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

Form 10-Q

(Mark One)

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

For the quarterly period ended June 30, 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 August 9, 2002: 584,848,649

PART I — FINANCIAL INFORMATION

Item 1. Financial Statements

EL PASO CORPORATION

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

	Quarter Ended June 30,		Six Months Ended June 30,	
	2002	2001	2002	2001
Operating revenues	$2,987	$3,757	$6,742	$7,724
Operating expenses				
Cost of products and services	1,472	1,965	3,085	3,888
Operation and maintenance	584	815	1,246	1,472
Restructuring and merger-related costs and asset impairments	63	601	405	1,760
Ceiling test charges	234	—	267	—
Depreciation, depletion and amortization	352	325	717	644
Taxes, other than income taxes	63	94	148	214
	2,768	3,800	5,868	7,978
Operating income (loss)	219	(43)	874	(254)
Other income				
Earnings from unconsolidated affiliates	129	99	191	200
Net gain on sale of assets	15	17	31	12
Other, net	48	80	28	126
	192	196	250	338
Income before interest, income taxes and other charges	411	153	1,124	84
Interest and debt expense	359	291	666	586
Minority interest	43	56	83	118
Income taxes	1	(63)	119	(98)
	403	284	868	606
Income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	8	(131)	256	(522)
Discontinued operations, net of income taxes	(67)	(3)	(86)	(2)
Extraordinary items, net of income taxes	—	41	—	31
Cumulative effect of accounting changes, net of income taxes	14	—	168	—
Net income (loss)	$ (45)	$ (93)	$ 338	$ (493)
Basic earnings per common share				
Income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	$ 0.02	$(0.26)	$ 0.48	$(1.04)
Discontinued operations, net of income taxes	(0.13)	—	(0.16)	—
Extraordinary items, net of income taxes	—	0.08	—	0.06
Cumulative effect of accounting changes, net of income taxes	0.03	—	0.32	—
Net income (loss)	$(0.08)	$(0.18)	$ 0.64	$(0.98)
Diluted earnings per common share				
Income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	$ 0.02	$(0.26)	$ 0.48	$(1.04)
Discontinued operations, net of income taxes	(0.13)	—	(0.16)	—
Extraordinary items, net of income taxes	—	0.08	—	0.06
Cumulative effect of accounting changes, net of income taxes	0.03	—	0.32	—
Net income (loss)	$(0.08)	$(0.18)	$ 0.64	$(0.98)
Basic average common shares outstanding	530	505	529	504
Diluted average common shares outstanding	532	505	531	504
Dividends declared per common share	$ 0.22	$ 0.21	$ 0.44	$ 0.43

See accompanying notes.

EL PASO CORPORATION

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

	June 30, 2002	December 31, 2001
ASSETS		
Current assets		
Cash and cash equivalents	$ 2,663	$ 1,148
Accounts and notes receivable, net		
Customer	5,252	5,038
Unconsolidated affiliates	1,260	911
Other	906	873
Inventory	890	815
Assets from price risk management activities	1,690	2,702
Other	2,028	1,142
Total current assets	14,689	12,629
Property, plant and equipment, at cost		
Pipelines	17,868	17,596
Natural gas and oil properties, at full cost	13,597	14,466
Refining, crude oil and chemical facilities	2,383	2,425
Gathering and processing systems	1,682	2,628
Power facilities	1,068	834
Other	612	565
	37,210	38,514
Less accumulated depreciation, depletion and amortization	13,792	14,224
Total property, plant and equipment, net	23,418	24,290
Other assets		
Investments in unconsolidated affiliates	4,998	5,297
Assets from price risk management activities	3,170	2,118
Intangible assets, net	1,460	1,442
Other	2,268	2,395
	11,896	11,252
Total assets	$50,003	$48,171

See accompanying notes.

EL PASO CORPORATION

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

	June 30, 2002	December 31, 2001
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 5,498	$ 4,944
Unconsolidated affiliates	27	26
Other	770	959
Short-term borrowings and other financing obligations	1,545	3,314
Notes payable to unconsolidated affiliates	355	504
Liabilities from price risk management activities	1,601	1,868
Other	1,411	1,950
Total current liabilities	11,207	13,565
Debt		
Long-term debt and other financing obligations	16,375	12,816
Notes payable to unconsolidated affiliates	200	368
	16,575	13,184
Other liabilities		
Liabilities from price risk management activities	1,523	1,231
Deferred income taxes	4,523	4,395
Other	2,003	2,427
	8,049	8,053
Commitments and contingencies		
Securities of subsidiaries		
Company-obligated preferred securities of consolidated trusts	925	925
Minority interests	3,229	3,088
	4,154	4,013
Stockholders' equity		
Common stock, par value $3 per share; authorized 1,500,000,000 shares and issued 592,257,717 shares in 2002; authorized 750,000,000 shares and issued 538,363,664 shares in 2001	1,777	1,615
Additional paid-in capital	3,973	3,130
Retained earnings	5,007	4,902
Accumulated other comprehensive income (loss)	(331)	157
Treasury stock (at cost) 7,325,631 shares in 2002 and 7,628,799 shares in 2001	(252)	(261)
Unamortized compensation	(156)	(187)
Total stockholders' equity	10,018	9,356
Total liabilities and stockholders' equity	$50,003	$48,171

See accompanying notes.

EL PASO CORPORATION

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

	Six Months Ended June 30, 2002	Six Months Ended June 30, 2001
Cash flows from operating activities		
Net income (loss)	$ 338	$ (493)
Less loss from discontinued operations, net of income taxes	(86)	(2)
Net income (loss) before discontinued operations	424	(491)
Adjustments to reconcile net income (loss) to net cash from operating activities		
Non-cash gains from trading and power activities	(527)	(347)
Non-cash portion of merger-related costs, asset impairments and changes in estimates	342	1,462
Depreciation, depletion and amortization	717	644
Ceiling test charges	267	—
Undistributed earnings of unconsolidated affiliates	(72)	(93)
Net gain on the sale of assets	(31)	(12)
Deferred income tax expense (benefit)	116	(73)
Extraordinary items	—	(53)
Cumulative effect of accounting changes	(177)	—
Other non-cash income items	134	6
Working capital changes	(713)	1,710
Non-working capital changes and other	(186)	(89)
Cash provided by continuing operations	294	2,664
Cash provided by (used in) discontinued operations	48	(9)
Net cash provided by operating activities	342	2,655
Cash flows from investing activities		
Additions to property, plant and equipment	(1,532)	(1,714)
Additions to investments	(497)	(571)
Net proceeds from the sale of assets	1,342	465
Net proceeds from investments	23	151
Cash deposited in escrow	(189)	(133)
Return of cash deposited in escrow	11	—
Repayment of notes receivable from unconsolidated affiliates	175	172
Other	48	2
Cash used in continuing operations	(619)	(1,628)
Cash used in discontinued operations	(7)	(26)
Net cash used in investing activities	(626)	(1,654)
Cash flows from financing activities		
Net repayments under commercial paper and short-term credit facilities	(558)	(945)
Borrowings under credit facilities	—	245
Repayments on credit facilities	—	(700)
Repayments of notes payable	(11)	—
Payments to retire long-term debt and other financing obligations	(1,549)	(1,057)
Net proceeds from the issuance of long-term debt and other financing obligations	3,504	2,279
Payments to minority interests	(54)	—
Issuances of common stock	1,022	37
Dividends paid	(224)	(167)
Increase in notes payable to unconsolidated affiliates	3	4
Decrease in notes payable to unconsolidated affiliates	(324)	(385)
Contributions from (distributions to) discontinued operations	31	(26)
Cash provided by (used in) continuing operations	1,840	(715)
Cash provided by (used in) discontinued operations	(31)	26
Net cash provided by (used in) financing activities	1,809	(689)
Increase in cash and cash equivalents	1,525	312
Less increase (decrease) in cash and cash equivalents related to discontinued operations	10	(9)
Increase in cash and cash equivalents from continuing operations	1,515	321
Cash and cash equivalents		
Beginning of period	1,148	745
End of period	$ 2,663	$ 1,066

See accompanying notes.

EL PASO CORPORATION

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

	Quarter Ended June 30, 2002	Quarter Ended June 30, 2001	Six Months Ended June 30, 2002	Six Months Ended June 30, 2001
Net income (loss)	$ (45)	$ (93)	$ 338	$ (493)
Foreign currency translation adjustments	28	—	27	(14)
Unrealized net gains (losses) from cash flow hedging activity				
Cumulative-effect transition adjustment (net of tax of $673)	—	—	—	(1,280)
Unrealized mark-to-market losses arising during period (net of tax of $79 and $214 in 2002, and $450 and $327 in 2001)	(114)	891	(346)	652
Reclassification adjustments for changes in initial value to settlement date (net of tax of $29 and $83 in 2002, and $135 and $384 in 2001)	(74)	219	(169)	682
Other	—	(4)	—	(4)
Other comprehensive income (loss)	(160)	1,106	(488)	36
Comprehensive income (loss)	$(205)	$1,013	$(150)	$ (457)

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 (SEC). 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 June 30, 2002, and for the quarters and six months ended June 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 3, 4, 5, 6 and 7 below), 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 discussed below:

Goodwill and Other Intangible Assets

Our intangible assets consist primarily of goodwill resulting from acquisitions. On January 1, 2002, we adopted Statement of Financial Accounting Standards (SFAS) No. 141, *Business Combinations*, and SFAS No. 142, *Goodwill and Other Intangible Assets*. These standards require that we recognize goodwill separately from other intangible assets. In addition, goodwill and indefinite-lived intangibles are no longer amortized. Instead, 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, and recognized a pretax and after-tax gain of $154 million related to the write-off 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 during the first quarter of 2002, and concluded that we did not have any adjustment to our goodwill. Amortization of goodwill and negative goodwill would have been approximately $7 million and $14 million, net of income taxes, for the quarter and six months ended June 30, 2002 had we not adopted these standards. In addition, had we applied the amortization provisions of SFAS No. 141 and 142 on January 1, 2001, we would have reported the following amounts:

	Quarter Ended June 30, 2001	Six Months Ended June 30, 2001
	(In millions, except per common share amounts)	
Loss from continuing operations before extraordinary items and cumulative effect of accounting changes	$ (124)	$ (508)
Loss per common share	$(0.25)	$(1.01)
Net loss	$ (86)	$ (479)
Net loss per common share	$(0.17)	$(0.95)

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 operating losses in these operations. We applied SFAS No. 144 in accounting for our coal mining operations, which met all of the requirements to be treated as discontinued operations in the second quarter of 2002. See Note 6 for further information.

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 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 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.

In June 2002, the Emerging Issues Task Force (EITF) reached a consensus in EITF Issue No. 02-3, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities,* requiring that all mark-to-market gains and losses related to energy trading contracts, including physical settlements, be recorded in the income statement on a net basis instead of being reported on a gross basis as revenues for physically settled sales and expenses for physically settled purchases. We elected to adopt this consensus issue in the second quarter, and now report our trading activity on a net basis as a component of revenues. We have also applied this guidance to all prior periods, which had no impact on previously reported net income or stockholders' equity. Revenues and costs that have been netted as a result of adopting this consensus were as follows:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2002	2001	2002	2001
	(In millions)			
Gross operating revenues	$ 15,889	$13,671	$ 29,011	$ 31,359
Costs reclassified	(12,902)	(9,914)	(22,269)	(23,635)
Net operating revenues reported in the income statement	$ 2,987	$ 3,757	$ 6,742	$ 7,724

The EITF continues to evaluate disclosure and valuation issues in its ongoing deliberations on Issue No. 02-3, and we will monitor and assess the impact of adopting these issues when and if a consensus is reached.

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 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 changes because the restructured contract must be marked to its fair value under SFAS No. 133. In the period the restructuring is completed, the book value of the restructured contract 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 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 costs 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, as in our Mount Carmel transaction. We also employed the principles of our power restructuring business in reaching a settlement of the dispute under our Nejapa power contract which included a cash payment to us. We record these payments as revenues. During the first six months of 2002, we recognized revenues from power restructuring and contract termination activities of $1,103 million and corresponding costs of $539 million, most of which occurred during the first quarter.

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.

In March 2002, we sold natural gas and oil properties located in east and south Texas. Net proceeds from this sale were approximately $512 million. We did not recognize a gain or loss on the properties sold since they were not significant in terms of the total costs or reserves in our full cost pool of properties.

In April 2002, we sold midstream assets for approximately $735 million to El Paso Energy Partners, L.P., a publicly traded master limited partnership of which our subsidiary serves as the general partner. Net proceeds from this sale were approximately $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. No gain or loss was recognized on this sale.

In May and June 2002, we completed sales of natural gas and oil properties, a natural gas gathering system and a natural gas plant. Net proceeds from these sales were approximately $325 million. We recognized a gain of $10 million, $6 million after taxes, on the natural gas gathering system and the plant. This gain was recorded on our income statement in net gain on sale of assets.

We have also announced the sales of additional assets to El Paso Energy Partners, L.P., including $782 million of onshore and offshore natural gas and oil gathering systems, natural gas liquids transportation and fractionation assets, and $133 million of natural gas and oil production properties and related contracts and natural gas gathering systems. The sale of the natural gas and oil production properties was completed in July 2002, and no gain or loss was recognized. The remaining asset sales are expected to occur by the end of the fourth quarter of 2002.

3. Restructuring and Merger-Related Costs and Asset Impairments

Our organizational restructuring and merger-related costs and asset impairments for the periods ended June 30 consisted of the following:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2002	2001	2002	2001
	(In millions)			
Restructuring costs	$63	$ —	$ 63	$ —
Merger-related costs	—	494	—	1,653
Asset impairments	—	107	342	107
Total	$63	$601	$405	$1,760

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 May 2002, we completed an employee restructuring across all of our operating segments which resulted in a reduction of approximately 353 full-time positions through terminations. In connection with this, we incurred $23 million of employee severance and termination costs. As of June 30, 2002, we had paid $8 million of this charge, and the remainder will be paid in the third quarter of 2002. Employee severance costs included severance payments and costs for pension benefits settled and curtailed under existing benefit plans. We also incurred fees of $40 million to eliminate stock price and credit rating triggers related to our Gemstone and Chaparral investments. See Note 15 for further information on the Chaparral and Gemstone amendments.

Merger-Related Costs

On January 29, 2001, we merged with The Coastal Corporation in a merger that was accounted for as a pooling of interests. The following are costs we incurred related to the merger:

	Quarter Ended June 30, 2001	Six Months Ended June 30, 2001
	(In millions)	
Employee severance, retention and transition costs	$ 19	$ 819
Transaction costs	13	67
Business and operational integration costs	399	416
Merger-related asset impairments	18	152
Other	45	199
	$494	$1,653

Employee severance, retention and transition costs include direct payments to, and benefit costs for, terminated employees and early retirees that occurred as a result of our merger-related workforce reduction and consolidation. Following the Coastal merger, we completed an employee restructuring across all of our operating segments, reducing 3,285 full-time positions through a combination of early retirements and terminations. Employee severance costs include severance payments and costs for pension and post-retirement benefits settled and curtailed under existing benefit plans as a result of this restructuring. Retention charges include payments to employees who were retained following the merger and payments to employees to satisfy contractual obligations. Transition costs relate to costs to relocate employees and costs for terminated and retired employees arising after their severance date to transition their job responsibilities to the ongoing workforce. The amount of employee severance, retention and transition costs paid and charged against the accrued amount for the six months ended June 30, 2001, was approximately $342 million. The pension and post retirement benefits were accrued at the merger date and will be paid over the applicable benefit periods of the terminated and retired employees. The rest of the charges were paid during the remainder of 2001.

Also included in employee severance, retention and transition costs for the six months ended June 30, 2001, was a charge of $278 million resulting from the issuance of approximately 4 million shares of common stock incurred on the date of the Coastal merger in exchange for the fair value of Coastal employees' and directors' stock options.

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

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

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

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

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.

During the second quarter of 2001, we recorded other asset impairment charges of $107 million. These charges consisted of a $60 million write-down primarily of our investment in a telecommunications company in Brazil, and charges of $47 million primarily related to Merchant Energy's impairment of its East Asia Power investment in the Philippines. These write-downs were a result of weak economic conditions causing a permanent decline in the value of these investments. We continue to hold these investments.

4. Changes in Accounting Estimates

Included in our operation and maintenance costs for the quarter and six months ended June 30, 2001, were approximately $203 million in costs related to changes in estimates. They consist of $159 million of additional environmental remediation liabilities and a $44 million charge to reduce the value of our spare parts inventories to reflect changes in the usability of these parts in our worldwide operations. Both charges arose as a result of an ongoing evaluation of our operating standards and plans following our merger with Coastal and our combined operating strategy. These changes in estimates reduced our after-tax earnings by approximately $138 million.

5. Ceiling Test Charges

Under the full cost method of accounting for natural gas and oil properties, we perform quarterly ceiling tests to evaluate whether the carrying value of natural gas and oil properties exceeds the present value of future net revenues, discounted at 10 percent, plus the lower of cost or fair market value of unproved properties. As of June 30, 2002, we recorded ceiling test charges of $267 million, of which $33 million was charged during the first quarter and $234 million during the second quarter. The 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 the end of the second quarter, which was approximately $1.43 per million British thermal units.

We use financial instruments to hedge against volatility of natural gas and oil prices. The impact of these hedges was considered in determining our 2002 ceiling test charge, and will be factored into future ceiling test calculations. Had the impact of our hedges not been included in calculating our 2002 ceiling test charge, the charge would not have materially changed since we do not significantly hedge our international production activities.

6. 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 the operations of our Merchant Energy segment, consist of fifteen active underground and two surface mines located in Kentucky, Virginia and West Virginia. We expect to complete the sale of these operations before the end of 2002. Following the authorization of the sale by our Board of Directors, we compared the carrying value of the underlying assets to our estimated sales proceeds, net of estimated selling costs, based on bids received in the sales process. Because this carrying value was higher than our estimated net sales proceeds, we recorded a charge of $148 million, which has been included in our total loss from discontinued operations in the second quarter of 2002.

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 June 30, 2002, as 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 June 30,		Six Months Ended June 30,	
	2002	2001	2002	2001
	(In millions)			
Operating Results:				
Revenues	$ 101	$ 69	$ 168	$ 142
Costs and expenses	(216)	(72)	(312)	(146)
Other income	6	—	6	2
Loss before income taxes	(109)	(3)	(138)	(2)
Income tax benefit	42	—	52	—
Loss from discontinued operations, net of income taxes	$ (67)	$ (3)	$ (86)	$ (2)

	June 30, 2002	December 31, 2001
	(In millions)	
Financial Position Data:		
Assets		
Current assets	$ 70	$ 61
Property, plant and equipment, net	139	301
Non-current assets	26	26
Total assets	$235	$388
Liabilities		
Current liabilities	$ 29	$ 35
Non-current liabilities	64	94
Total liabilities	$ 93	$129

7. Extraordinary Items

Under an FTC 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 quarter and six months ended June 30, 2001, net proceeds from these sales were approximately $135 million and $279 million, and we recognized extraordinary net gains of approximately $41 million and $31 million, net of income taxes of approximately $23 million and $22 million.

8. Earnings Per Share

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

	Quarter Ended June 30, 2002 Basic	2002 Diluted	2001 Basic
	(In millions, except per common share amounts)		
Income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	$ 8	$ 8	$ (131)
Discontinued operations, net of income taxes	(67)	(67)	(3)
Extraordinary items, net of income taxes	—	—	41
Cumulative effect of accounting changes, net of income taxes	14	14	—
Adjusted net loss	$ (45)	$ (45)	$ (93)
Average common shares outstanding	530	530	505
Effect of dilutive securities			
Stock options	—	1	—
Restricted stock	—	—	—
FELINE PRIDES[SM]	—	1	—
Average common shares outstanding[(1)]	530	532	505
Earnings (loss) per common share			
Income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	$ 0.02	$ 0.02	$(0.26)
Discontinued operations, net of income taxes	(0.13)	(0.13)	—
Extraordinary items, net of income taxes	—	—	0.08
Cumulative effect of accounting changes, net of income taxes	0.03	0.03	—
Adjusted net loss	$(0.08)	$(0.08)	$(0.18)

(1) Due to their antidilutive effect on earnings (loss) per common share, for 2002, we excluded a total of 16 million shares for the assumed conversion of trust preferred securities and convertible debentures, and for 2001, we excluded a total of 27 million shares for the assumed conversion of stock options, restricted stock, FELINE PRIDES[SM], trust preferred securities and convertible debentures.

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

	Six Months Ended June 30,		
	2002		2001
	Basic	Diluted	Basic
	(In millions, except per common share amounts)		
Income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	$ 256	$ 256	$ (522)
Discontinued operations, net of income taxes	(86)	(86)	(2)
Extraordinary items, net of income taxes	—	—	31
Cumulative effect of accounting changes, net of income taxes	168	168	—
Adjusted net income (loss)	$ 338	$ 338	$ (493)
Average common shares outstanding	529	529	504
Effect of dilutive securities			
Stock options	—	1	—
Restricted stock	—	—	—
FELINE PRIDES℠	—	1	—
Average common shares outstanding[(1)]	529	531	504
Earnings (loss) per common share			
Income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	$ 0.48	$ 0.48	$(1.04)
Discontinued operations, net of income taxes	(0.16)	(0.16)	—
Extraordinary items, net of income taxes	—	—	0.06
Cumulative effect of accounting changes, net of income taxes	0.32	0.32	—
Adjusted net income (loss)	$ 0.64	$ 0.64	$(0.98)

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

9. 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 June 30, 2002 and December 31, 2001:

	June 30, 2002	December 31, 2001
	(In millions)	
Net assets (liabilities)		
Energy contracts		
Trading contracts[(1)(3)]	$1,078	$1,295
Non-trading contracts[(2)(3)]		
Derivatives designated as hedges	(323)	459
Other derivatives	966	—
Total energy contracts	1,721	1,754
Interest rate and foreign currency contracts	15	(33)
Total price risk management activities	$1,736	$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.*

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

(3) We do no 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.

Included in other derivatives as of June 30, 2002, are $979 million of derivative contracts related to the power restructuring activities of our consolidated subsidiaries. Of this amount, $882 million relates to a power restructuring that occurred during the first quarter of 2002 at our Eagle Point Cogeneration power plant, and $97 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 $13 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 in east and south Texas that were sold in the first quarter of 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 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 is updated 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. We removed the hedging designation on derivatives with a fair value loss of $61 million in May 2002. This amount, net of income taxes of $23 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 $38 million in accumulated other comprehensive income, we estimate that unrealized gains of $7 million, net of income taxes, related to these derivatives will be reclassified to income over the next twelve months.

10. Inventory

Our inventory consisted of the following:

	June 30, 2002	December 31, 2001
	(In millions)	
Refined products, crude oil and chemicals	$636	$577
Materials and supplies and other	198	197
Natural gas in storage	56	41
	$890	$815

11. Debt and Other Credit Facilities

At June 30, 2002, our weighted average interest rate on our commercial paper and short-term credit facilities was 2.7%, and at December 31, 2001, it was 3.2%. We had the following short-term borrowings and other financing obligations:

	June 30, 2002	December 31, 2001
	(In millions)	
Commercial paper	$ 879	$1,265
Current maturities of long-term debt and other financing obligations	599	1,799
Notes payable	67	139
Short-term credit facility	—	111
	$1,545	$3,314

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

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%	495(2)	448	2009
June	El Paso	Senior notes(3)	6.14%	575	558	2007
June	El Paso	Notes(4)	7.875%	500	495	2012
June	EPNG	Notes(4)	8.375%	300	297	2032
June	TGP	Notes	8.375%	240	238	2032
July	Utility Contract Funding(1)	Senior secured notes	7.944%	829	822	2016

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	Field Services	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
Jan.-June	El Paso CGP	Long-term debt	Variable	75	75	2002
Jan.-June	Various	Long-term debt	Various	28	28	2002
July	El Paso CGP	Long-term debt	Variable	55	55	2002
July	El Paso(5)	Long-term debt	7.00%	15	10	2011
July	El Paso(5)	Long-term debt	7.875%	10	7	2012
August	El Paso(5)	Long-term debt	7.875%	15	12	2012
August	El Paso(5)	Long-term debt	7.00%	5	4	2011
August	El Paso(5)	Long-term debt	6.75%	5	4	2009
August	El Paso(5)	Long-term debt	7.625%	5	4	2011
July-Aug.	El Paso CGP	Long-term debt	Variable	44	44	2010-2028

(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 June 30, 2002, and includes a $45 million change in value due to a change in the Euro to U.S. dollar foreign currency exchange rate from the issuance date to June 30, 2002.

(3) These senior notes relate to an offering of 11.5 million 9% equity security units, which consist of forward purchase contracts on El Paso common stock to be settled on August 16, 2005. See Note 13 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.

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

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. 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. The interest rate under both of these facilities varies based on our senior unsecured debt rating, and as of June 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 June 30, 2002, there were no borrowings outstanding, and we have issued $450 million of letters of credit under the $1 billion facility.

12. Commitments and Contingencies

Legal Proceedings

We and several of our subsidiaries were named defendants in eleven purported class action, municipal or individual lawsuits, filed in California state courts (a list of the *California* cases is included in Part II, Item 1, Legal Proceedings). The eleven suits contend that our entities acted improperly to limit the construction of new pipeline capacity to California and/or to manipulate the price of natural gas sold into the California marketplace. The lawsuits have been consolidated before a single judge and are at the preliminary pleading stages with trial not anticipated until late 2003 at the earliest. We and our directors also have been named in a shareholder derivative action, contending that our directors failed to prevent the conduct alleged in several of these lawsuits. The derivative suit originally was filed in California, but was dismissed and refiled in Texas in March 2002. In addition, one of our subsidiaries also has been named a defendant in two lawsuits challenging the validity of long-term power contracts entered into by the California Department of Water Resources in early 2001. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

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

Beginning in July 2002, several purported shareholder class action suits alleging violations of federal securities laws have been filed against us and several of our officers in federal court in Houston (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.

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 to EPNG. The Notice alleged five probable violations of its regulations (a list of the alleged five probable violations is included in Part II, Item 1, Legal Proceedings), proposed fines totaling $2.5 million and proposed corrective actions. In October 2001, EPNG filed a detailed response with the Office of Pipeline Safety disputing each of the alleged violations. 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. We are cooperating with the National Transportation Safety Board in an investigation into the facts and circumstances concerning the possible causes of the rupture. In addition, a number of personal injury and wrongful death lawsuits were filed against us in connection with the rupture. Several of these suits have been settled, with payments fully covered by insurance. Seven Carlsbad lawsuits remain, with one of the seven having reached a contingent settlement within insurance coverage (a list of the remaining *Carlsbad* lawsuits is included in Part II, Item 1, Legal Proceedings).

In 1997, a number of our subsidiaries were named defendants in actions brought by Jack Grynberg on behalf of the U.S. Government under the False Claims Act. Generally, these complaints allege an industry-wide conspiracy to 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. These matters have been consolidated for pretrial purposes (In re: Natural Gas Royalties *Qui Tam* Litigation, U.S. District Court for the District of Wyoming, filed June 1997). In May 2001, the court denied the defendants' motions to dismiss.

A number of our subsidiaries were named defendants in *Quinque Operating Company, et al v. Gas Pipelines and Their Predecessors, et al*, filed in 1999 in the District Court of Stevens County, Kansas. This class action complaint alleges that the defendants mismeasured natural gas volumes and heating content of natural gas on non-federal and non-Native American lands. The Quinque complaint was transferred to the same court handling the Grynberg complaint and has now been sent back to Kansas State Court for further proceedings. A motion to dismiss this case is pending.

In compliance with the 1990 amendments to the Clean Air Act, we use the gasoline additive, methyl tertiary-butyl ether (MTBE), in some of our gasoline. We also produce, buy, sell and distribute MTBE. A number of lawsuits have been filed throughout the U.S. regarding MTBE's potential impact on water supplies. We are currently one of several defendants in five such lawsuits in New York. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

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

For each of our outstanding legal matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we establish the necessary accruals. As of June 30, 2002, we had reserves totaling $100 million for all outstanding legal matters, including $1 million reserved for our discontinued coal mining operations.

While the outcome of our outstanding legal matters cannot be predicted with certainty, based on the information known to date 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. As new information 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.

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 June 30, 2002, we had a reserve of approximately $521 million, including approximately $492 million for expected remediation costs and associated onsite, offsite and groundwater technical studies, which we anticipate incurring through 2027 and approximately $29 million for related environmental litigation costs. The reserve includes $15 million for discontinued coal operations. 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.

Since 1988, our subsidiary, TGP, has been engaged in an internal project to identify and deal with the presence of polychlorinated biphenyls (PCBs) and other substances, including those on the Environmental Protection Agency's (EPA) List of Hazardous Substances, at compressor stations and other facilities it operates. While conducting this project, TGP has been in frequent contact with federal and state regulatory agencies, both through informal negotiation and formal entry of consent orders, to ensure that its efforts meet regulatory requirements. TGP executed a consent order in 1994 with the EPA, governing the remediation of the relevant compressor stations and is working with the EPA, and the relevant states regarding those remediation activities. TGP is also working with the Pennsylvania and New York environmental agencies regarding remediation and post-remediation activities at the Pennsylvania and New York stations.

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

In May 1995, following negotiations with its customers, TGP filed 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 June 30, 2002, TGP has over-collected PCB costs by approximately $113 million for which it has established a non-current liability. 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. Presently, TGP estimates the future refund obligation, at the conclusion of the remediation process, to be approximately $50 million.

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.

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

We have been designated and have received notice that we could be designated, or have been asked for information to determine whether we could be designated, as a Potentially Responsible Party (PRP) with respect to 54 active sites under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) or state equivalents. We have sought to resolve our liability as a PRP at these CERCLA sites, as appropriate, through indemnification by third parties and settlements which provide for payment of our allocable share of remediation costs. As of June 30, 2002, we have estimated our share of the remediation costs at these sites to be between $31 million and $170 million and have provided reserves that we believe are adequate for such costs. Since the clean-up costs are estimates and are subject to revision as more information becomes available about the extent of remediation required, and because in some cases we have asserted a defense to any liability, our estimates could change. Moreover, liability under the federal CERCLA statute is joint and several, meaning that we could be required to pay in excess of our pro rata share of remediation costs. Our understanding of the financial strength of other PRPs has been considered, where appropriate, in determining our estimated liabilities.

While the outcome of our outstanding environmental matters cannot be predicted with certainty, based on the information known to date 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 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 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. For a further discussion of specific environmental matters, see *Legal Proceedings* above.

Rates and Regulatory Matters

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

In late 1999, several of EPNG's customers filed complaints requesting that the FERC order EPNG to stop selling primary firm delivery point capacity at the Southern California Gas Company Topock delivery point in excess of the downstream capacity available at that point and to stop overselling firm mainline capacity on the east-end of its mainline system. Several conferences and meetings were held during the summer of 2000. They failed to produce a settlement. In October 2000, the FERC ordered EPNG to make a one time allocation of capacity at the Southern California Gas Company Topock delivery point among affected firm shippers, but deferred action on east-end and system wide capacity allocation issues. In February 2001, the FERC accepted EPNG's tariff filing affirming the results of the Topock delivery point allocation process and directed EPNG to formulate a system-wide capacity allocation methodology to be addressed in EPNG's Order No. 637 proceeding. In March 2001, EPNG filed its proposed system-wide allocation methodology with the FERC. In April 2001, the February 2001 order was appealed by a customer to the U.S. Court of Appeals for the 9th Circuit, which dismissed the appeal in its entirety on July 22, 2002. In July 2001 and August 2001, technical conferences were conducted by the FERC on EPNG's system-wide capacity allocation proposal, after which the parties submitted position papers to the FERC regarding the appropriate method for allocating receipt point capacity on EPNG's system.

Two groups of EPNG's customers, those within California and those east of California, have filed complaints against EPNG with the FERC. In July 2001, twelve parties composed of California customers, natural gas producers and natural gas marketers, filed a complaint alleging that EPNG's full requirements contracts with its east of California customers should be converted to contracts with specific volumetric entitlements, that EPNG should be required to expand its interstate pipeline system and that firm shippers who experience reductions in their nominated gas volumes should be awarded demand charge credits. Also, in July 2001, ten parties, most of which are east of California full requirements contract customers, filed a complaint against EPNG with the FERC, alleging that EPNG violated the Natural Gas Act of 1938 and breached its contractual obligations by failing to expand its system in order to serve the needs of the full requirements contract shippers. The complainants requested that the FERC require EPNG to show cause why it should not be required to augment its system capacity. On May 31, 2002, the FERC issued an order in which it required, among other things that:

- EPNG's full requirements contracts, except those with its small volume customers, be converted to contract demand (CD) contracts, *i.e.,* contracts with maximum volumetric entitlements;
- CD customers be assigned specific receipt point rights, thereby replacing system-wide receipt points on EPNG's system;
- EPNG file an application to add compression to its Line 2000 project, thereby adding up to 320 million cubic feet per day of additional capacity to its system;
- EPNG allow its California delivery points to be utilized as receipt points on a secondary firm basis for the benefit of markets east of California;
- EPNG's 1996 rate settlement remain in effect for the remainder of its term, except as necessary to effectuate the changes required by the order;
- EPNG be required to give demand charge credits when EPNG is unable, except for reasons of force majeure, to schedule confirmed, firm nominations; and
- EPNG refrain from entering into new firm contracts until it has demonstrated that it has adequate capacity on its system to do so.

The Order established November 1, 2002, as the date on which the new CD contracts, demand charge credits, and receipt point entitlements will go into effect. On July 1, 2002, a number of parties to the proceedings filed requests for rehearing of various aspects of the order. Also on July 1, 2002, EPNG filed a request for clarification of the details involved in implementing the requirements of the order. At its July 17, 2002 open meeting, the FERC reaffirmed that the parties had until July 31, 2002, to establish capacity allocation levels among themselves on a voluntary basis and, absent any such voluntary agreement, the FERC itself will establish capacity levels by customer. On July 30, 2002, at the request of several parties, the FERC extended the deadline for the full requirements customers to bid for capacity turned back by other shippers to August 9, 2002. On that date, we received several bids from California shippers. The full requirements shippers, however, did not submit bids, taking the position that the turnback process could not go forward until the FERC had issued an order resolving disputes regarding the allocation to them of unsubscribed capacity on the system. In our report to the FERC dated August 1, 2002, we advised the FERC that, in order to move the conversion process from full requirements to CD service forward, it appears that the FERC will be required to issue an order establishing entitlements for the full requirements shippers to our unsubscribed, sustainable capacity. EPNG's customers subsequently filed responses disputing the basis upon which EPNG believes capacity on its system must be allocated. Although we and our customers have worked diligently to achieve an allocation of unsubscribed capacity among the full requirements shippers who are being required to convert to CD service, the full requirements shippers and the pipeline continue to hold a different view as to how this allocation should be accomplished. The needs of the full requirements shippers can be met through a combination of unsubscribed capacity, California receipt rights, turnback capacity from other shippers, and an appropriately sized expansion.

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, at which interested parties were given an opportunity to comment further on the NOPR. Following the conference, additional comments were filed by our pipeline subsidiaries and others. We cannot predict the outcome of the NOPR, but adoption of the regulations in substantially the form proposed would, at a minimum, place additional administrative and operational burdens on us.

On July 17, 2002, the FERC issued a Notice of Inquiry (NOI) that seeks comments regarding its policy, established in 1996, 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 undertaking a review of whether negotiated rates should be capped, whether or not a pipeline's "recourse rate" (its cost of service based rate) continues to serve as a viable alternative and safeguard against the exercise of alleged pipeline market power, as well as other issues related to its negotiated rate program. Comments are due on September 25, 2002, with reply comments due on October 25, 2002. We cannot predict the outcome of this NOI.

On August 1, 2002, the FERC issued a NOPR requiring that all arrangements concerning the 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 must maintain a minimum proprietary capital balance of 30 percent, and the FERC regulated entity and its parent must maintain investment grade credit ratings. Comments on the NOPR are due on August 22, 2002. We cannot predict the outcome of this NOPR.

Also on August 1, 2002, the FERC's Chief Accountant issued, to be effective immediately, an Accounting Release providing guidance on how jurisdictional entities should account for money pool arrangements and the types of documentation that should be maintained for these arrangements. The Accounting Release sets forth the documentation requirements set forth in the NOPR for money pool arrangements, but does not address the requirements in the NOPR that as a condition for participating in money pool arrangements the FERC regulated entity must maintain a minimum proprietary capital balance of 30 percent and that the entity and its parent must have investment grade credit ratings. Requests for rehearing are due on September 3, 2002.

In June 2001, the Western Australia regulators issued a draft rate decision at lower than expected levels of rates 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 $198 million. EPIC Energy Australia has appealed a variety of issues related to the draft decision to the Western Australia Supreme Court. The appeal was heard at the Western Australia Supreme Court in November 2001, and a decision from the court is expected in the second half of 2002. If the draft decision rates are implemented, the new rates will adversely impact future operating results, liquidity and debt capacity, possibly reducing the value of our investment by up to $138 million. Additionally, EPIC Energy (WA) Nominees Pty. Ltd. has debt of approximately AUD$1.8 billion (U.S.$1 billion) maturing in March 2003. Possible delays in the timing of the Supreme Court decision and uncertainty of the future rates may impact this refinancing.

We are engaged in arbitration 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 in the fourth quarter of 2002. 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 arbitration proceeding by the PUC could have a negative impact on our ongoing operations and prospects in this business.

El Paso Merchant Energy L.P. (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.

On May 21 and 22, 2002, the FERC issued additional 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 grand jury subpoena for documents concerning round trip or wash trades. We are conducting due diligence and plan to cooperate fully with these requests.

While the outcome of our rates and regulatory matters cannot be predicted with certainty, based on the information known to date 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. As new information 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.

Other Commercial Commitments

In 2001, we 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 under the five time-charter agreements is approximately $2.5 billion over the term of the time charters. 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

In December 2001, Enron Corp. and a number of its subsidiaries, including Enron North America Corp. and Enron Power Marketing, Inc., filed for Chapter 11 bankruptcy protection in the United States Bankruptcy Court for the Southern District of New York. We had contracts with Enron North America, Enron Power Marketing and other Enron subsidiaries for, among other things, the transportation of natural gas and natural gas liquids, the trading of physical gas, power, petroleum and financial derivatives. We established reserves for potential losses related to the receivables from our transportation contracts, as well as the positions and receivables under our marketing and trading contracts that we believe are adequate. In addition, we have terminated most of our trading-related contracts, and Enron has rejected many of its capacity contracts on our pipeline systems. We believe our termination of the trading contracts was proper and in accordance with the terms of these contracts. We, like other creditors, are discussing with Enron the extent of our damage claims against various Enron entities.

Affiliates of Enron hold both short-term and long-term capacity on several of our pipeline systems. While some transportation contracts between various Enron entities with EPNG or TGP have been rejected, we are uncertain as to Enron's intent to maintain or release capacity associated with contracts on other El Paso pipeline entities and also Enron's ability to honor the terms of their contracts. The Court has established August 19, 2002, as the deadline for Enron to assume or reject contracts with some of our subsidiaries. Future revenue related to these capacity contracts will depend upon the outcome of Enron's bankruptcy proceedings and our pipelines' ability to re-market or otherwise maximize the value of the rejected or released capacity. We do not presently know the precise values that will be received by our pipelines as a result of these efforts.

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.

In May 2002, due to the contracting party's failure to meet its contractual obligations, El Paso Global Networks Company (EPGN) terminated a series of agreements with a third party, which provided for construction and maintenance of a fiber optic telecommunications system. The third party disputed EPGN's right to terminate the agreements. Subsequently, EPGN notified the third party of its intent to arbitrate a resolution to the agreements. Arbitration hearings are expected to commence in the third quarter of 2002. Although the outcome of the arbitration or any subsequent litigation 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 invested capital of $109 million at June 30, 2002.

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 quarter 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 upcoming presidential election. 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 22% devaluation of the local currency against the U.S. dollar during the second 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. We currently believe that the economic difficulties in Brazil will not have a material adverse effect on our financial position, results of operations or cash flows. However, we will continue to monitor the economic situation, and it is possible that future developments in Brazil could cause us to reassess our exposure.

13. 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 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. Total notes 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. 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. In June 2002, we recorded $45 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 unit 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.

Other

In August 2002, we will be required to issue 12,184,480 shares of our common stock under our FELINE PRIDES[SM] program. The proceeds from this stock issuance will consist of a combination of cash and the return of our existing senior debentures that were issued in 1999 and are currently outstanding. Total proceeds will be approximately $460 million, of which approximately $25 million is estimated to be cash. The proceeds will be recorded as common stock and additional paid in capital.

Preferred Stock

As part of our balance sheet enhancement plan announced in December 2001, we completed amendments to our Chaparral and Gemstone agreements 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.

14. 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. During the quarter, 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 measure segment performance using earnings before interest expense and income taxes (EBIT). The following are our segment results as of and for the periods ended June 30:

	Quarter Ended June 30, 2002					
	Pipelines	Production	Merchant Energy	Field Services	Corporate & Other[1]	Total
	(In millions)					
Revenues from external customers	$ 567	$156	$1,989[2]	$263	$ 12	$2,987
Intersegment revenues	62	404	(643)[2]	238	(61)	—
Restructuring costs	1	—	11	1	50	63
Ceiling test charges	—	234	—	—	—	234
Operating income (loss)	274	4	(28)	26	(57)	219
EBIT	323	7	60	54	(33)	411

	Quarter Ended June 30, 2001					
	Pipelines	Production	Merchant Energy	Field Services	Corporate & Other[1]	Total
	(In millions)					
Revenues from external customers	$568	$ —	$2,437[2]	$622	$ 130	$3,757
Intersegment revenues	84	588	(748)[2]	115	(39)	—
Merger-related costs and asset impairments	226	—	58	9	308	601
Operating income (loss)	31	286	17	40	(417)	(43)
EBIT	69	289	137	55	(397)	153

(1) Includes our Corporate and telecommunication activities, eliminations of intercompany transactions and in 2001, our retail business.

(2) Merchant Energy revenues take into account the adoption of EITF Issue No. 02-3, which requires us to report all physical sales of energy commodities on a net basis. See Note 1 regarding the adoption of this Issue.

	Six Months Ended June 30, 2002					
	Pipelines	Production	Merchant Energy	Field Services	Corporate & Other(1)	Total
	(In millions)					
Revenues from external customers	$1,214	$311	$4,656(2)	$537	$ 24	$6,742
Intersegment revenues	118	799	(1,299)(2)	504	(122)	—
Restructuring costs and asset impairments	1	—	353	1	50	405
Ceiling test charges	—	267	—	—	—	267
Operating income (loss)	619	177	85	64	(71)	874
EBIT	722	183	153	105	(39)	1,124

	Six Months Ended June 30, 2001					
	Pipelines	Production	Merchant Energy	Field Services	Corporate & Other(1)	Total
	(In millions)					
Revenues from external customers	$1,283	$239	$4,626(2)	$1,269	$ 307	$7,724
Intersegment revenues	161	920	(1,032)(2)	225	(274)	—
Merger-related costs and asset impairments	315	63	192	38	1,152	1,760
Operating income (loss)	325	474	187	60	(1,300)	(254)
EBIT	402	474	394	91	(1,277)	84

(1) Includes our Corporate and telecommunication activities, eliminations of intercompany transactions and in 2001, our retail business.

(2) Merchant Energy revenues take into account the adoption of EITF Issue No. 02-3, which requires us to report all physical sales of energy commodities on a net basis. 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 June 30,		Six Months Ended June 30,	
	2002	2001	2002	2001
	(In millions)			
Total EBIT	$ 411	$ 153	$1,124	$ 84
Interest and debt expense	(359)	(291)	(666)	(586)
Minority interest	(43)	(56)	(83)	(118)
Income taxes	(1)	63	(119)	98
Income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	$ 8	$(131)	$ 256	$(522)

	June 30, 2002	December 31, 2001
	(In millions)	
Pipelines	$14,660	$14,443
Production	7,579	8,458
Merchant Energy	18,402	17,317
Field Services	2,882	3,581
Corporate and other	6,245	3,984
Total segment assets	49,768	47,783
Discontinued operations	235	388
Total consolidated assets	$50,003	$48,171

15. Investments in Unconsolidated Affiliates and Related Party Transactions

We hold investments in various affiliates which we account for using the equity method of accounting. Summarized financial information of our proportionate share of unconsolidated affiliates below includes affiliates in which we hold a less than 50 percent interest as well as those in which we hold a greater than 50 percent interest. Our proportional shares of the unconsolidated affiliates in which we hold a greater than 50 percent interest had net income of $6 million and $9 million for the quarters ended, and $16 million and $25 million for the six months ended June 30, 2002 and 2001.

	Quarter Ended June 30,		Six Months Ended June 30,	
	2002	2001	2002	2001
	(In millions)			
Operating results data				
Operating revenues	$689	$928	$1,142	$1,409
Operating expenses	479	748	782	1,049
Income from continuing operations	117	83	160	171
Net income	117	83	160	163

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 June 30, 2002 and December 31, 2001, the outstanding balance on these securities, plus accrued interest, was $132 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 control. In connection with the elimination of these triggers, we issued a direct guarantee supporting Gemstone's notes in the amount of $950 million.

Chaparral

We have a credit facility with Chaparral that allows Chaparral to borrow up to $925 million from us at a variable interest rate for their capital programs and working capital needs. The outstanding balance, plus accrued interest, owed to us under this credit facility was $788 million and $552 million at June 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 June 30, 2002 and December 31, 2001.

In April 2002, we completed amendments to the Chaparral agreements by eliminating the stock price and credit rating triggers and reducing the value of mandatorily convertible preferred stock that was held in a share trust. In connection with the elimination of these triggers, we issued a direct guarantee supporting Chaparral's notes totaling approximately $1 billion.

El Paso Energy Partners

In April 2002, we sold midstream assets to El Paso Energy Partners for total consideration of $735 million. Net proceeds were approximately $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.

In July 2002, we entered into a letter of intent with El Paso Energy Partners for the proposed sale of an estimated $782 million for a series of midstream assets including:

- substantially all of our natural gas gathering, processing and treating assets in the San Juan Basin of New Mexico;
- a 35-mile, 20-inch natural gas pipeline and a 16-mile, 12-inch oil pipeline originating on the Chevron/BHP "Typhoon" platform in the Green Canyon area of the Gulf of Mexico; and
- over 500 miles of NGL pipelines and a related fractionation facility in Texas.

This proposed 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. Both our Board and El Paso Energy Partners' Board also received fairness opinions on the transaction. This transaction is subject to customary regulatory review and approval. The closing of the sale is anticipated by the end of 2002.

16. Minority Interests

Clydesdale and Trinity River. In July 2002, we completed the amendments to the Clydesdale (also known as Mustang) 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 S&P and Moody's. We completed a similar amendment for our Trinity River (also known as Red River) agreements in March 2002.

Coastal Oil & Gas Resources Preferred Stock. In July 2002, we repurchased from an unaffiliated investor, 50,000 shares representing all outstanding preferred stock in Coastal Oil & Gas Resources, Inc., our wholly owned subsidiary, for $50 million plus accrued and unpaid dividends.

Coastal Limited Ventures Preferred Stock. In July 2002, we repurchased from 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 an unaffiliated investor, in 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.

17. 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 present value, and the same amount is added to the recorded value of the asset and is amortized over the asset's remaining useful life. The provisions of SFAS No. 143 are effective for fiscal years beginning after June 15, 2002. We are currently evaluating the effects of this statement.

Reporting Gains and Losses from the Early Extinguishment of Debt

In April 2002, the FASB issued SFAS No. 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections.* This statement addresses how to report gains or losses resulting from the early extinguishment of debt. Under current accounting rules, our non-rate regulated entities report any gains or losses on early extinguishment of debt as extraordinary items. When we adopt SFAS No. 145, we will be required to evaluate whether the debt extinguishment is truly extraordinary in nature. If we routinely extinguish debt early, the gain or loss will be included in income from continuing operations. This statement will be effective for our 2003 year-end reporting.

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 that are associated with a restructuring, discontinued operations, plant closings or other exit or disposal activities. The provisions of this statement are effective for fiscal years beginning after December 31, 2002 and will impact any exit or disposal activities initiated after January 1, 2003.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations(1)

The information contained in Item 2 updates, and you should read it in conjunction with, information disclosed in our Annual Report on Form 10-K filed March 15, 2002, in addition to the financial statements and notes presented in Item 1, Financial Statements, of this Quarterly Report on Form 10-Q.

Recent Developments

In December 2001, we announced a plan to strengthen our capital structure and enhance our liquidity, and in May 2002, we announced a plan to limit our investment in, and exposure to energy trading and to focus our activities and investment in core natural gas businesses. Since the announcement of these plans, we have:

- sold or contracted to sell, approximately $2.5 billion of assets;
- issued approximately $2.5 billion of common stock and equity security units;
- eliminated or renegotiated approximately $4 billion of rating triggers;
- reduced annual operating expenses by $300 million; and
- implemented working capital and credit limits on our trading business.

In addition to these steps, beginning in 2003, we intend to fund our capital expenditures with operating cash flow from our core businesses, reduce 2003 capital spending and sell up to $2 billion in non-strategic assets to further reduce our debt.

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 of these 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.

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

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

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

Results of Operations

Our results of operations, along with the impact by segment of the restructuring and merger-related costs, asset impairments and other charges, are presented below. Pro-forma amounts should not be used as a substitute for amounts reported under generally accepted accounting principles. They are presented solely to improve the understanding of the impact of the charges reported during the periods presented. The results are as follows (in millions):

	Quarter Ended June 30,					
	2002			2001		
	Reported	Charges[1]	Pro-forma	Reported	Charges[1]	Pro-forma
Pipelines	$ 323	$ 1	$ 324	$ 69	$ 246	$ 315
Production	7	234	241	289	7	296
Merchant Energy	60	11	71	137	130	267
Field Services	54	(9)	45	55	10	65
Segment EBIT	444	237	681	550	393	943
Corporate and other	(33)	50	17	(397)	411	14
Consolidated EBIT	411	287	698	153	804	957
Interest and debt expense	(359)	45	(314)	(291)	—	(291)
Minority interest	(43)	—	(43)	(56)	—	(56)
Income taxes	(1)	(106)	(107)	63	(259)	(196)
Discontinued operations, net of taxes	(67)	67	—	(3)	3	—
Extraordinary items, net of taxes	—	—	—	41	(41)	—
Accounting changes, net of taxes	14	(14)	—	—	—	—
Net income (loss)	$ (45)	$ 279	$ 234	$ (93)	$ 507	$ 414

	Six Months Ended June 30,					
	2002			2001		
	Reported	Charges[1]	Pro-forma	Reported	Charges[1]	Pro-forma
Pipelines	$ 722	$ 1	$ 723	$ 402	$ 335	$ 737
Production	183	267	450	474	70	544
Merchant Energy	153	353	506	394	264	658
Field Services	105	(9)	96	91	39	130
Segment EBIT	1,163	612	1,775	1,361	708	2,069
Corporate and other	(39)	50	11	(1,277)	1,255	(22)
Consolidated EBIT	1,124	662	1,786	84	1,963	2,047
Interest and debt expense	(666)	45	(621)	(586)	—	(586)
Minority interest	(83)	—	(83)	(118)	—	(118)
Income taxes	(119)	(226)	(345)	98	(529)	(431)
Discontinued operations, net of taxes	(86)	86	—	(2)	2	—
Extraordinary items, net of taxes	—	—	—	31	(31)	—
Accounting changes, net of taxes	168	(168)	—	—	—	—
Net income (loss)	$ 338	$ 399	$ 737	$ (493)	$1,405	$ 912

[1] Charges include restructuring and merger-related costs, asset impairments, ceiling test charges, changes in accounting estimates, discontinued operations, extraordinary items, cumulative effect of accounting changes, foreign exchange loss and other non-recurring gains. See Item 1, Financial Statements, for further discussions of these charges.

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 evaluate our segment performance based on EBIT. Operating revenues and expenses by segment include intersegment revenues and expenses which are eliminated in consolidation. Because changes in energy commodity prices have a similar impact on both our operating revenues and cost of products sold from period to period, we believe that gross margin (revenue less cost of sales) provides a more accurate and meaningful basis for analyzing operating results for the trading and refining portions of Merchant Energy and for the Field Services segment. We have reclassified our historical coal mining operations from Merchant Energy to discontinued operations in our financial statements. All periods have been adjusted to reflect these changes. For a further discussion of our individual segments, see Item 1, Financial Statements, Note 14, as well as our Annual Report on Form 10-K for the year ended December 31, 2001. The segment EBIT results for the periods ended June 30 presented below include the charges discussed above:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2002	2001	2002	2001
	(In millions)			
Pipelines	$ 323	$ 69	$ 722	$ 402
Production	7	289	183	474
Merchant Energy	60	137	153	394
Field Services	54	55	105	91
Segment total	444	550	1,163	1,361
Corporate and other, net	(33)	(397)	(39)	(1,277)
Consolidated EBIT	$ 411	$ 153	$1,124	$ 84

Pipelines

Our Pipelines segment holds our interstate transmission businesses. Pipeline results are relatively stable, but can be subject to variability from a number of factors, such as weather conditions, including those conditions that may impact the amount of power produced by natural gas fired turbines compared to power generated by less costly hydro-electric methods, as well as gas supply availability which can displace the pipeline's delivery capabilities to the markets they serve. Results can also be impacted by the ability to market excess fuel which is influenced by a pipeline's rate of recovery for fuel for use and efficiencies of the pipeline's compression equipment. Future revenues may also be impacted by expansion projects in our service areas, competition by other pipelines for those expansion needs and regulatory impacts on rates. Results of our Pipelines segment operations were as follows for the periods ended June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2002	2001	2002	2001
	(In millions, except volume amounts)			
Operating revenues	$ 629	$ 652	$1,332	$1,444
Operating expenses	(355)	(621)	(713)	(1,119)
Other income	49	38	103	77
EBIT	$ 323	$ 69	$ 722	$ 402

	Quarter Ended June 30,		Six Months Ended June 30,	
	2002	2001	2002	2001
	(In millions, except volume amounts)			
Throughput volumes (BBtu/d)[1]				
TGP	4,235	4,092	4,510	4,566
EPNG and MPC	4,046	4,552	4,124	4,688
ANR	3,604	3,776	3,691	3,857
CIG and WIC	2,429	2,284	2,608	2,357
SNG	1,780	1,657	2,030	1,943
Equity investments (our ownership share)	2,695	2,414	2,695	2,351
Total throughput	18,789	18,775	19,658	19,762

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

Second Quarter 2002 Compared to Second Quarter 2001

Operating revenues for the quarter ended June 30, 2002, were $23 million lower than the same period in 2001. The decrease was primarily due to the impact of lower prices on natural gas and liquids sales, including natural gas produced in our pipeline operations, and sales of excess natural gas recovered, in excess of the amounts used in operations. Also contributing to the decrease were the favorable resolution of regulatory issues related to natural gas purchase contracts in 2001 and lower throughput to California and other western states and to the northeast due to lower electric generation demand and milder weather in these areas in 2002. Additionally, lower transportation revenues from capacity sold under short-term contracts and the sale of our Midwestern Gas Transmission system in April 2001 contributed to the decrease. These decreases were partially offset by revenues from transmission system expansion projects placed in service in 2001 and 2002, higher reservation revenues on the EPNG system as a result of a larger portion of its capacity sold at maximum tariff rates compared to the same period in 2001 and revenues from the Elba Island liquefied natural gas (LNG) facility which was placed in service in December 2001.

Operating expenses for the quarter ended June 30, 2002, were $266 million lower than the same period in 2001 primarily as a result of 2001 merger-related charges of $226 million related to our merger with Coastal and a 2001 change in estimate of $20 million for additional environmental remediation liabilities. Also contributing to the decrease were lower corporate overhead allocations in the second quarter of 2002, and lower compressor operating costs on the EPNG system resulting from lower electric prices. The decrease was partially offset by additional 2002 accruals on estimated liabilities to assess and remediate our environmental exposure due to an ongoing evaluation of our operating facilities, higher operating expenses due to the Elba Island LNG facility being in service in 2002 and increases to our reserve for bad debts in 2002 related to the bankruptcy of Enron Corp.

Other income for the quarter ended June 30, 2002, was $11 million higher primarily due to the resolution of uncertainties associated with the sales of our interests in the Empire State and Iroquois pipeline systems and our Gulfstream pipeline project in 2001. Also contributing to the increase were gains from the sales of non-pipeline assets in 2002.

Six Months Ended 2002 Compared to Six Months Ended 2001

Operating revenues for the six months ended June 30, 2002, were $112 million lower than the same period in 2001. The decrease was primarily due to the impact of lower prices on sales of excess natural gas recovered, in excess of the amounts used in operations, natural gas and liquids sales, including sales of natural gas produced. Also contributing to the decrease were lower transportation revenues from capacity sold under short-term contracts and lower throughput to California and other western states and to the northeast due to lower electric generation demand and milder weather in these areas in 2002. Additionally, the favorable resolution of regulatory issues related to natural gas purchase contracts in 2001 and the sale of our Midwestern

Gas Transmission system in April 2001 contributed to the decrease. These decreases were partially offset by higher reservation revenues on the EPNG system as a result of a larger portion of its capacity sold at maximum tariff rates compared to the same period in 2001, revenues from transmission system expansion projects placed in service in 2001 and 2002 and revenues from the Elba Island LNG facility which was placed in service in December 2001.

Operating expenses for the six months ended June 30, 2002, were $406 million lower than the same period in 2001 primarily as a result of 2001 merger-related charges related to our merger with Coastal of $315 million and a 2001 change in estimate of $20 million for additional environmental remediation liabilities. Also contributing to the decrease were lower compressor operating costs on the EPNG system resulting from lower electric prices, lower corporate overhead allocations and lower employee benefit costs in 2002, as well as lower operating expenses due to cost efficiencies following the merger with Coastal. The decrease was partially offset by increases to our reserve for bad debts in 2002 related to the bankruptcy of Enron Corp., additional 2002 accruals on estimated liabilities to assess and remediate our environmental exposure due to an ongoing evaluation of our operating facilities, and higher operating expenses due to the Elba Island LNG facility being placed in service in 2002.

Other income for the six months ended June 30, 2002, was $26 million higher primarily due to a gain on the sale of pipeline expansion rights in February 2002, the resolution of uncertainties associated with the sales of our interests in the Empire State and Iroquois pipeline systems and our Gulfstream pipeline project in 2001, as well as gains from the sales of non-pipeline assets in 2002.

Production

Our Production segment conducts our natural gas and oil exploration and production activities. 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. Results of our Production segment operations were as follows for the periods ended June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2002	2001	2002	2001
	(In millions, except volumes and prices)			
Natural gas	$ 441	$ 501	$ 921	$ 981
Oil, condensate and liquids	115	80	197	166
Other	4	7	(8)	12
Total operating revenues	560	588	1,110	1,159
Transportation and net product costs	(33)	(19)	(55)	(56)
Total operating margin	527	569	1,055	1,103
Operating expenses	(523)	(283)	(878)	(629)
Other income	3	3	6	—
EBIT	$ 7	$ 289	$ 183	$ 474
Volumes and prices				
Natural gas				
Volumes (MMcf)	120,020	139,277	253,286	273,221
Average realized prices[(1)] ($/Mcf)	$ 3.45	$ 3.49	$ 3.46	$ 3.49

	Quarter Ended June 30,		Six Months Ended June 30,	
	2002	2001	2002	2001
	(In millions, except volumes and prices)			
Oil, condensate and liquids				
Volumes (MBbls)	4,966	3,353	9,954	6,487
Average realized prices[1] ($/Bbl)	$ 22.14	$ 22.98	$ 18.90	$ 25.12

[1] Net of transportation costs.

Second Quarter 2002 Compared to Second Quarter 2001

For the quarter ended June 30, 2002, operating revenues were $28 million lower than the same period in 2001 due to a decline in natural gas volumes in 2002 when compared to the same period of 2001. The decline in natural gas volumes is primarily a result of the first quarter 2002 sale of properties in Texas and Colorado. Partially offsetting the decrease was an increase in volumes for oil, condensate and liquids in 2002 when compared to the same period of 2001.

Transportation and net product costs for the quarter ended June 30, 2002, were $14 million higher than the same period in 2001 primarily due to a higher percentage of gas volumes subject to transportation fees.

Operating expenses for the quarter ended June 30, 2002, were $240 million higher than the same period in 2001 due to higher depletion expense in 2002 as a result of additional capital spending on assets in the full cost pool, increased oilfield services costs and non-cash full cost ceiling test charges totaling $234 million incurred in 2002, primarily for our Canadian full cost pool. The charge for the Canadian full cost pool resulted from a low daily posted price for natural gas of approximately $1.43 per MMBtu at the end of the second quarter. Partially offsetting these increases were write-downs in 2001 totaling $7 million of materials and supplies resulting from the ongoing evaluation of our operating standards and plans following the Coastal merger and lower severance and other taxes in 2002.

Six Months Ended 2002 Compared to Six Months Ended 2001

For the six months ended June 30, 2002, operating revenues were $49 million lower than the same period in 2001. The decrease was primarily due to a loss on derivative positions that no longer qualify as cash flow hedges under SFAS No. 133 because they were designated as hedges of anticipated future production from natural gas and oil properties that were sold in March 2002. Also contributing to the decrease was a decline in natural gas volumes and average realized oil, condensate and liquids prices in 2002 when compared to the same period of 2001. The decline in natural gas volumes is primarily a result of the first quarter 2002 sale of properties in Texas and Colorado. Partially offsetting the decrease was an increase in volumes for oil, condensate and liquids in 2002 when compared to the same period of 2001.

Operating expenses for the six months ended June 30, 2002, were $249 million higher than the same period in 2001 due to higher depletion expense in 2002 as a result of additional capital spending on assets in the full cost pool and non-cash full cost ceiling test charges totaling $267 million incurred in 2002 for our Canadian full cost pool and other international properties principally in Brazil, Turkey and Australia. Also contributing to the increase were increased oilfield services costs and higher corporate overhead allocations. Partially offsetting these increases were merger-related costs and other charges of $63 million incurred in 2001 related to our combined production operations, write-downs totaling $7 million of materials and supplies recognized in 2001 resulting from the ongoing evaluation of our operating standards and lower severance and other taxes in 2002.

Other income for the six months ended June 30, 2002, was $6 million higher than the same period in 2001 primarily due to a gain on the sale of non-full cost pool assets in south and east Texas in March 2002 and higher earnings in 2002 from Pescada, an equity investment in Brazil.

Merchant Energy

Our customer origination and trading activities, as well as our power, refining and chemical activities are conducted through our Merchant Energy segment. As part of the power operations of our Merchant Energy segment, we engage in power contract restructuring activities. These power contract restructurings are usually conducted through our unconsolidated affiliate, Chaparral, or other joint ventures. However, they may also involve restructuring of power plant facilities and related assets that are consolidated in our financial statements, as in the case of our Eagle Point Cogeneration and Mount Carmel restructuring transactions discussed in results of operations below.

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 the plan for our Merchant Energy segment include:

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

As a result of current circumstances surrounding the wholesale energy markets we have experienced weaker market fundamentals resulting in an elimination of industry participants and the disorderly liquidation of their trading portfolios. Additionally, changes in credit requirements have left several market participants less creditworthy, requiring greater use of credit support actions. These factors have resulted in lower trading profitability which we expect to continue for the remainder of 2002 and into 2003. In addition, our refining business has been adversely impacted over the past twelve months by the declining spreads between the lighter crudes, which are typically more expensive than the heavy crudes processed at our Aruba refinery. We expect this trend to continue into 2003.

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.

Energy-Related Price Risk Management Activities

As of June 30, 2002, the net fair value of our energy contracts was $1.7 billion. Of this amount, the net fair value of our trading-related energy contracts was $1.1 billion. Our trading activities generated margins during the six months ended June 30, 2002 and 2001 totaling $64 million and $477 million.

The following table details the net fair value of our energy contracts by year of maturity and valuation methodology as of June 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	$(62)	$ 427	$ 252	$151	$ 3	$ 771
Prices based on models and other valuation methods	143	90	32	23	19	307
Total trading contracts, net	81	517	284	174	22	1,078
Non-trading contracts[1]						
Prices actively quoted	38	(113)	(10)	183	125	223
Prices based on models and other valuation methods	40	78	75	140	87	420
Total non-trading contracts, net	78	(35)	65	323	212	643
Total energy contracts	$159	$ 482	$ 349	$497	$234	$1,721

[1] Non-trading energy contracts include derivatives from our power contract restructuring activities of $979 million and derivatives related to our natural gas and oil producing activities of $(336) 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 six months ended June 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	(298)	(191)	(489)
Initial recorded value of new contracts	71[(1)]	884[(1)]	955
Change in fair value of contracts	65	(509)	(444)
Changes in fair value attributable to changes in valuation techniques	(69)	—	(69)
Other	14	—	14
Net change in contracts outstanding during the period	(217)	184	(33)
Fair value of contracts outstanding at June 30, 2002	$1,078	$ 643	$1,721

(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 do not recognize 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.

Results of Operations

Below are Merchant Energy's operating results and an analysis of these results for the periods ended June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2002	2001	2002	2001
	(In millions, except volume amounts)			
Trading and refining gross margins	$ 63	$ 374	$ 720	$ 879
Operating and other revenues	244	86	406	219
Operating expenses	(335)	(443)	(1,041)	(911)
Other income	88	120	68	207
EBIT	$ 60	$ 137	$ 153	$ 394
Volumes[(1)]				
Physical				
Natural gas (BBtue/d)	13,639	9,187	13,431	10,912
Power (MMWh)	108,717	45,434	214,683	81,741
Crude oil and refined products (MBbls)	209,204	166,534	376,046	335,771
Financial settlements (BBtue/d)	201,637	186,860	212,133	217,060

(1) Volumes include those traded 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.

Second Quarter 2002 Compared to Second Quarter 2001

During the quarter ended June 30, 2002, we completed two significant transactions, one related to our Nejapa power facility and the other related to a long-term LNG supply contract. 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. In May 2002, we received final approval from the Norwegian and United States governments on an LNG purchase and sale agreement signed in October 2001 with a consortium of natural gas production companies led by Statoil ASA. The consortium will develop the Snøhvit Project in northern Norway, and we will receive LNG shipments equivalent to an estimated 91 billion cubic feet per year of natural gas during the 17-year term of the agreement with the possibility of a 3-year extension. The first delivery is scheduled to occur between October 2005 and October 2006. The Snøhvit agreement is a derivative under SFAS No. 133, which we were required to mark to its fair value when it was finalized. As a result, we recorded a $59 million gain in the second quarter of 2002 from this transaction.

For the quarter ended June 30, 2002, trading and refining gross margins were $311 million lower than the same period in 2001. The decrease was due to lower trading margins primarily due to a weaker trading environment and lower price volatility in the natural gas and power markets in the second quarter of 2002, partially offset by the $59 million gain on the Snøhvit transaction. Also contributing to the overall decrease were lower refining margins resulting from the lease of our Corpus Christi refinery and related assets to Valero in June 2001, lower spreads between the sales prices of refined products and underlying feedstock costs and lower throughput at the Aruba refinery. Lower revenues from our marine operations resulting from lower freight rates, a decrease in vessels owned and on charter and lower throughput at our marine terminals also contributed to the overall decrease in trading and refining margins.

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 June 30, 2002, operating and other revenues were $158 million higher than the same period in 2001. The increase resulted from revenues from domestic and international power facilities that were consolidated in the fourth quarter of 2001 and the first quarter of 2002, $90 million of revenues from the termination of the Nejapa power contract and higher management fees from Chaparral.

Operating expenses for the quarter ended June 30, 2002, were $108 million lower than the same period in 2001. The decrease was primarily a result of merger-related costs, changes in accounting estimates and asset impairments of $130 million recorded in the second quarter of 2001 associated with combining operations with Coastal. The decrease was partially offset by the consolidation of international and domestic power-related entities in the fourth quarter of 2001 and the first quarter of 2002 as well as higher operating expenses resulting from the expansion of our LNG business in 2002 and more extensive operations in Europe and Mexico in 2002 as compared to 2001.

Other income for the quarter ended June 30, 2002, was $32 million lower than the same period in 2001. The decrease was primarily the result of marketing, agency and technical services fees related to the development of the Macae power project in Brazil which were recorded in the second quarter of 2001 as well as the minority owner's interest in the gain from the termination of the Nejapa power contract of $13 million. Also, we had an increase in equity earnings from unconsolidated power projects in the second quarter of 2002.

Six Months Ended 2002 Compared to Six Months Ended 2001

During the six months ended June 30, 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 El Paso Merchant Energy L.P. (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 secured solely by the contracts and cash flows of UCF. The proceeds of the monetization will be reported as financing cash flow in the third quarter of 2002.

We also employed the principles of our power restructuring business in completing two contract terminations in the period — in the second quarter, the Nejapa transaction as discussed above, and in the first quarter, the Mount Carmel transaction. 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 six months ended June 30, 2002, trading and refining gross margins were $159 million lower than the same period in 2001. Contributing to this decrease was a decline in our marketing and trading activities primarily in natural gas and power principally resulting from a weaker trading environment and lower price volatility in the natural gas and power markets in the first half of 2002. The decrease in our trading activity was offset by the Eagle Point Cogeneration and Mount Carmel power contract restructurings described above and a $59 million gain from our Snøhvit LNG transaction. Also contributing to the overall decrease were lower refining margins resulting from the lease of our Corpus Christi refinery and related assets to Valero in June 2001, lower spreads between the sales prices of refined products and underlying feedstock costs and lower throughput at our Aruba refinery, lower revenues from vessels owned and on charter, and lower throughput at our marine terminals.

For the six months ended June 30, 2002, operating and other revenues were $187 million higher than the same period in 2001. The increase resulted from revenues from domestic and international power facilities that were consolidated in the fourth quarter of 2001 and the first quarter of 2002, $90 million of revenues from the termination of the Nejapa power contract in the second quarter of 2002 and higher management fees from Chaparral.

Operating expenses for the six months ended June 30, 2002, were $130 million higher than the same period in 2001. The increase resulted from a $342 million impairment of our power investments in Argentina in the first quarter of 2002, the consolidation of international and domestic power-related entities in the fourth quarter of 2001 and the first quarter of 2002, and higher operating expenses resulting from the expansion of our LNG business in 2002 and more extensive operations in Europe and Mexico in 2002 as compared to 2001. The increase was partially offset by merger-related costs, changes in accounting estimates and asset impairments of $264 million recorded in the second quarter of 2001 associated with combining operations with Coastal as well as lower fuel costs 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 six months ended June 30, 2002, was $139 million lower than the same period in 2001. The decrease was primarily the result of marketing, agency and technical services fees related to the development of the Macae power project in Brazil which were recognized in the second quarter of 2001, the minority owner's interest in the gain on the termination of the Nejapa power contract of $13 million and Chaparral's minority ownership interest in income earned on our Eagle Point Cogeneration restructuring transaction. Also contributing to the decrease were lower equity earnings on domestic power projects consolidated in the fourth quarter of 2001 and the first quarter of 2002. The power projects we consolidated in the fourth quarter of 2001 and the first quarter of 2002 are not wholly-owned by us. As a result, the minority owners interest in the income earned from these facilities, which we classify as other income, also reduced other income in the first six months of 2002.

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 over $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 the partnership, 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. 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.

With the completion of these 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 the partnership to offset, in part, the anticipated decrease in EBIT.

After the sale of the San Juan Basin 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.

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

	Quarter Ended June 30,		Six Months Ended June 30,	
	2002	2001	2002	2001
	(In millions, except volumes and prices)			
Gathering, treating and processing gross margins	$ 84	$ 145	$ 209	$ 295
Operating expenses	(58)	(105)	(145)	(235)
Other income	28	15	41	31
EBIT	$ 54	$ 55	$ 105	$ 91
Volumes and prices				
Gathering and treating				
Volumes (BBtu/d)	2,265	5,994	4,039	6,051
Prices ($/MMBtu)	$ 0.20	$ 0.14	$ 0.17	$ 0.14
Processing				
Volumes (inlet BBtu/d)	3,956	4,340	4,035	4,117
Prices ($/MMBtu)	$ 0.11	$ 0.16	$ 0.11	$ 0.17

Second Quarter 2002 Compared to Second Quarter 2001

Total gross margins for the quarter ended June 30, 2002, were $61 million lower than the same period in 2001. Gathering and treating margins decreased by $33 million primarily due to our sale of assets to El Paso Energy Partners in April 2002. The decrease in our processing margins was attributable to the sale of the Indian Basin processing plant to El Paso Energy Partners in April 2002 and lower natural gas and NGL prices in 2002 which unfavorably impacted our processing volumes and margins in the Rockies, south Louisiana and south Texas regions. Also contributing to the decrease in processing margins were higher processing costs associated with a processing arrangement at the Chaco processing facility entered into in the fourth quarter of 2001 with El Paso Energy Partners and the sale of our Dragon Trail processing plant in May 2002.

Operating expenses for the quarter ended June 30, 2002, were $47 million lower than the same period of 2001. The decrease was primarily due to $26 million of reduced operating and depreciation expenses largely attributable to our sale of assets to El Paso Energy Partners in April 2002, and $9 million in merger-related costs in 2001. Also contributing to the decrease was lower amortization of goodwill of $4 million due to the implementation of SFAS No. 142 in 2002.

Other income for the quarter ended June 30, 2002, was $13 million higher than the same period in 2001 primarily due to a $10 million gain recognized on the sale of our Dragon Trail processing plant and higher earnings in 2002 from our interest in El Paso Energy Partners, partially offset by an $8 million gain resulting from the sale of our 1.01 percent non-managing interest in the partnership in May 2001.

Six Months Ended 2002 Compared to Six Months Ended 2001

Total gross margins for the six months ended June 30, 2002, were $86 million lower than the same period in 2001. Gathering and treating margins decreased primarily due to our sale of assets to El Paso Energy Partners in April 2002. Excluding the impact of asset sales, gathering and treating margins were higher compared to last year due to the favorable resolution of fuel, rate and volume matters in the first quarter of 2002 and higher realized transportation rates in the first quarter of 2002 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. Partially offsetting these increases were lower natural gas prices in the San Juan Basin in 2002. Processing margins declined due to the sale of the Indian Basin processing plant to El Paso Energy Partners in April 2002 and lower natural gas and NGL prices in 2002 which unfavorably impacted our processing volumes and margins in the Rockies, south Louisiana and south Texas regions. Also contributing to the decrease in processing margins were 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 our Dragon Trail processing plant in May 2002.

Operating expenses for the six months ended June 30, 2002, were $90 million lower than the same period of 2001. The decrease was primarily due to $35 million of reduced operating and depreciation expenses largely attributable to our sale of assets to El Paso Energy Partners in April 2002 and in October 2001. Also contributing to the decrease were $38 million in merger-related costs in 2001 which include payments to El Paso Energy Partners related to FTC ordered sales of assets owned by the partnership, merger-related employee severance and relocation expenses following our merger with Coastal, as well as a decrease in goodwill amortization of $8 million in 2002 due to the implementation of SFAS No. 142.

Other income for the six months ended June 30, 2002, was $10 million higher than the same period in 2001 primarily due to a $10 million gain recognized on the sale of our Dragon Trail processing plant and higher earnings in 2002 from our interest in El Paso Energy Partners.

Corporate and Other, net

Corporate and other expenses, which include general and administrative activities as well as the operations of our telecommunications and other miscellaneous businesses, for the quarter and six months ended June 30, 2002, were $364 million and $1,238 million lower than the same periods in 2001. The decrease was primarily a result of $248 million and $1,152 million in merger-related charges for the quarter and six months ended June 30, 2001, in connection with our merger with Coastal, and additional costs for the quarter and six months ended June 30, 2001 of $90 million related to increased estimates of environmental remediation 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. Also contributing to the decrease was a write-down of $60 million for our investment in a telecommunications company in Brazil in the second quarter of 2001. Partially offsetting the decrease 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 for the Gemstone and Chaparral indentures.

We continue to evaluate the impact of the continuing decline in the telecommunications industry on our telecommunications business. These conditions and the credit and liquidity standing of many of the telecommunications industry participants have impacted our Chicago-based telecommunications facility, which we lease 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 in this facility with Global Crossing, which 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. Although the operating results from this facility are still positive, due to this event and the continuing decline in the financial condition of the remaining tenants, we have retained a consultant to assist us in determining the fair value of the building and its real estate potential. To the extent we determine the expected fair value of the facility at the end of the lease financing term is less than the residual value guarantee, the difference will be amortized over the remaining term of the financing. Despite the continued decline in the industry, our Texas-based metro transport business continues to show steady growth. Additionally, we received a favorable outcome in an arbitration proceeding with Southwestern Bell, although the arbitration ruling is still subject to the Texas PUC approval. Although we believe there is no current impairment in our metro business, we will continue to evaluate this business on a quarterly basis. At June 30, 2002, our net investment in the telecommunications business was $527 million.

Interest and Debt Expense

Interest and debt expense for the quarter and six months ended June 30, 2002, was $68 million and $80 million higher than the same periods in 2001. The increase was a result of higher long-term borrowings for ongoing capital projects, investment programs and operating requirements. Also contributing to the increase was a foreign currency loss of $45 million related to changes in value of our Euro notes issued in May 2002 based on changes in the foreign currency exchange rate. This increase was partially offset by repayment of short-term credit facilities and lower interest rates on short-term borrowings. We anticipate interest and debt expenses will continue to exceed last year's levels throughout the remainder of 2002.

Minority Interest

Minority interest expense for the quarter and six months ended June 30, 2002, was $13 million and $35 million lower than the same periods in 2001, primarily due to lower interest rates in 2002, partially offset by increased minority interest expense on Gemstone which was formed in November 2001.

Income Taxes

Income tax expense for the quarter and six months ended June 30, 2002, was $1 million and $119 million, resulting in effective tax rates of 11 percent and 32 percent. The quarter ended June 30, 2002, income tax expense was net of a tax benefit of approximately $2 million associated with taxes related to, and reclassified as, discontinued operations. The effective tax rate excluding the reclassification for the quarter ended June 30, 2002, was 32 percent. Our effective tax rates were different than the statutory rate of 35 percent primarily due to the following:

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

Income tax benefit for the quarter and six months ended June 30, 2001, was $63 million and $98 million, resulting in effective tax rates of 32 percent and 16 percent. The six months ended June 30, 2001 benefit was net of $110 million of tax expense associated with non-deductible merger charges and changes in our estimates of additional tax liabilities. The majority of these estimated additional liabilities were paid in 2001 and are being contested by us. The effective tax rate excluding these charges for the six months ended June 30, 2001 was 33 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.

Liquidity and Capital Resources

General

During the six months ended June 30, 2002, our cash and cash equivalents increased by $1.5 billion to approximately $2.7 billion. During the period, we generated an estimated $5.6 billion through a combination of cash-based earnings of $1.1 billion and the issuances of $3.5 billion long-term debt and $1.0 billion common stock. In addition, we generated approximately $1.3 billion through sales of natural gas and oil properties and midstream assets. From these cash inflows, we invested approximately $2.0 billion in fixed assets and investments, paid $1.5 billion on maturing debt issues, paid $0.9 billion, net, on short-term debt, paid $0.2 billion in dividends, and funded working capital needs of approximately $0.7 billion, principally related to margins and option premiums in our price risk management activities. Our operating cash flow from period to period is significantly impacted, either positively or negatively, by movements in commodity prices. For the remainder of 2002, we expect to meet our cash investing and financing needs, including the payment of dividends, through cash generated from earnings in our operating businesses, through additional financing transactions and through asset sales, as needed. However, our working capital inflows or outflows for the remainder of 2002 will be dependent on fluctuations in commodity prices as well as strategies we may implement to offset the impact of commodity price fluctuations on our cash flows. Other sources of liquidity at June 30, 2002, include our 364 day bank revolver of $3.0 billion and multiple-year bank revolver of $1.0 billion which are discussed below.

Cash From Operating Activities

Net cash provided by operating activities was $0.3 billion for the six months ended June 30, 2002, compared to net cash provided by operating activities of $2.7 billion for the same period in 2001. The decrease was primarily due to less cash generated through liquidations of price risk management assets in 2002, as well as more cash used to fund broker and over-the-counter margins. Our operating cash flow reductions also related to higher petroleum inventory in 2002. Partially offsetting these decreases were payments in 2001 related to the merger with Coastal.

Cash From Investing Activities

Net cash used in our investing activities was $626 million for the six months ended June 30, 2002, of which $7 million was used in investing activities by discontinued operations. Our investing activities consisted primarily of additions to property, plant, and equipment, including expenditures for developmental drilling and expansion and construction projects. Our additions to investments consisted mostly of short-term notes from unconsolidated affiliates, primarily related to a subsidiary of Chaparral. Cash inflows from investment-related activities included net proceeds from the sale of natural gas and oil properties located in east and south Texas and Colorado, the sale of midstream assets to El Paso Energy Partners, L.P., as well as the sale of a natural gas gathering system and a natural gas processing plant.

Cash From Financing Activities

Net cash provided by our financing activities was $1.8 billion for the six months ended June 30, 2002, of which $31 million was used in financing activities by discontinued operations. Cash provided from our financing activities included the issuance of long-term debt and issuances of common stock and equity security units. Cash used by our financing activities included payments made to retire long-term debt and other financing obligations, as well as repayments under our commercial paper and short-term credit facilities.

On July 17, 2002, we declared a quarterly dividend of $0.2175 per share on our common stock, payable on October 7, 2002, to stockholders of record on September 6, 2002. Also, during the six months ended June 30, 2002, El Paso Tennessee Pipeline Co., our subsidiary, paid dividends of $12 million on our Series A cumulative preferred stock, which is 8¼% per annum (2.0625% per quarter).

Liquidity

Our 2001 Annual Report on Form 10-K includes a detailed discussion of our liquidity, financing activities, contractual obligations and commercial commitments. The information presented below updates, and you should read it in conjunction with, the information disclosed in our 2001 Annual Report on Form 10-K.

Financing Activities

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

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%	495[3]	448	2009
June	El Paso	Senior notes[4]	6.14%	575	558	2007
June	El Paso	Notes[5]	7.875%	500	495	2012
June	EPNG	Notes[5]	8.375%	300	297	2032
June	TGP	Notes	8.375%	240	238	2032
July	Utility Contract Funding[2]	Senior secured notes	7.944%	829	822	2016

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	Field Services	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
Jan.-June	El Paso CGP	Long-term debt	Variable	75	75	2002
Jan.-June	Various	Long-term debt	Various	28	28	2002
July	El Paso CGP	Long-term debt	Variable	55	55	2002
July	El Paso[6]	Long-term debt	7.00%	15	10	2011
July	El Paso[6]	Long-term debt	7.875%	10	7	2012
August	El Paso[6]	Long-term debt	7.875%	15	12	2012
August	El Paso[6]	Long-term debt	7.00%	5	4	2011
August	El Paso[6]	Long-term debt	6.75%	5	4	2009
August	El Paso[6]	Long term debt	7.625%	5	4	2011
July-Aug.	El Paso CGP	Long-term debt	Variable	44	44	2010-2028

(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 June 30, 2002, and includes a $45 million change in value due to a change in the Euro to U.S. dollar foreign currency exchange rate from the issuance date to June 30, 2002.

(4) These senior notes relate to an offering of 11.5 million 9% equity security units, which consist of 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.

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

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 $1.0 billion and will be used to repay short-term borrowings and other financing obligations and for general corporate purposes.

In July 2002, UCF 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 UCF including obligations of PSEG 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 August 2002, we will be required to issue 12,184,480 shares of our common stock under our FELINE PRIDES[SM] program. The proceeds from this stock issuance will consist of a combination of cash and the return of our existing senior debentures that were issued by El Paso CGP in 1999 and are currently outstanding. Total proceeds will be approximately $460 million, of which approximately $25 million is estimated to be cash. The proceeds will be recorded as common stock and additional paid in capital.

Credit Facilities and Available Capacity

In February 2002, we filed a new shelf registration statement with the Securities and Exchange Commission that allows us to issue up to $3 billion in securities. Under this registration statement, we can issue a combination of debt, equity and other instruments, including trust preferred securities of 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 June 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 remain designated borrowers under this facility. 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. The interest rate under both of these facilities varies based on our senior unsecured debt rating, and as of June 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 June 30, 2002, there were no borrowings outstanding, and we have issued $450 million of letters of credit under the $1 billion facility.

Notes Payable to Affiliates

Our notes payable to unconsolidated affiliates as of June 30, 2002, were $555 million versus $872 million as of December 31, 2001. The decrease is primarily due to the partial repayment of Gemstone debt securities.

Securities of Subsidiaries and Minority Interests

Total amounts outstanding for securities of subsidiaries and minority interests were $4,154 million at June 30, 2002, versus $4,013 million at December 31, 2001. The increase was due to the consolidation of our Eagle Point Cogeneration Partnership and our Capitol District Energy Center Cogeneration Associates investments in January 2002.

In July 2002, we purchased from unaffiliated investors 200,000 shares of preferred stock in Coastal Oil & Gas Resources, Inc. and Coastal Limited Ventures, Inc., our wholly owned subsidiaries, for $65 million plus accrued and unpaid dividends. We purchased the limited partnership interest, from an unaffiliated investor, in 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.

Lines of Credit

Mesquite, a subsidiary of Chaparral and our affiliate, may borrow up to $925 million from us under a line of credit facility. As of June 30, 2002, Mesquite had $788 million outstanding under this facility at an interest rate of 2.3%.

Letters of Credit

As of June 30, 2002, we had outstanding letters of credit of $1,010 million 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, we 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 under the five time-charter agreements is approximately $2.5 billion over the term of the time charters. 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.

Commitments and Contingencies

See Item 1, Financial Statements, Note 12, which is incorporated herein by reference.

New Accounting Pronouncements Not Yet Adopted

See Item 1, Financial Statements, Note 17, which is incorporated herein by reference.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

We have made statements in this document that constitute forward-looking statements, as that term is defined in the Private Securities Litigation Reform Act of 1995. These statements are subject to risks and uncertainties. Forward-looking statements include information concerning possible or assumed future results of operations. These statements may relate to information or assumptions about:

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

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

Item 3. Quantitative and Qualitative Disclosures About Market Risk

There are no material changes in our quantitative and qualitative disclosures about market risks from those reported in our Annual Report on Form 10-K for the year ended December 31, 2001, except as presented below:

Commodity Price Risk

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

	June 30, 2002	December 31, 2001
	(In millions)	
Trading Value-at-Risk	$12	$18
Non-Trading Value-at-Risk	$ 5	$15
Portfolio Value-at-Risk	$ 9	$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.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Financial Statements, Note 12, 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 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 six remaining *Carlsbad* lawsuits are as follows: one filed in district court in Harris County, Texas (*Geneva Smith, et al v. EPEC and EPNG*, filed October 23, 2000), and five filed in state district court in Carlsbad, New Mexico (*Chapman, as Personal Representative of the Estate of Amy Smith Heady, v. EPEC, EPNG and John Cole*, filed February 9, 2001; *Chapman, as Personal Representative of the Estate of Dustin Wayne Smith, v. EPEC, EPNG and John Cole; Chapman, as Personal Representative of the Estate of Terry Wayne Smith, v. EPNG, EPEC and John Cole; Rackley, as Personal Representative of the Estate of Glenda Gail Sumler, v. EPEC, EPNG and John Cole*; and *Rackley, as Personal Representative of the Estate of Amanda Sumler Smith, v. EPEC, EPNG, and John Cole*, all filed March 16, 2001). We have reached a contingent settlement in an additional case (*Dawson, as Personal Representative of Kirsten Janay Sumler, v. EPEC and EPNG*, filed November 8, 2000).

The purported shareholder class actions filed in the U.S. District Court for the Southern District of Texas, Houston Division, are: *Goldfarb v. El Paso Corporation, William Wise, Rodney D. Erskine, and H. Brent Austin*, filed July 18, 2002; *Residuary Estate Mollie Nussbacher, Adele Brody Life Tenant v. El Paso Corporation, William Wise, and H. Brent Austin*, filed July 25, 2002; *Johnson v. El Paso Corporation, William Wise, and H. Brent Austin*, filed July 29, 2002; *Wilson v. El Paso Corporation, William Wise, Rodney D. Erskine, and H. Brent Austin*, filed August 1, 2002; and *Sandra Jean Malin Revokable Trust v. El Paso Corporation, William Wise, Rodney D. Erskine, and H. Brent Austin*, filed August 1, 2002.

Item 2. Changes in Securities and Use of Proceeds

On July 7, 2002, El Paso's Amended and Restated Shareholder Rights Agreement dated as of January 20, 1999 expired. We sent notice to the New York Stock Exchange and Pacific Exchange to deregister the rights under the Exchange Act.

Item 3. Defaults Upon Senior Securities

None.

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

We held our annual meeting of stockholders on May 20, 2002. Proposals we presented for a stockholders' vote included the election of eleven directors, the adoption of an amended employee stock purchase plan, an amendment to the certificate of incorporation, ratification of appointment of PricewaterhouseCoopers LLP as independent certified public accountants for the fiscal year 2002 and two stockholder proposals.

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

	For	Withheld
Byron Allumbaugh	454,292,797	12,891,285
John M. Bissell	454,326,019	12,858,063
Juan Carlos Braniff	458,392,938	8,791,144
James F. Gibbons	454,570,529	12,613,553
Anthony W. Hall, Jr.	461,157,072	6,027,010
Ronald L. Kuehn, Jr.	458,105,930	9,078,152
J. Carleton MacNeil, Jr.	458,268,258	8,915,824
Thomas R. McDade	458,112,825	9,071,257
Malcolm Wallop	458,024,004	9,160,078
William A. Wise	459,758,724	7,425,358
Joe B. Wyatt	454,111,664	12,772,419

There were no broker non-votes for the election of directors.

Two management proposals were presented for a stockholder vote. One proposal was to approve an amendment and restatement of El Paso's Employee Stock Purchase Plan to increase the number of shares authorized for issuance, and the second proposal was to approve an amendment to El Paso's Restated Certificate of Incorporation to increase the number of shares authorized. The proposals were approved with the following voting results:

	For	Against	Abstain
Amendment and Restatement of the El Paso Corporation Employee Stock Purchase Plan	453,566,179	10,562,104	3,055,799
Amendment to the El Paso Corporation Restated Certificate of Incorporation	429,684,937	34,461,180	3,037,965

There were no broker non-votes on the proposals.

The appointment of PricewaterhouseCoopers LLP as the Company's independent certified public accountants for the fiscal year 2002 was ratified with the following voting results:

	For	Against	Abstain
Ratification of PricewaterhouseCoopers LLP as Independent Certified Public Accountants for 2002	446,512,252	18,470,411	2,201,419

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

Two proposals submitted by stockholders were presented for a stockholder vote. One proposal called for stockholder approval for the cancellation of the restricted stock grant program, and the second proposal called for stockholder approval regarding the shareholder approval of any adoption of poison pills. The first stockholder proposal was not approved and the second stockholder proposal was approved with the following voting results:

	For	Against	Abstain
Stockholder Proposal regarding Cancellation of the Restricted Stock Grant Program	37,006,761	368,011,515	6,103,254
Stockholder Proposal regarding Shareholder Approval of Any Adoption of Poison Pills	259,004,031	147,189,453	4,888,048

There were 56,062,552 broker non-votes on the stockholder proposal regarding cancellation of the restricted stock grant program and 56,102,549 broker non-votes on the stockholder proposal regarding shareholder approval of any adoption of poison pills.

Item 5. Other Information

None.

Item 6. Exhibits and Reports on Form 8-K

a. Exhibits

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

Exhibit Number	Description
3.A	— Restated Certificate of Incorporation of El Paso, as filed with the Delaware Secretary of State on February 7, 2001, as amended on May 23, 2002 (Exhibit 3.A to our Registration Statement on Form 8-A filed June 19, 2002).
4.B	— Certificate of Elimination and Retirement of Series B Mandatorily Convertible Single Reset Preferred Stock and Series C Mandatorily Convertible Single Reset Preferred Stock of El Paso as filed with the Delaware Secretary of State on May 23, 2002 (Exhibit 4.B to our Registration Statement on Form 8-A filed June 19, 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 filed May 10, 1999).
4.D.1	Seventh Supplemental Indenture dated as of June 10, 2002, by and between El Paso and JPMorgan Chase Bank (formerly The Chase Manhattan Bank) as Trustee. (Exhibit 4.2 to our Registration Statement on Form S-4 filed July 17, 2002, File No. 333-96621); Eighth Supplemental Indenture between El Paso and JPMorgan Chase Bank dated June 26, 2002 (Exhibit 4.A to our Form 8-K filed June 26, 2002).
4.E	— Purchase Contract Agreement dated June 26, 2002 between El Paso and JPMorgan Chase Bank, as Purchase Contract Agent (Exhibit 4.B to our Form 8-K filed June 26, 2002).
4.F	— Pledge Agreement dated June 26, 2002 among El Paso, The Bank of New York, as Collateral Agent, Securities Intermediary and Custodial Agent, and JPMorgan Chase Bank, as Purchase Control Agent (Exhibit 4.C to our Form 8-K filed June 26, 2002).

Exhibit Number		Description
4.G	—	Remarketing Agreement dated June 26, 2002 among El Paso, JPMorgan Chase Bank, as Purchase Contract Agent, and Credit Suisse First Boston Corporation, as Remarketing Agent (Exhibit 4.D to our Form 8-K filed June 26, 2002).
*10.A	—	$3,000,000,000 364-Day Revolving Credit and Competitive Advance Facility Agreement dated May 15, 2002, by and among El Paso, EPNG, TGP, the several banks and other financial institutions from time to time parties thereto, and JPMorgan Chase Bank, as Administrative Agent and CAF Advance Agent, ABN Amro Bank N.V. and Citibank, N.A., as Co-Documentation Agents, and Bank of America, N.A. and Credit Suisse First Boston, as Co-Syndication Agents.
*10.B	—	Amended and Restated $1,000,000,000 3-Year Revolving Credit and Competitive Advance Facility Agreement dated June 27, 2002 by and among El Paso, EPNG, TGP, El Paso CGP, the several banks and other financial institutions from time to time parties thereto, and JPMorgan Chase Bank, as Administrative Agent, CAF Advance Agent and Issuing Bank, Citibank, N.A. and ABN Amro Bank N.V., as Co-Documentation Agents, and Bank of America, N.A., as Syndication Agent.
*+10.J.1	—	Amendment No. 3 to the El Paso Corporation 2001 Omnibus Incentive Compensation Plan effective July 17, 2002.
*+10.M	—	Deferred Compensation Plan Amended and Restated effective as of June 13, 2002.
+10.R	—	Employee Stock Purchase Plan Amended and Restated as of January 29, 2002 (Exhibit 10.1 to our Registration Statement on Form S-8 filed July 23, 2002, File No. 333-96959).
*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
May 31, 2002	Announced the key elements of our strategic repositioning plan.
June 14, 2002	Reported the Computation of the Ratio of Earnings to Fixed Charges for the five years ended December 31, 2001, and for the three months ended March 31, 2001 and 2002.
June 14, 2002	Announced the sale of San Juan Basin assets to El Paso Energy Partners.
June 17, 2002	Filed exhibits in connection with the sale of shares of our common stock and our equity security units.
June 19, 2002	Filed exhibits in connection with the sale of shares of our common stock and our equity security units.
June 26, 2002	Filed exhibits in connection with the sale of our shares of our common stock and our equity security units.

Date	Event Reported
July 12, 2002	Filed a press release announcing the receipt of a subpoena for documents.
July 22, 2002	Announced the completion of the removal the rating trigger on the Clydesdale agreements.

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 May 30, June 17, July 10, July 12, July 23, July 25, and August 8, 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: August 13, 2002

/s/ H. BRENT AUSTIN

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

Date: August 13, 2002

/s/ JEFFREY I. BEASON

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