chaparral.

The Limestone notes mature in March 2003, at which time we anticipate that we will purchase Limestone Investor's interest in Chaparral. Although we may continue to look for a new joint venture partner, we expect to consolidate Chaparral upon the purchase of Limestone Investors' interest. Chaparral owns approximately 34 power generation facilities. As of September 30, 2002, Chaparral had $1.8 billion of consolidated third party debt. Chaparral's debt is related to specific projects it owns or has interests in, and is recourse solely to those projects. Our total investment in Chaparral at September 30, 2002 was $264 million, but we also had additional net receivables from Chaparral which totaled $753 million, resulting in a total net investment in Chaparral of $1 billion at September 30, 2002.

If we were to purchase Limestone Investors' interest in Chaparral, we would allocate our acquisition cost, represented by the cost to acquire Limestone Investor's equity plus any debt assumed, to the assets and liabilities we acquired based upon their fair values at the date of acquisition. If the fair value of the assets acquired is less than our acquisition cost, we would recognize goodwill for this difference, which we would be required to test for impairment. It is possible that we could incur a charge if the goodwill is determined to be impaired. If fair value is determined to be greater than our purchase price, we would record the assets based upon our acquisition cost. A number of factors, including industry developments, ongoing changes in our business, and changes in energy prices will impact this determination of fair value.

Through November 2002, Chaparral completed the sale of the following assets:

- the Brush power plant for approximately $73 million in October 2002; and
- the ManChief power plant for approximately $127 million in November 2002.

Power Contract Restructuring Activities. Many of our domestic power plants, and the power plants owned by Chaparral, have long-term power sales contracts with regulated utilities that were entered into under the Public Utility Regulatory Policies Act of 1978 (PURPA). The power sold to the utility under these PURPA contracts is required to be delivered from a specified power generation plant at power prices that are usually significantly higher than the cost of power in the wholesale power market. Our cost of generating power at these PURPA power plants is typically higher than the cost we would incur by obtaining the power in the wholesale power market, principally because the PURPA power plants are less efficient than newer power generation facilities.

Typically, in a power contract restructuring, the PURPA power sales contract is amended so that the power sold to the utility does not have to be provided from the specific power plant. Because we are able to buy lower cost power in the wholesale power market, we have the ability to reduce the cost paid by the utility, thereby inducing the utility to enter into the power contract restructuring transaction. Following the contract restructuring, the power plant operates on a merchant basis, which means that it is no longer dedicated to one buyer and will operate only when power prices are high enough to make operations economical. In addition, we may assume, and in the case of Eagle Point Cogeneration we did assume, the business and economic risks of supplying power to the utility to satisfy the delivery requirements under the restructured power contract over its term. When we assume this risk, we manage these obligations by entering into transactions to buy power from third parties that mitigate our risk over the life of the contract. These activities are reflected as part of our trading activities and reduce our exposure to changes in power prices from period to period. Power contract restructurings generally result in a higher return in our power generation business because we can deliver reliable power at lower prices than our cost to generate power at these PURPA power plants. In addition, we can use the restructured contracts as collateral to obtain financing at a cost that is comparable to, or lower than, our existing financing costs. The manner in which we account for these activities is discussed in Item 1, Financial Statements, Note 1, of this Form 10-Q.

Power restructuring transactions are often extensively negotiated and can take a significant amount of time to complete. In addition, there are a limited number of facilities to which the restructuring process applies. Our ability to successfully restructure a power plant's contracts and the future financial benefit of that effort is difficult to determine, and may vary significantly from period to period. Since we began these activities in 1999, we have completed eleven restructuring transactions, including contract terminations, of varying financial significance, and we have additional facilities which we will consider for restructuring in the future.

Petroleum and LNG

We own or have interests in oil refineries, chemical production facilities, petroleum terminalling and marketing operations, and blending and packaging operations for lubricants and automotive products. Our refinery operations are cyclical in nature and sensitive to movements in the price of crude oil. We are currently operating in an environment where the differences in the price of our crude oil input and the resulting products output is so narrow that we are experiencing losses in our refinery operations. This has been compounded at our Aruba facility where we have experienced operational difficulties following a fire at the facility last year. We anticipate that our capacity utilization at Aruba will improve in the fourth quarter of 2002 since we have just completed a maintenance turnaround that is expected to bring the facility back up to full capacity. We are also making significant progress in reducing costs at our petroleum facilities, and we believe that conditions are favorable for improved earnings from our petroleum activities in the future. We will continue to rationalize our assets in this business and evaluate our petroleum activities and their strategic fit with our core natural gas business.

We are also pursuing an LNG strategy that will focus on development of infrastructure and technology that will provide for new supplies of natural gas to meet the growing natural gas demand in North America. We have committed to a time charter for four ships to secure transportation of LNG. Three of the four ships will provide for on board regasification of the LNG. We expect the delivery of these vessels between 2003 and 2005.

In May 2002, we received final approval from the Norwegian and United States governments on an LNG purchase and sale agreement with Snøhvit signed in October 2001 with a consortium of natural gas production companies led by Statoil ASA. This agreement is a derivative under SFAS No. 133, which we are required to record as an asset from price risk management activities on our balance sheet at its fair value. As a result, we recorded a $59 million gain in the second quarter of 2002 to record the initial fair value of this derivative, and recorded an increase in that fair value of $25 million during the third quarter of 2002, for a total fair value of $84 million at September 30, 2002. In October 2002, we entered into an agreement with Statoil ASA to allow Statoil ASA to purchase our share of the LNG purchase and sale agreement for $210 million. Subject to the completion of conditions required by the agreement, we expect to complete this transaction by the end of 2002.

Trading and Energy-Related Price Risk Management Activities

Our trading activities have historically included customer originating and trading activities that allow us, through financial and physical agreements, to capture value arising from fluctuations in commodity prices.

As of September 30, 2002, the net fair value of all of our energy contracts was $1.6 billion. Of this amount, the net fair value of our trading-related energy contracts was approximately $1.0 billion. Our trading activities generated margins (losses) during the nine months ended September 30, 2002 and 2001 totaling ($110) million and $229 million. The following table details the net fair value of our energy contracts (both trading and non-trading) by year of maturity and valuation methodology as of September 30, 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
			(In millions)			
Trading contracts						
Prices actively quoted	$(44)	$ 300	$223	$241	$ (4)	$ 716
Prices based on models and other valuation methods	156	54	4	11	27	252
Total trading contracts, net	112	354	227	252	23	968
Non-trading contracts[1]						
Prices actively quoted	(76)	(103)	26	156	91	94
Prices based on models and other valuation methods	46	92	89	172	107	506
Total non-trading contracts, net	(30)	(11)	115	328	198	600
Total energy contracts	$ 82	$ 343	$342	$580	$221	$1,568

(1) Non-trading energy contracts include derivatives from our power contract restructuring activities of $963 million and derivatives related to our natural gas and oil producing activities of $(363) million. Earnings related to the natural gas and oil producing activities are included in our Production segment results.

A reconciliation of our trading and non-trading energy contracts for the nine months ended September 30, 2002, is as follows:

	Trading	Non-Trading	Total Commodity Based
		(In millions)	
Fair value of contracts outstanding at December 31, 2001	$1,295	$ 459	$1,754
Fair value of contracts settled during the period	(399)	(227)	(626)
Initial recorded value of new contracts[1]	84	991	1,075
Change in fair value of contracts	54	(623)	(569)
Changes in fair value attributable to changes in valuation techniques	(69)	—	(69)
Other	3	—	3
Net change in contracts outstanding during the period	(327)	141	(186)
Fair value of contracts outstanding at September 30, 2002	$ 968	$ 600	$1,568

(1) The initial recorded value of new contracts for trading primarily comes from completing our Snøhvit LNG supply contract in the second quarter of 2002 and for non-trading primarily comes from our Eagle Point Cogeneration restructuring transaction completed in the first quarter of 2002. See the discussion of these transactions under results of operations below.

Included in "Changes in fair value attributable to changes in valuation techniques" in our trading price risk management activities is a first quarter charge of approximately $61 million related to our revised estimate of the fair value of long-term trading positions. Specifically, we have 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 have not recognized gains from the fair value of trading or non-trading positions beyond ten years unless there is clearly demonstrated liquidity in a specific market. Included in "Other" are option premiums and storage capacity transactions.

In addition to the factors impacting our trading business described above, we will adopt the new provisions of EITF Issue No. 02-3 in the fourth quarter of 2002. This Issue has two significant provisions that will impact the fair value of our trading price risk management activities. The first of the provisions requires that we account for all energy-related contracts that do not qualify as derivatives under SFAS No. 133 using the accrual method of accounting, rather than mark-to-market accounting as was previously required under EITF Issue No. 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities*. Following our application of this provision of EITF Issue No. 02-3 we will continue to record our derivative contracts at fair value under SFAS No. 133. The other provision will require that we account for all inventory held by our energy-trading operation at the lower of its cost or fair value, rather than using mark-to-market accounting as was previously allowed under the EITF Issue No. 98-10. Upon adoption we will adjust the fair value of these inventories in our balance sheet to their corresponding cost using an inventory valuation method (such as average cost). The adoption of EITF Issue No. 02-3, in addition to the announced trading exit strategy, may result in a total after-tax charge of approximately $400 million to $600 million ($600 million to $900 million before-tax).

Results of Operations

Below are Merchant Energy's operating results and an analysis of these results for the periods presented:

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
	(In millions, except volume amounts)			
Trading and refining gross margins	$ (12)	$ 380	$ 708	$ 1,259
Operating and other revenues	135	98	541	317
Operating expenses	(366)	(331)	(1,407)	(1,242)
Other income	72	106	140	313
EBIT	$ (171)	$ 253	$ (18)	$ 647
Volumes[(1)]				
Physical				
Natural gas (BBtue/d)	12,425	7,318	13,092	9,150
Power (MMWh)	142,351	61,571	356,853	143,349
Crude oil and refined products (MBbls)	171,929	187,187	547,975	522,958
Financial settlements (BBtue/d)	207,683	231,942	189,139	222,075

(1) Volumes include those traded over-the-counter in our origination and trading activities, as well as those generated or produced at our consolidated power plants and refineries.

Trading and refining gross margins consist of revenues from commodity trading and origination activities less the cost of commodities sold, the impact of power contract restructuring activities and revenues from refineries and chemical plants, less the costs of feedstocks used in the refining and production processes.

Third Quarter 2002 Compared to Third Quarter 2001

For the quarter ended September 30, 2002, trading and refining gross margins were $392 million lower than the same period in 2001 primarily due to a reduction in trading margins of $296 million due to lower price volatility in the natural gas and power markets, loss of option value driven by our decision to manage our portfolio to increase cash flow and a generally weaker trading environment in the third quarter of 2002. Also contributing to the overall decrease in trading and refining margins was a $100 million decrease in refining margins resulting from lower spreads between the sales prices of refined products and underlying feedstock costs and lower throughput at our Aruba refinery. Besides the above factors, trading and refining gross margins also reflected a net decrease of $66 million due to gains on transactions we originated in the third quarter of 2001 associated with transportation, storage and gas supply contracts. These decreases were partially offset by an increase of $25 million in the value of a long-term LNG supply contract with Snøhvit and an increase of $22 million in the value of our net trading price risk management assets and receivables resulting from the improved credit of several of our counterparties in the third quarter of 2002.

Operating and other revenues consist of revenues from domestic and international power generation facilities and investments, including our management fee from Chaparral, and revenues from EnCap and the other financial services businesses. For the quarter ended September 30, 2002, operating and other revenues were $37 million higher than the same period in 2001. The increase was primarily due to revenues of $32 million from domestic and international power facilities that were consolidated in the fourth quarter of 2001 and the first quarter of 2002 and management fees from Chaparral being higher by $9 million in the third quarter of 2002.

Operating expenses for the quarter ended September 30, 2002, were $35 million higher than the same period in 2001. This was due primarily to a $96 million increase in operating expenses, partially offset by a $61 million increase in the third quarter of 2001 primarily for additional estimated environmental remediation liabilities. Contributing to the overall $96 million increase in operating expenses were $19 million of higher expenses resulting from the acquisition and consolidation of international and domestic power-related entities in the fourth quarter of 2001 and the first quarter of 2002 and a $21 million increase in international employee expenses, training program expenses and unscheduled maintenance expenses at our Aruba refinery in the third quarter of 2002. Also contributing to the increase were higher franchise and other taxes of $6 million and a higher allocation of corporate expenses of $8 million in the third quarter of 2002.

Other income for the quarter ended September 30, 2002, was $34 million lower than the same period in 2001 primarily due to marketing, agency and technical services fees of $33 million earned in 2001 related to the development of the Macae power project in Brazil. Also contributing to the decrease were lower equity earnings of $7 million from unconsolidated projects in the third quarter of 2002. Partially offsetting these decreases was a $15 million gain on the sale of our 50 percent interest in a petroleum product terminal in the third quarter of 2002.

Nine Months Ended 2002 Compared to Nine Months Ended 2001

During 2002, we completed power restructurings or contract terminations at our Eagle Point Cogeneration, Mount Carmel and Nejapa power plants. The Eagle Point Cogeneration restructuring transaction, completed in March 2002, was our most significant power restructuring transaction to date.

The Eagle Point restructuring involved several steps. First, we amended the existing PURPA power sales contract with Public Service Electric and Gas (PSEG) to eliminate the requirement that power be delivered specifically from the Eagle Point power plant. This amended contract has fixed prices with stated increases over the 14-year term that range from $85 per MWh to $126 per MWh. We entered into the amended power sales contract through a consolidated subsidiary, Utility Contract Funding, L.L.C. (UCF). UCF was created to hold and execute the terms of the restructured power sales contract, to enter into a supply contract to meet the requirements of the restructured agreement and to monetize the value of these contracts by issuing debt. In keeping with its purpose, UCF entered into a power supply agreement with EPME, our trading company. The terms of the EPME power supply contract were identical to the restructured power contract, with the exception of price, which was set at $37 per MWh over its 14-year term.

For credit enhancement purposes, in anticipation of the financing transaction associated with the restructuring, UCF terminated the EPME supply contract in the second quarter of 2002 and replaced it with a supply contract with a Morgan Stanley affiliate. UCF entered into the Morgan Stanley contract solely for the purpose of reducing the cost of debt UCF would issue. Morgan Stanley then entered into a supply contract with EPME. While the Morgan Stanley contract does not obligate Morgan Stanley to acquire power only from EPME, the net effect of these two transactions is that EPME is obligated to supply power to meet the obligations to PSEG under the restructured power contract.

EPME separately entered into power purchase transactions with a number of third parties to economically hedge its price risk for substantially all of the notional quantity of power supply requirements over the entire term of the supply agreement in accordance with its risk management policies. The time periods between purchase and delivery of power under the third party contracts differ. As a result, there may be variability in future margins. However, since the power market in which these transactions occurred is highly liquid and prices in this market have historically been highly correlated between periods, we do not expect these timing differences to have a significant impact on our ongoing operating results.

As a result of the various steps we have taken to accomplish this restructuring, we have been able to improve the expected margin associated with the original PURPA contract by replacing the high-cost of the power generated from the Eagle Point plant, which had averaged over $75 per MWh, with power that we have purchased in the open market at an average cost of $31 per MWh. We have also shifted the collection and credit risk to a third party over the term of the restructured power sales agreement.

From an accounting standpoint, the actions taken to restructure the contract required us to mark the contract to its fair value under SFAS No. 133. As a result, we recorded non-cash revenue representing the estimated fair value of the derivative contract of approximately $978 million in our first quarter results. We also amended or terminated other ancillary agreements associated with the cogeneration facility, such as gas supply and transportation agreements, a steam contract and existing financing agreements. In the second quarter, we paid $103 million to the utility to terminate the original PURPA contract. Also included in the first quarter results were a $98 million non-cash charge to adjust the Eagle Point Cogeneration plant to fair value based on its new status as a peaking merchant plant and a non-cash charge of $230 million to write off the book value of the original PURPA contract. Based on these amounts, and including closing and other costs, our first quarter results reflected a net benefit from the Eagle Point Cogeneration restructuring transaction of $438 million. The Morgan Stanley and EPME supply contracts are derivatives and must be accounted for at their fair values, with changes in value recorded in earnings. The third party power purchase transactions which were entered into to hedge our price risk associated with the power supply requirements are also accounted for at fair value since they are also derivatives, but the effects of these transactions have not been included in the determination of the restructuring gain since they are included in our trading results. Total operating cash flows from this transaction amounted to approximately $110 million of cash paid to the utility to amend the original contract and other miscellaneous closing costs. In July 2002, UCF completed the restructuring transaction by monetizing the contract with PSEG and issuing $829 million of 7.944% senior notes collateralized solely by the contracts and cash flows of UCF. The proceeds of the monetization are reported as financing cash flow.

We also employed the principles of our power restructuring business in completing two contract terminations in the nine month period — the Nejapa transaction in the second quarter, and the Mount Carmel transaction in the first quarter. In March 2002, an arbitration award panel approved the termination of the power purchase agreement between Comision Ejecutiva Hydroelectrica del Rio Lempa and the Nejapa Power Company, one of our consolidated subsidiaries, in exchange for a cash payment of $90 million. The award was finalized and paid to Nejapa in the second quarter of 2002. We recorded, as revenue, a $90 million gain and also recorded $13 million in other expense for the minority owner's share of this gain. We applied the proceeds of the award to retire a portion of Nejapa's debt. The Mount Carmel restructuring, which occurred in the first quarter of 2002, involved the termination of the existing PURPA power purchase contract for a fee from the utility of $50 million. In addition, we recorded a non-cash adjustment to reflect fair value of the Mount Carmel facility of $25 million, resulting in a total net benefit on the restructuring transaction of $25 million.

For the nine months ended September 30, 2002, trading and refining gross margins were $551 million lower than the same period in 2001 primarily due to trading margins being lower by $728 million resulting from a lower price volatility in the natural gas and power markets, loss of option value driven by our decision to manage our portfolio to increase cash flow and a generally weaker trading environment in 2002. In addition, we had a $99 million decrease in refining margins due to lower spreads between the sales prices of refined products and underlying feedstock costs and lower throughput at our Eagle Point and Aruba refineries. Also contributing to the decrease in refining gross margins was a decrease of $128 million in marine revenue due to lower freight rates, a decrease in vessels owned and on charter, and lower throughput at our marine terminals, and a decrease of $87 million in refining margins resulting from the lease of our Corpus Christi refinery and related assets to Valero in June 2001. When we leased our refinery to Valero, we began including income from the lease as other income. Besides the above factors, our trading and refining gross margins were affected by transactions we originated and restructuring transactions we completed during 2002. We recorded income of $512 million in the first quarter of 2002 related to the Eagle Point Cogeneration and Mount Carmel power contract restructurings as described above and a $59 million gain in the second quarter of 2002 on the long-term LNG supply contract with Snøhvit. The fair value of the power contract restructurings decreased by $33 million from the initial gains through September 30, 2002, and the fair value of the Snøhvit transaction increased by $25 million from the initial gain through September 30, 2002. In addition, our trading and refining gross margins decreased by $99 million due to gains on transactions we originated in 2001 associated with transportation, storage and gas supply contracts. Offsetting the decrease in trading and refining margins was an increase of $83 million in the value of our net trading price risk management assets and receivables resulting from the improved credit of several of our counterparties in 2002.

For the nine months ended September 30, 2002, operating and other revenues were $224 million higher than the same period in 2001 primarily due to revenues of $132 million from domestic and international power facilities that were consolidated in the fourth quarter of 2001 and the first quarter of 2002, a $90 million gain from the termination of the Nejapa power contract in the second quarter of 2002 and management fees from Chaparral that were higher by $28 million in 2002.

Operating expenses for the nine months ended September 30, 2002, were $165 million higher than the same period in 2001 primarily due to a $342 million impairment of our power investments in Argentina recorded in the first quarter of 2002 (see Item 1, Financial Statements, Note 4) and $81 million of higher expenses resulting from the acquisition and consolidation of international and domestic power-related entities in the fourth quarter of 2001 and the first quarter of 2002. Also contributing to the increase were an allocation of corporate expenses that was higher by $31 million in 2002, a $29 million increase in international employee expenses, training program expenses and unscheduled maintenance expenses at our Aruba refinery in 2002, a $19 million turbine forfeiture fee for a cancelled power project during 2002, and higher franchise and other taxes of $13 million in 2002. These increases were partially offset by merger-related costs and asset impairments of $191 million recorded in 2001 associated with combining operations with Coastal (see Item 1, Financial Statements, Note 4), a $133 million increase in 2001 primarily for additional estimated environmental remediation liabilities and a decrease of $54 million in fuel costs used in our refining operations resulting from lower gas prices and the lease of our Corpus Christi refinery and related assets to Valero in June 2001.

Other income for the nine months ended September 30, 2002, was $173 million lower than the same period in 2001 primarily due to marketing, agency and technical services fees of $73 million from the development of the Macae power project in Brazil earned in 2001, $49 million of Chaparral's minority ownership interest in the initial income earned on our Eagle Point Cogeneration restructuring transaction in the first quarter of 2002, and $13 million of minority owner's interest in the gain on the termination of the Nejapa power contract. Besides the above factors, other income also reflected lower equity earnings of $24 million from unconsolidated projects in 2002. Partially offsetting these decreases were a $15 million gain on the sale of our 50 percent interest in a petroleum product terminal in the third quarter of 2002 and an increase of $7 million in lease income related to the lease of our Corpus Christi refinery to Valero in June 2001.

Field Services

Our Field Services segment conducts our midstream activities. As part of our plan to strengthen our capital structure and enhance our liquidity, we identified several midstream assets to be sold. Once completed, these transactions should generate approximately $1 billion in cash proceeds, which will be used to reduce our outstanding debt.

During 2002, we have entered into transactions to sell midstream assets to El Paso Energy Partners, of which we have an approximate 27 percent ownership interest. In April 2002, we sold gathering and processing assets to El Paso Energy Partners, including the intrastate pipeline system we acquired in our acquisition of PG&E's midstream operations in December 2000. These assets generated EBIT of $52 million during the year ended December 31, 2001. We also announced in July 2002, the proposed sale of substantially all our natural gas gathering, processing and treating assets in the San Juan Basin to El Paso Energy Partners. This transaction is subject to customary regulatory reviews and approvals, the execution of definitive agreements and receipt of satisfactory financing. The closing of the sale is anticipated by the end of 2002. One of the San Juan Basin assets included in this transaction is our remaining interests in the Chaco cryogenic natural gas processing plant. As part of this transaction, we will be required to repurchase the Chaco processing plant from El Paso Energy Partners for $77 million in October 2021, and at that time, El Paso Energy Partners has the right to lease the plant from us for a period of ten years with the option to renew the lease annually thereafter. We expect this transaction to be completed by the end of 2002. The San Juan Basin assets generated EBIT of $102 million during the year ended December 31, 2001. The proposed sale contemplates that we will receive up to $350 million of El Paso Energy Partners' Series C units, a new class of the partnership's limited partner interests, with the balance of the consideration to be received in cash. The potential $350 million Series C issuance will be reduced by the proceeds from any common unit issuances El Paso Energy Partners may consummate before the closing of the San Juan assets sale. Assuming a price of $32 per unit, we will receive approximately 11 million of Series C units, and our current 27 percent ownership interest in El Paso Energy Partners will increase to approximately 41 percent. If the average market price is less than $27 per unit, the sale of the San Juan assets may be delayed, terminated or renegotiated.

In accordance with SFAS No. 144, the San Juan assets were classified as assets held for sale on the date we entered into the letter of intent with El Paso Energy Partners. The assets are no longer depreciated once they are classified as assets held for sale.

With the completion of these asset sales, we will have sold a substantial portion of our midstream business to El Paso Energy Partners. As a result, we expect our future EBIT to decrease considerably due to a decline in our gathering and treating activities. However, we expect the increase in earnings from our interest in El Paso Energy Partners to partially offset the anticipated decrease in EBIT.

After we complete the expected sale of the San Juan assets, the remaining assets in our Field Services segment will consist primarily of processing facilities in the Rockies, south Texas and south Louisiana regions, as well as our interest in El Paso Energy Partners. A majority of our processing contracts are percentage-of-proceeds and make-whole contracts. Accordingly, under these types of contracts we may have more sensitivity to price changes during periods when natural gas and natural gas liquids prices are volatile.

In October 2002, we announced the sale of our 14.4 percent equity interest in the Aux Sable natural gas liquids plant for approximately $10 million. We anticipate a loss on this sale of approximately $47 million and recorded a corresponding writedown of our investment in September 2002. In November 2002, we entered into an agreement to sell our Natural Buttes and Ouray natural gas gathering systems to Westport Resources Corporation for approximately $43 million. We expect to complete the transaction and record a gain on this sale of approximately $29 million in the fourth quarter for 2002. These assets generated EBIT of approximately $8 million during the year ended December 31, 2001.

We also serve as the general partner of El Paso Energy Partners. As the general partner we manage the partnership's day-to-day operations and strategic direction. 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 common and preferred units. 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 nine months ended September 30, 2002, we were reimbursed approximately $39 million for expenses incurred on behalf of the partnership. During the nine months ended September 30, 2002, our earnings and cash from El Paso Energy Partners were as follows:

	Earnings Recognized	Cash Received
	(In millions)	
General partner's share of distributions	$31	$31
Proportionate share of income available to common unit holders	8	22
Series B preference units	11	—[1]
	$50	$53

[1] The partnership is not obligated to pay these distributions until these shares are redeemed.

We do not have any loans to or from El Paso Energy Partners. In addition, except for a nominal guarantee of lease obligations on behalf of a subsidiary of El Paso Energy Partners, we have not provided any guarantees, either monetary or performance, on behalf of or for the benefit of El Paso Energy Partners nor do we have any other liabilities other than normal course of business as a result of, or arising out of, our role as the general partner or our ownership interest in El Paso Energy Partners.

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

	Quarter Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
	(In millions, except volumes and prices)			
Gathering, transportation and processing gross margins	$ 80	$ 145	$ 289	$ 440
Operating expenses	(59)	(115)	(204)	(350)
Other income (expense)	(32)	13	9	44
EBIT	$ (11)	$ 43	$ 94	$ 134
Volumes and prices				
Gathering and treating				
Volumes (BBtu/d)	2,209	6,177	3,422	6,093
Prices ($/MMBtu)	$ 0.19	$ 0.14	$ 0.17	$ 0.14
Processing				
Volumes (inlet BBtu/d)	3,883	4,551	3,984	4,263
Prices ($/MMBtu)	$ 0.11	$ 0.15	$ 0.11	$ 0.16

Third Quarter 2002 Compared to Third Quarter 2001

Total gross margins for the quarter ended September 30, 2002, were $65 million lower than the same period in 2001. The sale of our midstream assets to El Paso Energy Partners in April 2002 resulted in a reduction in margins of $43 million. Lower NGL prices in 2002 unfavorably impacted our processing volumes and margins primarily in the south Louisiana and south Texas regions by approximately $12 million. Higher processing 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 and the sale of the Dragon Trail processing plant in May 2002 resulted in additional reductions to our processing margins of $6 million and $3 million.

Operating expenses for the quarter ended September 30, 2002, were $56 million lower than the same period of 2001. The decrease was primarily due to lower operating costs of $18 million and lower depreciation expense of $9 million related to our sale of midstream assets to El Paso Energy Partners in April 2002 and October 2001. Our depreciation expense was also lower by $6 million due to the assets held for sale classification of the San Juan Basin assets in 2002 and lower amortization of goodwill due to the implementation of SFAS No. 142 in January 2002. Also contributing to the decrease was a change in our estimated environmental remediation liabilities and other charges in 2001 of $17 million.

Other income for the quarter ended September 30, 2002, was $45 million lower than the same period in 2001. In September 2002, we wrote down our investment in the Aux Sable natural gas liquids plant by approximately $47 million, in anticipation of the loss from our announced sale of this interest. This decrease was partially offset by higher earnings of $7 million in 2002 from our interests in El Paso Energy Partners.

Nine Months Ended 2002 Compared to Nine Months Ended 2001

Total gross margins for the nine months ended September 30, 2002, were $151 million lower than the same period in 2001. Margins decreased by approximately $85 million due to our sale of midstream assets to El Paso Energy Partners in April 2002. In addition, a $47 million decrease was due to lower NGL prices in 2002, which unfavorably impacted our processing margins and volumes in the south Louisiana, south Texas and Rockies regions. Higher processing 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 and the sale of the Dragon Trail processing plant in May 2002 also reduced our processing margins by $18 million and $4 million. Lower natural gas prices in the San Juan Basin in 2002 resulted in a $24 million decrease in our gathering and treating margins. Partially offsetting these decreases were favorable resolutions of fuel, rate and volume matters of $13 million in the first quarter of 2002, $8 million of unfavorable resolutions of fuel matters which occurred in 2001 and $14 million due to higher realized transportation rates and increased system efficiency from the pipeline system acquired in our acquisition of PG&E's midstream operation in December 2000. This pipeline system was one of the assets sold to El Paso Energy Partners in April 2002.

Operating expenses for the nine months ended September 30, 2002, were $146 million lower than the same period of 2001. The decrease was primarily a result of lower operating costs of $40 million and lower depreciation expense of $26 million related to our sale of midstream assets to El Paso Energy Partners in 2002 and 2001. In addition, our 2002 cost reduction plan contributed $11 million to our lower operating costs. Our depreciation expense was also lower by $4 million due to the assets held for sale classification of the San Juan Basin assets in 2002 and $6 million associated with lower amortization of goodwill due to the implementation of SFAS No. 142 in 2002. Also contributing to the decrease were $46 million of merger-related costs in 2001, which included payments to El Paso Energy Partners related to FTC ordered sales of assets owned by the partnership, and an $8 million increase in our estimated environmental remediation liabilities in 2001. For a discussion of these merger-related costs, see Item 1, Financial Statements, Note 4.

Other income for the nine months ended September 30, 2002, was $35 million lower than the same period in 2001. In September 2002, we wrote down our investment in the Aux Sable natural gas liquids plant by approximately $47 million, in anticipation of the loss from our announced sale of this interest. Also contributing to this decrease was a gain of $8 million recorded in May 2001 from the sale of our 1.01 percent non-managing interest in El Paso Energy Partners. These decreases were partially offset by higher earnings of $13 million in 2002 from our interests in El Paso Energy Partners and a $10 million gain recorded in 2002 from the sale of our Dragon Trail processing plant.

Corporate and Other

Corporate and other net expenses, which include general and administrative activities as well as the operations of our telecommunications and other miscellaneous businesses, for the quarter and nine months ended September 30, 2002, were $125 million and $1,363 million lower than the same periods in 2001. The decrease was primarily a result of $22 million and $1,176 million in merger-related charges and asset impairments for the quarter and nine months ended September 30, 2001, in connection with our merger with Coastal and additional costs of $43 million and $144 million for the quarter and nine months ended September 30, 2001 related to increased estimates of environmental remediation costs and legal obligations and reductions in the fair value of spare parts inventories to reflect changes in usability of spare parts inventories in our corporate operations based on an ongoing evaluation of our operating standards and plans following the Coastal merger. For a discussion of these costs, see Part 1, Financial Statements, Note 4. Also contributing to the decrease was $13 million and $22 million for the quarter and nine months ended September 30, 2002, in telecommunications expenses due to our organizational restructuring in November 2001. In the third quarter of 2002, we recorded a $21 million gain on the early extinguishment of debt. Partially offsetting the decrease for the nine months ended September 30, 2002, were charges of $50 million for severance payments related to our second quarter 2002 employee restructuring and costs associated with the elimination of rating and stock-price triggers in the second quarter of 2002 in our Gemstone and Chaparral investments.

Our telecommunications business consists of the following:

- Texas-based metro transport services
- Long-haul and metro dark fiber marketing activities
- Collocation and cross-connect services

Our Texas-based metro transport services business provides bandwidth transport services to wholesale customers in Austin, San Antonio, Dallas, Ft. Worth and Houston. We provide a cost-effective service because of our ability to use the telecommunications infrastructure of Southwestern Bell under our interconnection agreement with them. We are currently involved in proceedings with Southwestern Bell that could impact our cost of using their infrastructure, and possibly our ability to use this infrastructure in the future. For an additional discussion of this hearing, see Part I, Financial Statements, Note 13 under the subheading *Southwestern Bell Proceeding.* We currently have total assets in our Texas-based metro business of $387 million, which includes $163 million of goodwill. Because of the continuing decline in the telecommunications industry, we evaluate the fair value of our Texas-based assets, including our goodwill, each quarter to determine if they are impaired. As of September 30, 2002, these assets were not impaired. There are a number of factors that could impact the valuation of our Texas-based metro transport business in the future, including a negative outcome of our Southwestern Bell proceeding, a decline in our forecasted demand for services in the areas we serve or a further decline in the telecommunications industry impacting our ability to expand this business.

We also market long-haul and metro dark fiber to other telecommunications providers for use in expanding their own network infrastructure. Our inventory of dark fiber at September 30, 2002, was valued at $146 million, and includes inventory-in-progress associated with the construction of a long-haul fiber optic route from Houston, Texas to Los Angeles, California, with a cost basis of $109 million. We are currently involved in arbitration proceedings with Broadwing Communication Services, the company we contracted with to construct this route, over the construction and maintenance of this fiber optic route. For a further discussion of this matter, see Part I, Financial Statements, Note 13, under the subheading *Other Matters.* The outcome of this arbitration proceeding ranges from, if we are successful in our claims, a full recovery of amounts paid to Broadwing, which is $62 million, together with clean title to this route, to a substantial write-down or complete write-off of this route should we be unsuccessful in our claim against Broadwing or should they become financially insolvent. Consequently, we are currently unable to predict what a probable outcome will be. We will continue to carry our investment in this fiber optic route at its historical cost until we are able to determine it is probable that a permanent decline in our investment has occurred, at which time any necessary adjustment will be made. Our remaining fiber optic inventory is accounted for at the lower of its cost or market value. During the third quarter of 2002, we completed an analysis of market prices, and as a result, we wrote down our long haul fiber inventory by $8 million for routes outside of Texas.

Our collocation and cross-connect services are available through our Lakeside Technology Center, a Chicago-based telecommunications facility that provides space for telecommunications carriers designed for their unique equipment needs, as well as access to multiple network connections of various telecommunications carriers. We operate this facility under an operating lease that has a residual value guarantee of $237 million. In the second quarter of 2002, we reached a final settlement of a lease agreement at the facility with Global Crossing, who recently filed for bankruptcy. Although we received some consideration, the settlement resulted in the termination of the lease and the loss of a significant tenant at the facility. As a result of this event, we analyzed the fair value of the building. Our analysis was completed in the third quarter, and we estimated that the fair value of the building was $162 million, which is significantly below the expected residual value originally anticipated and guaranteed under our lease agreement and results in a contingent loss of $113 million. Consequently, we are amortizing this deficiency over the remaining lease term. This resulted in an additional charge of $4 million in the third quarter of 2002, and will result in a charge of $8 million for each remaining quarter through May 2006. The building design, which is beneficial for the heavy equipment, low staffing needs of a telecommunications provider, also limits the alternative uses for the facility putting pressure on the fair value of the building during this significant downturn in the telecommunications industry.

Interest and Debt Expense

Interest and debt expense for the quarter ended September 30, 2002, was $342 million, or $62 million higher than the same period in 2001. The increase was primarily due to approximately $60 million increase in interest expense from higher long-term borrowings for ongoing capital projects, investment programs and operating requirements. Also contributing to the increase was a $30 million increase in interest expense due to the Mohawk River Funding IV debt borrowed in June 2002 and the UCF debt borrowed in July 2002, as well as lower capitalized interest. These increases were partially offset by $13 million decrease in interest expense due to repayments of short-term credit facilities and lower interest rates on short-term borrowings, as well as $10 million decrease in interest expense due to repayments of other financing obligations.

Interest and debt expense for the nine months ended September 30, 2002, was $1,008 million, or $142 million higher than the same period in 2001. The increase was primarily due to $192 million increase in interest expense from higher long-term borrowings for ongoing capital projects, investment programs and operating requirements. This increase was offset by a $35 million decrease in interest expense due to retirement of long-term debt. Also contributing to the increase was a $53 million increase in interest expense due to the new UCF debt, the Mohawk River Funding IV debt and lower capitalized interest. These increases were partially offset by a $42 million decrease in interest expense due to repayments of short-term credit facilities and lower interest rates on short-term borrowings, and a $26 million decrease in interest expense due to lower receivable factoring and lower interest rates on other debts. We anticipate interest and debt expenses will continue to exceed last year's levels throughout the remainder of 2002.

Returns on Preferred Interests of Consolidated Subsidiaries

Returns on preferred interests of consolidated subsidiaries for the quarter and nine months ended September 30, 2002, were $13 million and $48 million lower than the same periods in 2001, primarily due to lower interest rates in 2002. Most of these returns are based on variable short-term rates, which were lower on average in 2002 versus the same periods in 2001. Partially offsetting these decreases were higher returns on preferred interests issued as part of our Gemstone investment completed in November 2001.

Income Taxes

Income tax benefit for the quarter ended September 30, 2002, was $14 million resulting in an effective tax rate of 30 percent. Income tax expense for the nine months ended September 30, 2002, was $105 million resulting in an effective tax rate of 32 percent. Our effective tax rates were different than the statutory rate of 35 percent primarily due to the following:

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

Income tax expense for the quarter and nine months ended September 30, 2001, was $102 million and $4 million, resulting in effective tax rates of 32 percent and 1 percent. The nine months ended September 30, 2001 expense includes $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 for the nine months ended September 30, 2001 was 35 percent. Other differences between the effective tax rates and the statutory tax 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.

Commitments and Contingencies

See Item 1, Financial Statements, Note 13, which is incorporated herein by reference.

New Accounting Pronouncements Not Yet Adopted

See Item 1, Financial Statements, Note 18, 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 2001 Annual Report on Form 10-K, and as set forth below:

A downgrade of our credit ratings to below investment grade could significantly impact our liquidity.

Moody's and Standard and Poor's currently rate our senior unsecured debt at their lowest "investment grade" ratings and continue to keep us on negative credit watch. If either or both of these credit rating agencies, or any other rating agency, lower our rating to "below investment grade", our liquidity would be immediately and significantly impacted. Additional cash would be required by our counterparties to support our energy trading activities. Additionally, many of our financial guarantees, purchase obligations and other commercial commitments could be negatively impacted by lower credit ratings. Any such downgrades could also affect our ability to obtain additional financing in the future and would affect the terms of any such financing.

An adverse ruling or outcome in our regulatory and legal matters in and relating to California could have a material impact on us.

We and some of our subsidiaries are parties to lawsuits in California related to alleged unfair and unlawful business practices, complaints before the FERC related to the alleged exercise of market power violations of marketing affiliate regulations, and an alleged lack of compliances with FERC regulations in the transportation of gas to California. If a court or regulatory agency rule against us or one of our subsidiaries in one of these actions, the impact of such a ruling or any penalties, awards or judgments resulting from such a ruling could have a significant impact on us. For example, when the ALJ issued its initial decision in

September 2002 that our pipeline withheld capacity from California, our stock price was immediately and negatively affected and the credit spreads in our debt widened. If the ALJ's decision is upheld by the FERC or if any other lawsuits or regulatory actions in California are decided against us, it could have a significant and sustained impact on our liquidity, credit rating and our ability to raise capital to meet our ongoing and future investing and financing needs.

Our objectives in exiting the energy trading business may not be achieved in the time period or in the manner we expect, if at all.

We recently announced our intention to exit the energy trading business and pursue an orderly liquidation of our trading portfolio. If we are unable to achieve these objectives in the time period or the manner that we expect, it could have a substantial negative impact on our cash flows, liquidity and financial position. The ability to achieve our goals in the liquidation is subject to factors beyond our control, including, among others, obtaining maximum cash flow from our trading portfolio and isolating the credit and liquidity needs of the energy trading business from the rest of our business.

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 2001 Annual Report on Form 10-K, 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 energy related contracts and is prepared based on a confidence level of 95 percent and a one-day holding period.

	September 30, 2002	December 31, 2001
	(In millions)	
Trading Value-at-Risk	$23	$18
Non-Trading Value-at-Risk	$ 7	$15
Portfolio Value-at-Risk	$18	$17

Portfolio Value-at-Risk represents the combined Value-at-Risk for our trading and non-trading price risk management activities. The separate calculation of Value-at-Risk for trading and non-trading contracts ignores the natural correlation that exists between 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.

The $5 million increase in our trading Value-at-Risk is attributable to our Snøhvit transaction, which is a long-term LNG purchase contract. The increase in trading Value-at-Risk is offset by our efforts to downsize our trading activities and limit our investment in our trading operations.

Our non-trading Value-at-Risk decreased by $8 million due to a reduction of our hedged volumes of future natural gas production during 2002. We reduced these hedged volumes to reduce the cash requirements of our non-trading price risk management activities.

Item 4. Controls and Procedures

Under the supervision and with the participation of our 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 within 90 days of the filing date of this quarterly report pursuant to Rules 13a-15 and 15d-15 under the Securities Exchange Act of 1934 (the "Exchange Act"). Based on that evaluation, our principal executive officer and principal financial officer have concluded that these controls and procedures are effective. There were no significant changes in our internal controls or in other factors that could significantly affect these controls subsequent to the date of their evaluation.

Disclosure controls and procedures 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 and procedures 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.

The principal executive officer and principal financial officer certifications required under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 have been included herein, or as Exhibits to this Quarterly Report on Form 10-Q, as appropriate.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Financial Statements, Note 13, 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 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 of the State of California, San Francisco County, and *Tom McClintock, et al v. Vikram Budhrajaetal,* filed May 1, 2002, in the Superior Court of the State of California, Los Angeles County.

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 minimize the chances 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.

The purported shareholder class actions filed in the U.S. District Court for the Southern District of Texas, Houston Division, are: *Marvin Goldfarb, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine*, filed July 18, 2002; *Residuary Estate Mollie Nussbacher, Adele Brody Life Tenant, et al v. El Paso Corporation, William Wise, and H. Brent Austin*, filed July 25, 2002; *George S. Johnson, et al v. El Paso Corporation, William Wise, and H. Brent Austin*, filed July 29, 2002; *Renneck Wilson, et al v. El Paso Corporation, William Wise, H. Brent Austin, and Rodney D. Erskine*, filed August 1, 2002; and *Sandra Jean Malin Revokable 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; *Stephanie 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, Rodney D. Erskine and H. Brent Austin*, filed October 4, 2002. *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 action filed in Houston is: *Grunet Realty Corp. v. William A. Wise, Byron Allumbaugh, John Bissell, Juan Carlos Braniff, James Gibbons, Anthony Hall Jr., Ronald Kuehn Jr., J. Carleton MacNeil Jr., Thomas McDade, Malcolm Wallop, Joe Wyatt and Dwight Scott*, filed August 22, 2002.

The shareholder derivative action filed in Delaware is: *Stephen Brudno 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 and Joe Wyatt*, filed October 2, 2002.

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. Sellers of Long-Term Contracts to the California Department of Water; 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.*

Item 2. Changes in Securities and Use of Proceeds

None

Item 3. Defaults Upon Senior Securities

None.

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

None.

Item 5. Other Information

None.

Item 6. Exhibits and Reports on Form 8-K

a. Exhibits

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

Exhibit Number	Description
*3.B	Amended and Restated By-laws of El Paso dated November 7, 2002.
4.D	Indenture dated as of May 10, 1999, by and between El Paso and JPMorgan Chase Bank (formerly The Chase Manhattan Bank), as Trustee (Exhibit 4.1 to our Form 8-K dated May 10, 1999); Seventh Supplemental Indenture dated as of June 10, 2002, by and between El Paso and JPMorgan Chase Bank (formerly known as The Chase Manhattan Bank), as Trustee (Exhibit 4.2 to our Registration Statement on Form S-4 filed July 17, 2002), Eighth Supplemental Indenture dated as of June 26, 2002, between El Paso and JPMorgan Chase Bank (formerly known as The Chase Manhattan Bank), as Trustee (Exhibit 4.A to our Form 8-K filed June 26, 2002).
4.F	Registration Rights Agreement dated as of June 10, 2002, between El Paso and Credit Suisse First Boston Corporation (Exhibit 4.3 to our Registration Statement on Form S-4 filed July 17, 2002).
*10.BB	Amended and Restated Participation Agreement, dated as of April 12, 2002 by and among El Paso, Limestone Electron Trust, Limestone Electron, Inc, Credit Suisse First Boston (USA), Inc., El Paso Chaparral Holding Company, El Paso Chaparral Holding II Company, El Paso Chaparral Investor, L.L.C., El Paso Chaparral Management, L.P., Chaparral Investors, L.L.C., A Mesquite Investors, L.L.C., El Paso Electron Overfund Trust, El Paso Electron Share Trust, Electron Trust, Wilmington Trust Company and The Bank of New York.
*10.BB.1	Fifth Amended and Restated Limited Liability Company Agreement of Chaparral Investors, L.L.C., dated as of April 12, 2002.
*10.BB.2	Third Amended and Restated Limited Liability Company Agreement of Mesquite Investors, L.L.C., dated as of March 27, 2000.
*10.BB.3	Amended and Restated Management Agreement dated as of March 27, 2000 among El Paso Chaparral Management, L.P., Chaparral Investors, L.L.C., Mesquite Investors, L.L.C., and El Paso Chaparral Investor, L.L.C.
*10.BB.4	Third Amended and Restated Trust Agreement of Limestone Electron Trust, dated as of April 12, 2002, by Wilmington Trust Company, El Paso, Electron Trust and Limestone Electron Trust.

Exhibit Number	Description
*10.BB.5	Indenture, dated as of April 26, 2002, among Limestone Electron Trust, Limestone Electron, Inc., The Bank of New York, and El Paso.
*10.CC	Amended and Restated Participation Agreement, dated as of April 24, 2002, by and among El Paso, EPED Holding Company, EPED B Company, Jewel Investor, L.L.C., Gemstone Investor Limited, Gemstone Investor, Inc., Topaz Power Ventures, L.L.C., Emerald Finance, L.L.C., Citrine FC Company, Garnet Power Holdings, L.L.C., Diamond Power Ventures, L.L.C., Diamond Power Holdings, L.L.C., Amethyst Power Holdings, L.L.C., Aquamarine Power Holdings, L.L.C., Peridot Finance S.à r.l., Gemstone Administração Ltda., El Paso Gemstone Share Trust, Wilmington Trust Company, and The Bank of New York.
*10.CC.1	Shareholders' Agreement dated as of April 24, 2002, by and among Gemstone Investor Limited, Jewel Investor, L.L.C., El Paso, and The Bank of New York.
*10.CC.2	Second Amended and Restated Limited Liability Company Agreement of Diamond Power Ventures, L.L.C. dated as of April 24, 2002.
*10.CC.3	Second Amended and Restated Limited Liability Company Agreement of Topaz Power Ventures, L.L.C. dated as of April 24, 2002.
*10.CC.4	Second Amended and Restated Limited Liability Company Agreement of Garnet Power Holdings, L.L.C., dated as of April 24, 2002.
*10.CC.5	Management Agreement, dated as of November 1, 2001, by and among Gemstone Administração Ltda., Garnet Power Holdings, L.L.C., Diamond Power Ventures, L.L.C., Diamond Power Holdings, L.L.C., and EPED B Company.
*10.CC.6	Indenture, dated as of May 9, 2002, among Gemstone Investor Limited, Gemstone Investor, Inc., The Bank of New York, and El Paso.
*10.DD	Fourth Amended and Restated Partnership Agreement of Clydesdale Associates, L.P., dated as of July 19, 2002.
*10.DD.1	Amended and Restated Sponsor Subsidiary Credit Agreement dated as of July 19, 2002, among Noric Holdings, L.L.C., each Other Sponsor Subsidiary, Clydesdale Associates, L.P., and Wilmington Trust Company.
*10.DD.2	Amended and Restated El Paso Agreement, dated as of July 19, 2002, made by El Paso.
*10.EE	Third Amended and Restated Company Agreement of Trinity River Associates, L.L.C. dated as of March 29, 2002.
*10.EE.1	Second Amended and Restated Sponsor Subsidiary Credit Agreement dated as of March 29, 2002, Sabine River Investors, L.L.C., each Other Sponsor Subsidiary, Trinity River Associates, L.L.C., and Wilmington Trust Company.
*10.EE.2	Second Amended and Restated El Paso Agreement, dated as of March 29, 2002, made by El Paso.
*10.FF	Second Amended and Restated Agreement of Limited Partnership of El Paso Energy Partners, L.P. effective as of August 31, 2000.
*99.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.
*99.B	Certification of Chief Financial Officer pursuant to 18 U.S.C. § 1350 as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002.

Undertaking

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

b. Reports on Form 8-K

Date	Event Reported
July 12, 2002	Announced the receipt of a subpoena for documents.
July 22, 2002	Announced the removal of the rating trigger on the Clydesdale agreements.
September 24, 2002	Responded to a FERC administrative law judge's proposed decision on our natural gas pipeline.
September 25, 2002	Communicated our opinion of the proposed decision issued by a FERC administrative law judge.
September 30, 2002	Announced management changes.
October 9, 2002	Updated information for our sale of the San Juan midstream assets to El Paso Energy Partners.
October 9, 2002	Updated 5-year historical selected financial data for discontinued operations and the adoption of new accounting standards.
October 9, 2002	Filed our Computation of Ratio of Earnings to Fixed charges for five years ended December 31, 2001, and for the six months ended June 30, 2002 and 2001.
October 31, 2002	Announced the assignment of Snøhvit Supply Contract and Cove Point LNG Capacity to Statoil ASA.

We also furnished to the SEC under Item 9, Regulation FD, Current Reports on Form 8-K. Item 9 Current Reports on Form 8-K are not considered to be "filed for purposes of Section 18 of the Securities and Exchange Act of 1934 and are not subject to the liabilities of that section, but are filed to provide full disclosure under Regulation FD." Current Reports on Form 8-K dated July 10, July 12, July 23, July 25, August 8, August 14, September 30, two on October 2, and October 9, 2002, were provided for informational purposes within this Quarterly Report on Form 10-Q.

SIGNATURES

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

EL PASO CORPORATION

Date: November 14, 2002

/s/ D. Dwight Scott

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

Date: November 14, 2002

/s/ Jeffrey I. Beason

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

CERTIFICATION

I, William A. Wise, certify that:

1. I have reviewed this quarterly report on Form 10-Q of El Paso Corporation;

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

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

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

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

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

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

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

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

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

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

/s/ William A. Wise

William A. Wise
Chairman of the Board and
Chief Executive Officer
(Principal Executive Officer)
El Paso Corporation

Date: November 14, 2002

CERTIFICATION

I, D. Dwight Scott, certify that:

1. I have reviewed this quarterly report on Form 10-Q of El Paso Corporation;

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

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

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

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

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

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

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

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

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

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

/s/ D. Dwight Scott

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

Date: November 14, 2002