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 1-7176

El Paso CGP Company

(Exact Name of Registrant as Specified in its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	**74-1734212** (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**

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 $1 per share. Shares outstanding on August 14, 2002: 1,000

EL PASO CGP COMPANY MEETS THE CONDITIONS OF GENERAL INSTRUCTION H(1)(a) AND (b) OF FORM 10-Q AND IS THEREFORE FILING THIS REPORT WITH A REDUCED DISCLOSURE FORMAT AS PERMITTED BY SUCH INSTRUCTION.

PART I — FINANCIAL INFORMATION

Item 1. Financial Statements

EL PASO CGP COMPANY

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

	Quarter Ended June 30,		Six Months Ended June 30,	
	2002	2001	2002	2001
Operating revenues	$1,950	$2,655	$ 4,505	$ 5,211
Operating expenses				
Cost of products and services	1,182	1,676	2,458	3,173
Operation and maintenance	332	540	661	916
Merger-related costs and asset impairments	—	217	—	982
Ceiling test charges	233	—	243	—
Depreciation, depletion and amortization	166	185	363	342
Taxes, other than income taxes	17	51	52	112
	1,930	2,669	3,777	5,525
Operating income (loss)	20	(14)	728	(314)
Other income (expense)				
Earnings from unconsolidated affiliates	33	44	84	105
Other, net	21	28	(4)	39
	54	72	80	144
Income (loss) before interest, income taxes and other charges	74	58	808	(170)
Non-affiliated interest and debt expense	113	112	220	236
Affiliated interest expense, net	2	18	5	22
Minority interest	11	12	21	26
Income taxes	(17)	(19)	184	(51)
	109	123	430	233
Income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	(35)	(65)	378	(403)
Discontinued operations, net of income taxes	(67)	(3)	(86)	(2)
Extraordinary items, net of income taxes	—	3	—	(7)
Cumulative effect of accounting changes, net of income taxes	14	—	14	—
Net income (loss)	$ (88)	$ (65)	$ 306	$ (412)

See accompanying notes.

EL PASO CGP COMPANY

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

	June 30, 2002	December 31, 2001
ASSETS		
Current assets		
Cash and cash equivalents	$ 164	$ 141
Accounts and notes receivable, net		
Customer	1,562	1,786
Affiliates	507	546
Other	218	188
Inventory	737	683
Assets from price risk management activities	239	425
Other	778	418
Total current assets	4,205	4,187
Property, plant and equipment, at cost		
Natural gas and oil properties, at full cost	7,057	7,765
Pipelines	6,617	6,541
Refining, crude oil and chemical facilities	2,383	2,425
Power facilities	473	288
Gathering and processing systems	387	428
Other	57	60
	16,974	17,507
Less accumulated depreciation, depletion and amortization	5,945	5,790
Total property, plant and equipment, net	11,029	11,717
Other assets		
Investments in unconsolidated affiliates	1,800	1,882
Assets from price risk management activities	1,022	267
Other	698	1,013
	3,520	3,162
Total assets	$18,754	$19,066

See accompanying notes.

EL PASO CGP COMPANY

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

	June 30, 2002	December 31, 2001
LIABILITIES AND STOCKHOLDER'S EQUITY		
Current liabilities		
Accounts and notes payable		
Trade	$ 1,726	$ 1,832
Affiliates	1,771	1,336
Other	392	359
Short-term borrowings (including current maturities of long-term debt and other financing obligations)	552	1,410
Liabilities from price risk management activities	113	213
Income taxes payable	440	198
Other	486	432
Total current liabilities	5,480	5,780
Long-term debt and other financing obligations, less current maturities	5,089	5,107
Other liabilities		
Liabilities from price risk management activities	174	1
Deferred income taxes	1,596	1,671
Other	364	643
	2,134	2,315
Commitments and contingencies		
Securities of subsidiaries		
Company-obligated preferred securities of consolidated trusts	300	300
Minority interests	768	594
	1,068	894
Stockholder's equity		
Common stock, par value $1 per share; authorized and issued 1,000 shares	—	—
Additional paid-in capital	1,305	1,305
Retained earnings	3,691	3,385
Accumulated other comprehensive income (loss)	(13)	280
Total stockholder's equity	4,983	4,970
Total liabilities and stockholder's equity	$18,754	$19,066

See accompanying notes.

EL PASO CGP COMPANY

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

	Six Months Ended June 30, 2002	2001
Cash flows from operating activities		
Net income (loss)	$ 306	$(412)
Less loss from discontinued operations, net of income taxes	(86)	(2)
Net income (loss) before discontinued operations	392	(410)
Adjustments to reconcile net income (loss) to net cash from operating activities		
Non-cash gains from power and trading activities	(481)	—
Non-cash portion of merger-related costs, asset impairments and changes in estimates	—	1,059
Depreciation, depletion and amortization	363	342
Ceiling test charges	243	—
Undistributed earnings of unconsolidated affiliates	(21)	(57)
Net gain on the sale of assets	(24)	(2)
Deferred income tax expense (benefit)	(47)	30
Extraordinary items	—	6
Cumulative effect of accounting change	(23)	—
Other non-cash income items	9	(2)
Working capital changes	238	(408)
Non-working capital changes and other	(100)	(124)
Cash provided by continuing operations	549	434
Cash provided by (used in) discontinued operations	48	(9)
Net cash provided by operating activities	597	425
Cash flows from investing activities		
Additions to property, plant and equipment	(750)	(944)
Net proceeds from the sale of assets	837	199
Additions to investments	(121)	(188)
Net proceeds from investments	2	128
Cash deposited in escrow	(85)	—
Repayment of notes receivable from unconsolidated affiliates	98	158
Other	45	2
Cash provided by (used in) continuing operations	26	(645)
Cash used in investing activities by discontinued operations	(7)	(26)
Net cash provided by (used in) investing activities	19	(671)
Cash flows from financing activities		
Net repayments under commercial paper and short-term credit facilities	(30)	(795)
Issuances of common stock	—	2
Net proceeds from the issuance of long-term debt and other financing obligations	90	197
Payments to retire long-term debt and other financing obligations	(1,103)	(493)
Payments to minority interests	(54)	—
Dividends paid	—	(13)
Increase (decrease) in notes payable to unconsolidated affiliates	(55)	4
Net change in affiliated advances payable	569	1,472
Contributions from (distributions to) discontinued operations	31	(26)
Cash provided by (used in) continuing operations	(552)	348
Cash provided by (used in) financing activities by discontinued operations	(31)	26
Net cash provided by (used in) financing activities	(583)	374
Increase in cash and cash equivalents	33	128
Less increase (decrease) in cash and cash equivalents related to discontinued operations	10	(9)
Increase in cash and cash equivalents from continuing operations	23	137
Cash and cash equivalents		
Beginning of period	141	57
End of period	$ 164	$ 194

See accompanying notes.

EL PASO CGP COMPANY

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

	Quarter Ended June 30,		Six Months Ended June 30,	
	2002	2001	2002	2001
Net income (loss)	$ (88)	$(65)	$ 306	$(412)
Foreign currency translation adjustments	23	8	23	2
Unrealized net gains (losses) from cash flow hedging activity				
Cumulative-effect transition adjustment (net of tax of $248)	—	—	—	(459)
Unrealized mark-to-market gains (losses) arising during period (net of tax of $43 and $113 in 2002 and $219 and $281 in 2001)	(77)	410	(195)	520
Reclassification adjustments for changes in initial value to settlement date (net of tax of $18 and $65 in 2002 and $65 and $266 in 2001)	(37)	26	(121)	206
Other comprehensive gain (loss)	(91)	444	(293)	269
Comprehensive income (loss)	$(179)	$379	$ 13	$(143)

See accompanying notes.

EL PASO CGP COMPANY

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Basis of Presentation

We prepared this Quarterly Report on Form 10-Q under the rules and regulations of the United States Securities and Exchange Commission. Because this is an interim period filing presented using a condensed format, it does not include all of the disclosures required by generally accepted accounting principles. You should read it along with our 2001 Annual Report on Form 10-K which includes a summary of our significant accounting policies and other disclosures. The financial statements as of 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, 6 and 7), 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 stockholder's 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. 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. 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 would have been approximately $3 million and $6 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)	
Loss from continuing operations before extraordinary items and cumulative effect of accounting changes	$ (62)	$ (397)
Net loss	$ (62)	$ (406)

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 fuel supply contracts 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 stockholder's equity. Revenues and costs that have been netted as a result of adopting this consensus was as follows:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2002	2001	2002	2001
	(In millions)			
Gross operating revenues	$ 6,688	$ 5,905	$11,573	$13,629
Costs reclassified	(4,738)	(3,250)	(7,068)	(8,418)
Net operating revenues reported in the income statements	$ 1,950	$ 2,655	$ 4,505	$ 5,211

The EITF continues to evaluate disclosure and valuation issues in its continuing 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 completed the Eagle Point Cogeneration restructuring in the first quarter of 2002. The restructured power contract is presented in our balance sheet as an asset from price risk management activities, and the associated power supply agreement is presented as a liability from price risk management activities. In our income statement we present, as revenues, the original adjustment that occurs when the contracts are marked to fair value as derivatives, as well as subsequent changes in the value of the contracts. Other 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. We 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 recorded this payment as revenue. During the first six months of 2002, we recognized revenues from power restructuring and contract termination activities of $973 million and corresponding costs of $551 million, most of which occurred during the first quarter.

2. Divestitures

In December 2001, El Paso Corporation (El Paso), our parent, announced a plan to strengthen its balance sheet in order to improve the its 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 February 2002, we sold CIG Trailblazer Gas Company, L.L.C., a company which owned pipeline expansion rights, to a third party. Proceeds from the sale were $12 million, and we recorded a gain on the sale of approximately $11 million, $7 million after taxes.

In March 2002, we sold natural gas and oil properties to El Paso and to third parties. Net proceeds from these sales 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 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.

Our parent also announced the sales of an additional $133 million of assets, which include natural gas and oil production properties and related contracts and a natural gas gathering system. In July 2002, we completed the sale of the natural gas and oil production properties and related contracts. 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 July 2002, our parent entered into a letter of intent with El Paso Energy Partners, L.P., an affiliate, to sell our Typhoon offshore natural gas and oil gathering pipelines, as well as natural gas liquids (NGL) pipelines and a related fractionation facility in Texas. The Typhoon pipelines consist of a 35-mile, 20-inch natural gas pipeline and a 16-mile, 12-inch oil pipeline from the Typhoon platform in the Green Canyon area of the Gulf of Mexico. We stopped depreciating these assets beginning in July 2002 since these assets are held for sale.

3. Merger-Related and Asset Impairments

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

	Quarter Ended June 30, 2001	Six Months Ended June 30, 2001
	(In millions)	
Merger-related costs	$208	$973
Asset impairments	9	9
Total	$217	$982

Merger-Related Costs

On January 29, 2001, we merged with El Paso in a transaction 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	$ 7	$583
Transaction costs	—	7
Business and operational integration costs	141	155
Merger-related asset impairments	19	153
Other	41	75
	$208	$973

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 merger, El Paso completed an employee restructuring across all of our operating segments, reducing approximately 3,200 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 responsibility 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 $87 million. The pension and post-retirement benefits were accrued on 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 El Paso common stock incurred on the merger date in exchange for the fair value of our 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 the merger. These charges occurred in our Merchant Energy, Pipeline, 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 El Paso and other miscellaneous charges. These items were expensed as incurred.

Asset Impairments

During the quarter ended June 30, 2001, we incurred an asset impairment charge of approximately $9 million resulting from the unrecoverability of capitalized costs of Merchant Energy's Corpus Christi refinery.

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 El Paso and our combined operating strategy. These changes in estimates reduced our after-tax earnings by approximately $135 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 $243 million, of which $10 million was charged during the first quarter and $233 million during the second quarter. The write-down includes $226 million for our Canadian full cost pool, $10 million for our Brazilian full cost pool and $7 million for 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 for our international cost pools would not have materially changed since we do not significantly hedge our international production activities. However, we would have incurred an additional charge of $28 million related to our United States full cost pool.

6. Discontinued Operations

In June 2002, our parent's Board of Directors authorized the sale of our coal mining operations. Those 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 authorization of the sale by our parent's 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 because 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 El Paso, we sold 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 $40 million and $184 million, and we recognized an extraordinary net gain (loss) of approximately $3 million and $(7) million, net of income tax expense of approximately $2 million and $1 million.

8. Financial Instruments and Price Risk Management Activities

The following table summarizes the carrying value of our trading and non-trading price risk management assets and liabilities as of June 30, 2002 and December 31, 2001:

	June 30, 2002	December 31, 2001
	(In millions)	
Net assets (liabilities)		
Trading contracts[1][3]	$ (3)	$(23)
Non-trading contracts[2][3]		
Derivatives designated as hedges	(2)	501
Other derivatives	979	—
Total price risk management activities	$974	$478

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

Other derivatives are 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 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 $15 million in May 2002. This amount, net of income taxes of $5 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 $10 million in accumulated other comprehensive income, we estimate that unrealized gains of $29 million, net of income taxes, related to these derivatives will be reclassified to income over the next twelve months.

9. Inventory

Our inventory consisted of the following:

	June 30, 2002	December 31, 2001
	(In millions)	
Refined products, crude oil and chemicals	$635	$576
Materials and supplies and other	102	107
	$737	$683

10. Debt and Other Credit Facilities

At December 31, 2001, our weighted average interest rate on our short-term credit facilities was 2.4%, and there were no amounts outstanding under these facilities at June 30, 2002. We had the following short-term borrowings and other financing obligations:

	June 30, 2002	December 31, 2001
	(In millions)	
Current maturities of long-term debt and other financing obligations	$549	$1,310
Short-term credit facility	—	30
Notes payable to unconsolidated affiliates	—	67
Other	3	3
	$552	$1,410

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

Issuances

Date	Company	Type	Interest Rate	Principal	Net Proceeds	Due Date
				(In millions)		
2002						
April	Mohawk River Funding IV[(1)]	Senior secured notes	7.75%	$ 92	$ 90	2008
July	Utility Contract Funding[(1)]	Senior secured notes	7.944%	829	822	2016

(1) These notes are collateralized solely by the cash flows and contracts of these consolidated subsidiaries, and are non-recourse to our parent and other affiliated 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.

Retirements

Date	Company	Type	Interest Rate	Principal	Net Payments	Due Date
				(In millions)		
2002						
March	El Paso CGP	Long-term debt	Variable	$400	$400	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	Coastal Oil & Gas	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	22	22	2002
July	El Paso CGP	Long-term debt	Variable	55	55	2002
July-Aug.	El Paso CGP	Long-term debt	Variable	44	44	2010-2028

In June 2002, El Paso amended its existing $1 billion 3-year revolving credit and competitive advance facility to permit El Paso to issue up to $500 million in letters of credit and to adjust pricing terms. This facility matures in August 2003. We are a designated borrower under this facility and, as such, are liable for any amounts outstanding under this facility. The interest rate varies based on El Paso's 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 $450 million in letters of credit were issued under the facility.

In August 2002, holders of our $460 million 6.625% FELINE PRIDES℠ will be required to purchase El Paso common stock. The holder may either exchange the FELINE PRIDES℠ for 0.6622 shares of El Paso common stock, or continue to hold the FELINE PRIDES℠ and pay cash for the stock. For each FELINE PRIDES℠ exchanged, we will reduce the outstanding principal amount of our FELINE PRIDES℠.

Other Financing Arrangements

During 2000, El Paso formed a series of companies to provide financing to invest in various El Paso capital projects and other assets. Several of our assets, including our Colorado Interstate Gas transmission system and, beginning in July 2002, additional natural gas and oil properties as collateral to El Paso's financings.

11. Commitments and Contingencies

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 of approximately $44 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 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 $279 million for expected remediation costs (including related environmental litigation), which included $15 million reserved for our discontinued coal mining operations. In addition, we expect to make capital expenditures for environmental matters of approximately

$199 million in the aggregate for the years 2002 through 2007. These expenditures primarily relate to compliance with clean air regulations.

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.

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 17 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 $5 million and $8 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 March 2001, Colorado Interstate Gas Company (CIG) filed a rate case with the Federal Energy Regulatory Commission (FERC) proposing increased rates of $9 million annually and new and enhanced services for its customers. This filing was required under the settlement of its 1996 general rate case. CIG received an order from the FERC in late April 2001, which suspended the rates until October 1, 2001, subject to refund, and subject to the outcome of an evidentiary hearing. On September 26, 2001, the FERC issued an order rejecting two firm services CIG had proposed in its rate filing and required it to reallocate the costs allocated to those two services to existing services. CIG has complied with this order and has arranged with the affected customers to provide service under existing rate schedules. CIG and its customers entered into a unanimous settlement agreement in May 2002 settling all issues in the case. The settlement, which contained a modest rate increase, was approved by the FERC in July 2002. Provided that no parties seek rehearing within 30 days, this will become a final order. We will pay refunds plus accrued interest within 60 days from the final order date. We have made provisions for these refunds and, as a result, the refunds will not have an adverse effect on our financial position or results of operations.

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 El Paso pipelines 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 rates 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.

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 Matters

Affiliates of Enron hold both short-term and long-term capacity on our pipeline systems. At this time, we are uncertain as to Enron's intent to maintain or release capacity associated with contracts on our 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 us. Future revenue related to these capacity contracts will depend upon the outcome of Enron's bankruptcy proceedings and our 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.

12. 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 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	$211	$109	$1,527 [2]	$103	$ —	$1,950
Intersegment revenues	13	221	(222) [2]	10	(22)	—
Ceiling test charges	—	233	—	—	—	233
Operating income (loss)	85	(76)	6	18	(13)	20
EBIT	114	(78)	26	27	(15)	74

	Quarter Ended June 30, 2001					
	Pipelines	Production	Merchant Energy	Field Services	Corporate & Other[1]	Total
	(In millions)					
Revenues from external customers	$231	$574	$1,419[2]	$314	$ 117	$2,655
Intersegment revenue	21	(99)	78[2]	14	(14)	—
Merger-related costs and asset impairments	132	—	19	4	62	217
Operating income (loss)	(54)	261	(74)	18	(165)	(14)
EBIT	(29)	264	(39)	19	(157)	58

	Six Months Ended June 30, 2002					
	Pipelines	Production	Merchant Energy	Field Services	Corporate & Other[1]	Total
	(In millions)					
Revenues from external customers	$467	$235	$3,610 [2]	$193	$ —	$4,505
Intersegment revenues	20	484	(486) [2]	21	(39)	—
Ceiling test charges	—	243	—	—	—	243
Operating income (loss)	217	82	433	22	(26)	728
EBIT	292	82	429	32	(27)	808

	Six Months Ended June 30, 2001					
	Pipelines	Production	Merchant Energy	Field Services	Corporate & Other[1]	Total
	(In millions)					
Revenues from external customers	$542	$1,015	$2,794[2]	$566	$ 294	$5,211
Intersegment revenues	34	(111)	247[2]	45	(215)	—
Merger-related costs and asset impairments	211	61	153	5	552	982
Operating income (loss)	6	411	(95)	42	(678)	(314)
EBIT	61	411	(13)	43	(672)	(170)

(1) Includes our Corporate, 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	$ 74	$ 58	$ 808	$(170)
Non-affiliated interest and debt expense	(113)	(112)	(220)	(236)
Affiliated interest expense, net	(2)	(18)	(5)	(22)
Minority interest	(11)	(12)	(21)	(26)
Income taxes	17	19	(184)	51
Income (loss) from continuing operations before extraordinary items and cumulative effect of accounting changes	$ (35)	$ (65)	$ 378	$(403)

	June 30, 2002	December 31, 2001
	(In millions)	
Pipelines	$ 5,324	$ 5,481
Production	5,195	6,534
Merchant Energy	6,933	5,888
Field Services	558	546
Corporate and other	509	229
Total segment assets	18,519	18,678
Discontinued operations	235	388
Total consolidated assets	$18,754	$ 19,066

13. Investments in Unconsolidated Affiliates and Related Party Transactions

We hold investments in various affiliates which we account for using the equity method of accounting. Summarized financial information for 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 $8 for the quarters ended and $18 million and $24 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	$311	$662	$540	$892
Operating expenses	233	579	405	732
Income from continuing operations	27	37	72	92
Net income	27	37	72	92

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.

Related Party Transactions

In March 2002, we acquired assets with a net book value, net of deferred taxes, of approximately $8 million from El Paso.

Additionally, we sold natural gas and oil properties to El Paso. Net proceeds from these sales were $404 million, and we did not recognize a gain or loss on the properties sold.

We participate in El Paso's cash management program which matches short-term cash surpluses and needs of its participating affiliates, thus minimizing total borrowing from outside sources. We had net borrowings of $1,479 million, at a market rate of interest which was 1.9% at June 30, 2002 and $908 million at a market interest rate of 2.1% at December 31, 2001. In addition, we had a demand note receivable with El Paso of $122 million at June 30, 2002, with an interest rate of 2.4%, and $120 million at December 31, 2001, with an interest rate of 4.2%.

At June 30, 2002, we had current accounts and notes receivable from related parties of $385 million and $426 million at December 31, 2001. In addition, we had a non-current note receivable from a related party of $26 million and $27 million included in other non-current assets at June 30, 2002 and at December 31, 2001.

At June 30, 2002, we had accounts and notes payable to related parties of $292 million and $428 million at December 31, 2001. In addition, included in short-term borrowings at December 31, 2001 was a current note payable to related parties of $67 million.

El Paso Energy Partners

Our parent has entered into a letter of intent to sell our Typhoon offshore natural gas and oil pipelines as well as our NGL pipelines and a related fractionation facility in Texas to El Paso Energy Partners. This proposed transaction has been approved by both our parent's and El Paso Energy Partners' Boards of Directors which included the approval by El Paso Energy Partners' special conflicts committee. There were also fairness opinions issued on this transaction. This transaction is subject to customary regulatory review and approval. The closing of the sale is anticipated by the end of 2002.

14. Minority Interests

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 interests 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 limited partner's outstanding capital plus unpaid priority returns.

15. 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 28, 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

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.

Results of Operations

Our results of operations, along with the impact by segment of the merger-related costs, asset impairments and other charges, are presented below. 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(2)	Pro-forma	Reported	Charges(2)	Pro-forma
Pipelines	$ 114	$ —	$ 114	$ (29)	$ 152	$ 123
Production	(78)	233	155	264	7	271
Merchant Energy	26	—	26	(39)	91	52
Field Services	27	(10)	17	19	5	24
Segment EBIT	89	223	312	215	255	470
Corporate and other	(15)	—	(15)	(157)	165	8
Consolidated EBIT	74	223	297	58	420	478
Non-affiliated interest and debt expense	(113)	—	(113)	(112)	—	(112)
Affiliated interest expense, net	(2)	—	(2)	(18)	—	(18)
Minority interest	(11)	—	(11)	(12)	—	(12)
Income taxes	17	(77)	(60)	19	(90)	(71)
Discontinued operations, net of taxes	(67)	67	—	(3)	3	—
Extraordinary items, net of taxes	—	—	—	3	(3)	—
Accounting changes, net of taxes	14	(14)	—	—	—	—
Net income (loss)	$ (88)	$199	$ 111	$ (65)	$ 330	$ 265

(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	= million tons
MBbls	= thousand barrels	MMWh	= thousand megawatt hours

When we refer to natural gas and oil in "equivalents," we are doing so to compare quantities of oil with quantities of natural gas or to express these different commodities in a common unit. In calculating equivalents, we use a generally recognized standard in which one Bbl 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.

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

	Six Months Ended June 30,					
	2002			2001		
	Reported	Charges[(1)]	Pro-forma	Reported	Charges[(1)]	Pro-forma
Pipelines	$ 292	$ —	$ 292	$ 61	$ 231	$ 292
Production	82	243	325	411	68	479
Merchant Energy	429	—	429	(13)	225	212
Field Services	32	(10)	22	43	6	49
Segment EBIT	835	233	1,068	502	530	1,032
Corporate and other	(27)	—	(27)	(672)	655	(17)
Consolidated EBIT	808	233	1,041	(170)	1,185	1,015
Non-affiliated interest and debt expense	(220)	—	(220)	(236)	—	(236)
Affiliated interest expense, net	(5)	—	(5)	(22)	—	(22)
Minority interest	(21)	—	(21)	(26)	—	(26)
Income taxes	(184)	(77)	(261)	51	(296)	(245)
Discontinued operations, net of taxes	(86)	86	—	(2)	2	—
Extraordinary items, net of taxes	—	—	—	(7)	7	—
Accounting changes, net of taxes	14	(14)	—	—	—	—
Net income (loss)	$ 306	$228	$ 534	$(412)	$ 898	$ 486

(1) Charges include merger-related costs, asset impairments, ceiling test charges, changes in accounting estimates, discontinued operations, extraordinary items, cumulative effect of accounting changes 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 12, 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	$114	$ (29)	$292	$ 61
Production	(78)	264	82	411
Merchant Energy	26	(39)	429	(13)
Field Services	27	19	32	43
Segment total	89	215	835	502
Corporate and other, net	(15)	(157)	(27)	(672)
Consolidated EBIT	$ 74	$ 58	$808	$(170)

Pipelines

Our Pipeline segment holds our interstate transmission business. 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 coal fired generators, as well as natural gas market price differentials which can effect our deliveries to our markets. Results can also be impacted by the ability to market excess natural gas which is influenced by a pipeline's rate of recovery 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	$ 224	$ 252	$ 487	$ 576
Operating expenses	(139)	(306)	(270)	(570)
Other income	29	25	75	55
EBIT	$ 114	$ (29)	$ 292	$ 61
Throughput volumes (BBtu/d)[1]	7,340	7,377	7,687	7,546

[1] Throughput volumes for 2001 exclude those related to pipeline systems sold in connection with FTC orders related to our merger with El Paso including 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 $28 million lower than the same period in 2001. The decrease was primarily due to the impact of lower prices on natural gas and liquids sales, including sales of natural gas produced, and resales of natural gas purchased from the Dakota gasification facility. Also contributing to the decrease were lower sales of excess natural gas, lower transportation revenues from capacity sold under short-term contracts due to milder weather in 2002 and lower 2002 sales of base gas from abandoned storage fields. Partially offsetting the decrease was higher reservation revenues from our system expansion projects, which were placed in service in 2001.

Operating expenses for the quarter ended June 30, 2002, were $167 million lower than the same period in 2001. The decrease was primarily due to merger-related costs of $132 million incurred to relocate our pipeline operations from Detroit, Michigan to Houston, Texas, costs for employee benefits, retention and transition charges and a change in accounting estimate of $20 million recorded in the second quarter of 2001 primarily for additional environmental remediation liabilities. Also contributing to the decrease were lower corporate overhead allocations and lower amortization due to the implementation of SFAS No. 142 in 2002. Additionally, lower prices on natural gas purchased from the Dakota gasification facility, lower fuel costs resulting from lower natural gas prices and lower benefit costs in 2002 contributed to the decrease. The decrease was partially offset by an increase in 2002 in our estimated liabilities to assess and remediate our environmental exposure due to an ongoing evaluation of our facilities.

Other income for the quarter ended June 30, 2002, was $4 million higher than the same period in 2001 primarily due to the resolution of uncertainties associated with the sales of our interests in the Empire State and Iroquois pipeline systems in 2001.

Six Months Ended 2002 Compared to Six Months Ended 2001

Operating revenues for the six months ended June 30, 2002, were $89 million lower than the same period in 2001. The decrease was primarily due to the impact of lower prices on natural gas and liquids sales, including sales of natural gas produced and resales of natural gas purchased from the Dakota gasification facility. Also contributing to the decrease were lower sales of excess natural gas, lower transportation revenues from capacity sold under short-term contracts due to milder weather in 2002 and lower 2002 sales of base gas from abandoned storage fields. Partially offsetting the decrease was higher reservation revenues from our system expansion projects, which were placed in service in 2001.

Operating expenses for the six months ended June 30, 2002, were $300 million lower than the same period in 2001. The decrease was primarily due to merger-related costs of $211 million incurred to relocate our pipeline operations from Detroit, Michigan to Houston, Texas, costs for employee benefits, severance, retention and transition charges and a change in accounting estimate of $20 million for additional environmental remediation liabilities in 2001. Also contributing to the decrease were lower fuel costs resulting from lower natural gas prices, lower prices on natural gas purchased from the Dakota gasification facility and lower amortization due to the implementation of SFAS No. 142 in 2002. Additionally, lower benefit costs, cost efficiencies following our merger with El Paso and lower corporate overhead allocations in 2002 contributed to the decrease. Partially offsetting the decrease was an increase in 2002 in our estimated liabilities to assess and remediate our environmental exposure due to an ongoing evaluation of our facilities.

Other income for the six months ended June 30, 2002, was $20 million higher than the same period in 2001. The increase was primarily due to a gain on the sale of pipeline expansion rights in February 2002, higher equity earnings on Great Lakes Gas Transmission in 2002 and the resolution of uncertainties associated with the sales of our interests in the Empire State and Iroquois pipeline systems in 2001.

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 parent's strategic repositioning plan announced 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		Six Months Ended	
	2002	2001	2002	2001
	(In millions, except volumes and prices)			
Natural gas	$ 279	$ 414	$ 626	$ 782
Oil, condensate, and liquids	47	54	86	110
Other	4	7	7	12
Total operating revenues	330	475	719	904
Transportation and net product costs	(12)	(10)	(25)	(36)
Total operating margin	318	465	694	868
Operating expenses	(394)	(204)	(612)	(457)
Other income (expense)	(2)	3	—	—
EBIT	$ (78)	$ 264	$ 82	$ 411

	Quarter Ended June 30,		Six Months Ended June 30,	
	2002	2001	2002	2001
	(In millions, except volumes and prices)			
Volumes and prices				
Natural gas				
Volumes (MMcf)	65,465	98,489	148,731	189,129
Average realized prices[1] ($/Mcf)	$ 4.11	4.14	$ 4.08	$ 4.08
Oil, condensate and liquids				
Volumes (MBbls)	1,993	2,232	4,687	4,146
Average realized prices[1] ($/Bbl)	$ 23.19	$ 23.07	$ 17.59	25.91

[1] Net of transportation costs.

Second Quarter 2002 Compared to Second Quarter 2001

For the quarter ended June 30, 2002, operating revenues were $145 million lower than the same period in 2001 due primarily to a decline in natural gas volumes in 2002 when compared to the same period of 2001.

Transportation and net product costs for the quarter ended June 30, 2002, were $2 million higher than the same period in 2001 primarily due to a higher percentage of gas volumes subject to transportation fees partially offset by costs incurred in 2001 to meet minimum payments on pipeline agreements.

Operating expenses for the quarter ended June 30, 2002, were $190 million higher than the same period in 2001 due to increased oilfield services costs and non-cash full cost ceiling test charges totaling $233 million incurred in 2002, primarily for our Canadian full cost pool. The charge for the Canadian full cost pool primarily 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 our 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 $185 million lower than the same period in 2001. The decrease was primarily due to a decline in natural gas volumes and 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 production 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 six months ended June 30, 2002, were $11 million lower than the same period in 2001 primarily due to costs incurred in 2001 to meet minimum payments on pipeline agreements partially offset by a higher percentage of gas volumes.

Operating expenses for the six months ended June 30, 2002, were $155 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, non-cash full cost ceiling test charges totaling $243 million incurred in 2002 for our Canadian full cost pool and other international properties primarily in Australia and higher corporate overhead allocations. Also contributing to the increase were increased oilfield services costs. Partially offsetting these increases were merger-related costs of $61 million incurred in 2001 due to our merger with El Paso in January 2001, write-downs in 2001 totaling $7 million of materials and supplies resulting from the ongoing evaluation of our operating standards and plans, and lower severance and other taxes in 2002.

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. As in the case of our Eagle Point Cogeneration restructuring transaction discussed in results of operations below, our restructuring of power plant facilities and related assets are consolidated in our financial statements.

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

Our domestic power plants 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 five restructuring transactions, including contract terminations, of varying financial significance, and we have additional facilities which we will consider for restructuring in the future.

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	$ 79	$ 236	$ 672	$ 551
Operating and other revenues	146	10	205	36
Operating expenses	(219)	(320)	(444)	(682)
Other income (expense)	20	35	(4)	82
EBIT	$ 26	$ (39)	$ 429	$ (13)
Volumes[(1)]				
Physical				
Natural gas (BBtue/d)	—	—	—	3,457
Power (MMWh)	34	48	119	157
Crude oil and refined products (MBbls)	202,726	162,502	363,265	330,447
Financial Settlements (BBtue/d)	6,909	65,931	36,107	76,025

(1) Volumes include those settled 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 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 a significant transaction related to our Nejapa power facility. 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.

For the quarter ended June 30, 2002, trading and refining gross margins were $157 million lower than the same period in 2001. Contributing to the overall decrease were lower refining margins resulting from the lease of our Corpus Christi refinery and related assets to Valero Energy Corporation 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. For the quarter ended June 30, 2002, operating and other revenues were $136 million higher than the same period in 2001. The increase resulted from revenue from domestic and international power facilities that were consolidated in the fourth quarter of 2001 and the first quarter of 2002 and $90 million of revenues from the termination of the Nejapa power contract.

Operating expenses for the quarter ended June 30, 2002, were $101 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 $91 million recorded in the second quarter of 2001 associated with combining operations with

The Coastal Corporation (Coastal), our former parent. 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.

Other income for the quarter ended June 30, 2002, was $15 million lower than the same period in 2001. The decrease was primarily the result of the minority owner's interest in the gain from the termination of the Nejapa power contract and a decrease in equity earnings from unconsolidated 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 and Nejapa power plants. The Eagle Point Cogeneration restructuring transaction was completed in March 2002.

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), an affiliated 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 for the purpose of reducing the cost of debt UCF would issue.

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 at a cost of $37 per MWh.

From an accounting standpoint, the actions taken to restructure the contract required us to mark the restructured power contract and the power supply contracts to their fair value under SFAS No. 133. As a result, we recorded non-cash revenue representing the estimated fair value of the derivative contracts of approximately $898 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 our 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 $348 million. Total operating cash flows from this transaction amounted to approximately $120 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.

For the six months ended June 30, 2002, trading and refining gross margins were $121 million higher than the same period in 2001. The increase resulted from income recorded in the first quarter of 2002 related to the Eagle Point Cogeneration power plant contract restructuring. Partially offsetting the increase 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 $169 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 and $90 million of revenues from the termination of the Nejapa power contract. Partially offsetting the increase was the transfer of power index swaps on our Fulton and Rensselaer power facilities to a subsidiary of El Paso in February 2001 and the sale of a power facility to a related party in 2001.

Operating expenses for the six months ended June 30, 2002, were $238 million lower than the same period in 2001. The decrease resulted from merger-related costs, changes in accounting estimates and asset impairments of $225 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. 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.

Other income for the six months ended June 30, 2002, was $86 million lower than the same period in 2001. The decrease was primarily the result of the minority owner's interest in the gain on the termination of the Nejapa power contract of $13 million, the minority owner's interest in the Eagle Point transaction of $49 million and 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 owner's 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

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	$ 33	$ 44	$ 56	$ 85
Operating expenses	(16)	(26)	(34)	(43)
Other income (loss)	10	1	10	1
EBIT	$ 27	$ 19	$ 32	$ 43
Volume and prices				
Gathering and treating				
Volumes (BBtu/d)	637	1,032	642	985
Prices ($/MMBtu)	$ 0.15	$ 0.13	$ 0.14	$ 0.13
Processing				
Volumes (inlet BBtu/d)	1,713	1,932	1,688	1,939
Prices ($/MMBtu)	$ 0.14	$ 0.16	$ 0.13	$ 0.15

Second Quarter 2002 Compared to Second Quarter 2001

Total gross margins for the quarter ended June 30, 2002, were $11 million lower than the same period in 2001. The decrease was primarily due to lower natural gas liquids prices in 2002, which unfavorably impacted our processing volumes and margins in the Rockies and south Louisiana regions. Also contributing to the decrease was the sale of our Dragon Trail processing plant in May 2002 and lower gathering and treating volumes in 2002 due to natural declines in production in our operation regions.

Operating expenses for the quarter ended June 30, 2002, were $10 million lower than the same period in 2001. The decrease was primarily due to $5 million of merger-related costs in 2001 due to our January 2001 merger with El Paso and lower operating expenses as a result of our cost-saving efforts in 2002.

Other income for the quarter ended June 30, 2002, was $9 million higher than the same period in 2001 primarily due to a gain of $10 million recognized on the sale of our Dragon Trail processing plant, partially offset by lower earnings from our Deepwater Holdings equity investment which was sold to El Paso Energy Partners in October 2001.

Six Months Ended 2002 Compared to Six Months Ended 2001

Total gross margins for the six months ended June 30, 2002, were $29 million lower than the same period in 2001. The decrease was primarily due to lower natural gas liquids prices in 2002, which unfavorably impacted our processing volumes and margins in the Rockies and south Louisiana regions. Also contributing to the decrease was the sale of our Dragon Trail processing plant in May 2002 and lower gathering and treating volumes in 2002 due to natural declines in production in our operation regions.

Operating expenses for the six months ended June 30, 2002, were $9 million lower than the same period in 2001. The decrease was primarily due to $6 million of merger-related costs in 2001 due to our January 2001 merger with El Paso and lower operating expenses as a result of our cost-saving efforts in 2002. These decreases were slightly offset by higher depreciation expense as a result of placing assets in service in mid-2001.

Other income for the six months ended June 30, 2002, was $9 million higher than the same period in 2001 primarily due to a gain of $10 million recognized on the sale of our Dragon Trail processing plant, partially offset by lower earnings from our Deepwater Holding equity investments which was sold to El Paso Energy Partners in October 2001.

Corporate and Other, net

Corporate and other expenses, which include general and administrative activities as well as other miscellaneous businesses, for the quarter and six months ended June 30, 2002, were $142 million and $645 million lower than the same periods in 2001. The decrease was primarily a result of $165 million and $653 million in merger-related charges for the quarter and six months ended June 30, 2001, in connection with our merger with El Paso, additional costs for the quarter and six months ended June 30, 2001 of $103 million related to increased estimates of environmental remediation in 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 merger with El Paso.

Interest and Debt Expense

Non-affiliated Interest and Debt Expense

Non-affiliated interest and debt expense for the six months ended June 30, 2002, was $16 million lower than the same period in 2001 primarily due to retirement of long-term debt in the first quarter of 2002 and short-term borrowings, consisting of commercial paper and short-term bank credit facilities, in the first quarter of 2001. This decrease was partially offset by interest from the issuance of long-term debt in October 2001.

Affiliated Interest Expense, Net

Affiliated interest expense, net for the quarter and six months ended June 30, 2002, was $15 million and $17 million lower than the same period in 2001 due to lower short-term interest rates on average advances from El Paso Corporation under our cash management program.

Minority Interest

Minority interest expense for the quarter and six months ended June 30, 2002, was $1 million and $5 million lower than the same period in 2001, primarily due to lower average interest rates.

Income Taxes

Income tax benefit for the quarter ended June 30, 2002, was $17 million, resulting in effective tax rate of 33 percent. Income tax expense for the six months ended June 30, 2002, was $184 million, resulting in effective tax rate of 33 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 $19 million and $51 million, resulting in effective tax rates of 23 percent and 11 percent. The six months ended June 30, 2001 benefit was net of $105 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 34 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; and
- foreign income taxed at foreign rates.

Commitments and Contingencies

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

New Accounting Pronouncements Not Yet Adopted

See Item 1, Financial Statements, Note 15, which is incorporated herein by reference.

CAUTIONARY STATEMENT FOR PURPOSES OF THE "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This report contains or incorporates by reference forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Where any forward-looking statement includes a statement of the assumptions or bases underlying the forward-looking statement, we caution that, while we believe these assumptions or bases to be reasonable and to be made in good faith, assumed facts or bases almost always vary from the actual results, and the differences between assumed facts or bases and actual results can be material, depending upon the circumstances. Where, in any forward-looking statement, we or our management express an expectation or belief as to future results, that expectation or belief is expressed in good faith and is believed to have a reasonable basis. We cannot assure you, however, that the statement of expectation or belief will result or be achieved or accomplished. The words "believe," "expect," "estimate," "anticipate" and similar expressions will generally identify forward-looking statements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

This information updates, and you should read it in conjunction with, information disclosed in Part II, Item 7A in our Annual Report on Form 10-K for the year ended December 31, 2001, in addition to the information presented in Items 1 and 2 of this Quarterly Report on Form 10-Q.

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

PART II — OTHER INFORMATION

Item 1. Legal Proceedings.

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

Item 2. Changes in Securities.

None.

Item 3. Defaults Upon Senior Securities.

None.

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

None.

Item 5. Other Information.

None.

Item 6. Exhibits and Reports on Form 8-K.

a. Exhibits.

Each exhibit identified below is filed as a part of this report. Exhibits not incorporated by reference to a prior filing are designated by an "*"; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated.

Exhibit Number	Description
*10.A	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.
*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

None.

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 CGP COMPANY

Date: August 14, 2002

/s/ H. BRENT AUSTIN

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

Date: August 14, 2002

/s/ JEFFREY I. BEASON

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