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

# Form 10-Q

(Mark One)

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

**For the quarterly period ended March 31, 2001**

**OR**

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

**For the transition period from to**

**Commission File Number 1-14365**

# El Paso Corporation

(Exact Name of Registrant as Specified in its Charter)

| | |
|---|---|
| **Delaware**<br>(State or Other Jurisdiction of Incorporation or Organization) | **76-0568816**<br>(I.R.S. Employer Identification No.) |
| **El Paso Building**<br>**1001 Louisiana Street**<br>**Houston, Texas**<br>(Address of Principal Executive Offices) | **77002**<br>(Zip Code) |

Registrant's Telephone Number, Including Area Code: **(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 $3.00 per share. Shares outstanding on May 4, 2001: 509,175,906

## PART I — FINANCIAL INFORMATION

**Item 1. Financial Statements**

## EL PASO CORPORATION

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

| | Quarter Ended March 31, 2001 | 2000 |
|---|---|---|
| Operating revenues | $17,754 | $9,072 |
| Operating expenses | | |
| Cost of natural gas and other products | 15,689 | 7,530 |
| Operation and maintenance | 663 | 562 |
| Merger-related costs and asset impairment charges | 1,161 | 4 |
| Depreciation, depletion, and amortization | 326 | 293 |
| Taxes, other than income taxes | 127 | 76 |
| | 17,966 | 8,465 |
| Operating income (loss) | (212) | 607 |
| Other income | | |
| Earnings from unconsolidated affiliates | 100 | 68 |
| Other, net | 44 | 90 |
| | 144 | 158 |
| Income (loss) before interest, income taxes, and other charges | (68) | 765 |
| Interest and debt expense | 295 | 235 |
| Minority interest | 62 | 42 |
| Income tax expense (benefit) | (35) | 149 |
| | 322 | 426 |
| Income (loss) before extraordinary items | (390) | 339 |
| Extraordinary items, net of income taxes | (10) | 89 |
| Net income (loss) | $ (400) | $ 428 |
| Basic earnings per common share | | |
| Income (loss) before extraordinary items | $ (0.78) | $ 0.69 |
| Extraordinary items, net of income taxes | (0.02) | 0.18 |
| Net income (loss) | $ (0.80) | $ 0.87 |
| Diluted earnings per common share | | |
| Income (loss) before extraordinary items | $ (0.78) | $ 0.67 |
| Extraordinary items, net of income taxes | (0.02) | 0.18 |
| Net income (loss) | $ (0.80) | $ 0.85 |
| Basic average common shares outstanding | 502 | 491 |
| Diluted average common shares outstanding | 502 | 505 |

See accompanying notes.

## EL PASO CORPORATION

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

| | March 31, 2001 | December 31, 2000 |
|---|---|---|
| **ASSETS** | | |
| Current assets | | |
| Cash and cash equivalents | $ 586 | $ 741 |
| Accounts and notes receivable, net | 7,838 | 7,387 |
| Inventory | 1,195 | 1,034 |
| Assets from price risk management activities | 3,749 | 4,825 |
| Other | 1,796 | 832 |
| Total current assets | 15,164 | 14,819 |
| Property, plant, and equipment, at cost | | |
| Pipelines | 14,222 | 14,090 |
| Refining, crude oil, and chemical facilities | 2,384 | 2,606 |
| Power facilities | 687 | 418 |
| Natural gas and oil properties — at full cost | 11,715 | 11,032 |
| Gathering and processing systems | 2,849 | 2,884 |
| Other | 930 | 929 |
| Additional acquisition cost assigned to utility plant | 5,262 | 5,262 |
| | 38,049 | 37,221 |
| Less accumulated depreciation, depletion, and amortization | 15,506 | 14,924 |
| Total property, plant, and equipment, net | 22,543 | 22,297 |
| Other assets | | |
| Investments in unconsolidated affiliates | 4,338 | 4,454 |
| Assets from price risk management activities | 2,725 | 1,776 |
| Other | 3,264 | 2,668 |
| | 10,327 | 8,898 |
| Total assets | $48,034 | $46,014 |

See accompanying notes.

## EL PASO CORPORATION

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

| | March 31, 2001 | December 31, 2000 |
|---|---|---|
| **LIABILITIES AND STOCKHOLDERS' EQUITY** | | |
| Current liabilities | | |
| Accounts and notes payable | $ 8,109 | $ 7,521 |
| Short-term borrowings (including current maturities of long-term debt) | 2,283 | 3,403 |
| Liabilities from price risk management activities | 4,603 | 3,427 |
| Other | 1,104 | 1,324 |
| Total current liabilities | 16,099 | 15,675 |
| Debt | | |
| Long-term debt, less current maturities | 11,857 | 10,902 |
| Notes payable to unconsolidated affiliates | 346 | 343 |
| | 12,203 | 11,245 |
| Deferred credits and other | | |
| Liabilities from price risk management activities | 2,152 | 1,011 |
| Deferred income taxes | 3,855 | 4,106 |
| Deferred credits | 2,239 | 1,451 |
| Other | 877 | 700 |
| | 9,123 | 7,268 |
| Commitments and contingencies | | |
| Securities of subsidiaries | | |
| Company-obligated preferred securities of consolidated trusts | 925 | 925 |
| Minority interests | 2,804 | 2,782 |
| | 3,729 | 3,707 |
| Stockholders' equity | | |
| Common stock, par value $3 per share; authorized 750,000,000 shares; issued 516,883,964 shares in 2001 and 513,815,775 shares in 2000 | 1,551 | 1,541 |
| Additional paid-in capital | 2,237 | 1,925 |
| Retained earnings | 4,726 | 5,235 |
| Accumulated other comprehensive income | (1,127) | (57) |
| Treasury stock (at cost) 7,861,532 shares in 2001 and 13,943,779 shares in 2000 | (260) | (400) |
| Unamortized compensation | (247) | (125) |
| Total stockholders' equity | 6,880 | 8,119 |
| Total liabilities and stockholders' equity | $48,034 | $46,014 |

See accompanying notes.

## EL PASO CORPORATION

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

| | Quarter Ended March 31, 2001 | Quarter Ended March 31, 2000 |
|---|---|---|
| Cash flows from operating activities | | |
| Net income (loss) | $ (400) | $ 428 |
| Adjustments to reconcile net income (loss) to net cash from operating activities | | |
| Depreciation, depletion, and amortization | 326 | 293 |
| Deferred income tax expense (benefit) | (61) | 47 |
| Extraordinary items | 11 | (149) |
| Undistributed earnings of unconsolidated affiliates | (61) | (17) |
| Non-cash portion of merger-related costs and asset impairment charges | 677 | — |
| Other | 38 | (28) |
| Working capital changes, net of non-cash transactions | 282 | (204) |
| Other | 343 | (61) |
| Net cash provided by operating activities | 1,155 | 309 |
| Cash flows from investing activities | | |
| Purchases of property, plant, and equipment | (704) | (938) |
| Additions to investments | (134) | (770) |
| Cash paid for acquisitions, net of cash received | — | (163) |
| Net proceeds from the sale of assets | 171 | 502 |
| Proceeds from the sale of investments | 10 | 192 |
| Repayment of notes receivable from unconsolidated affiliates | 77 | 647 |
| Other | — | 25 |
| Net cash used in investing activities | (580) | (505) |
| Cash flows from financing activities | | |
| Net repayments of commercial paper and short-term notes | (1,120) | (656) |
| Revolving credit borrowings | 295 | 360 |
| Revolving credit repayments | (320) | (395) |
| Payments to retire long-term debt | (657) | (386) |
| Net proceeds from the issuance of long-term debt | 1,596 | 434 |
| Issuances of common stock | 24 | 13 |
| Dividends paid | (60) | (59) |
| Increase (decrease) in notes payable to unconsolidated affiliates | (488) | 463 |
| Net cash used in financing activities | (730) | (226) |
| Decrease in cash and cash equivalents | (155) | (422) |
| Cash and cash equivalents | | |
| Beginning of period | 741 | 589 |
| End of period | $ 586 | $ 167 |

See accompanying notes.

## EL PASO CORPORATION

## CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS) AND CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME
**(In millions)**
**(Unaudited)**

| | Comprehensive Income (Loss) | | Accumulated Other Comprehensive Income (Loss) | |
|---|---|---|---|---|
| | 2001 | 2000 | 2001 | 2000 |
| Net income (loss) for the quarters ended March 31 | $ (400) | $428 | | |
| Other comprehensive income (loss) | | | | |
| Beginning balances as of December 31, 2000 and 1999 | | | $ (57) | $(29) |
| Foreign currency translation adjustments | (14) | (5) | (14) | (5) |
| Unrealized net gains (losses) from cash flow hedging activity | | | | |
| Cumulative-effect transition adjustment (net of tax of $673 million) | (1,280) | — | (1,280) | — |
| Reclassification of initial cumulative-effect transition adjustment at original value (net of tax of $322 million) | 601 | — | 601 | — |
| Additional reclassification adjustments for changes in initial value to settlement date (net of tax of $73 million) | (138) | — | (138) | — |
| Unrealized mark-to-market gains (losses) arising during period (net of tax of $123 million) | (239) | — | (239) | — |
| Balance as of and for periods ended March 31 | $(1,470) | $423 | $(1,127) | $(34) |

See accompanying notes.

## EL PASO CORPORATION

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
**(Unaudited)**

### 1. Basis of Presentation

In January 2001, we completed our merger with The Coastal Corporation. The transaction was accounted for as a pooling of interests, therefore the financial information for all periods presented reflects our combined operations as though our companies had been combined since the earliest period presented. On March 23, 2001, we filed a Current Report on Form 8-K that included audited financial statements reflecting our combined operations for the same periods as required in our 2000 Annual Report on Form 10-K. You should read the Form 8-K and our Form 10-K in conjunction with this Quarterly Report on Form 10-Q. The financial statements at March 31, 2001, and for the quarters ended March 31, 2001 and 2000, are unaudited. The balance sheet at December 31, 2000, is derived from the audited balance sheet filed in the Form 8-K. These financial statements have been prepared pursuant to the rules and regulations of the U.S. Securities and Exchange Commission and do not include all disclosures required by accounting principles generally accepted in the United States. In our opinion, we have made all adjustments, all of which are of a normal, recurring nature (except for merger-related charges described below), to fairly present our interim period results. Information for interim periods may not necessarily indicate the results of operations for the entire year due to the seasonal nature of our businesses. The prior period information also includes reclassifications which were made to conform to the current presentation. These reclassifications have no effect on our reported net income or stockholders' equity.

Our accounting policies are consistent with those discussed in our Form 10-K and our Form 8-K, except as discussed below. You should refer to the Form 10-K and Form 8-K for a further discussion of those policies.

*Accounting for Price Risk Management Activities*

Our business activities expose us to a variety of risks, including commodity price risk, interest rate risk, and foreign currency risk. Our corporate risk management group identifies risks associated with our businesses and determines which risks we want to manage and which types of instruments we should use to manage those risks.

With the adoption of Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivatives and Hedging Activities,* we now record all derivative instruments on the balance sheet at their fair value. These instruments consist of two types, those derivatives entered into and held to mitigate, or hedge a particular risk, and those that are entered into and held for purposes other than risk mitigation, such as those in our trading activities. Those instruments that do not qualify as hedges are recorded at their fair value with changes in fair value reported in current period earnings. For those instruments entered into to hedge risk, and which qualify as hedges under the provisions of SFAS No. 133, the appropriate accounting treatment depends on each instrument's intended use and how it is designated. Derivative instruments that qualify as hedges may be designated as:

- hedges of the fair value of a recognized asset or liability or of an unrecognized firm commitment (fair value hedges);
- hedges of a forecasted transaction or of the variability of cash flows to be received or paid related to a recognized asset or liability (cash flow hedges);
- foreign currency fair value or cash flow hedges (foreign currency hedges); or
- hedges of a net investment in a foreign operation (net investment hedges).

In addition to its designation, a hedge must be effective. To be effective, the value of the derivative or its resulting cash flows must substantially offset changes in the value or cash flows of the item being hedged. If it is determined that the hedge is no longer effective, hedge accounting is discontinued prospectively. Hedge accounting is also discontinued when:

- the derivative instrument expires or is sold, terminated, or exercised;
- it is no longer probable that the forecasted transaction will occur;
- the hedged firm commitment no longer meets the definition of a firm commitment; or
- management determines that the designation of the derivative instrument as a hedge is no longer appropriate.

At the time we enter into a hedge, we formally document relationships between the hedging instrument and the hedged item. This documentation includes:

- the nature of the risk being hedged;
- our risk management objectives and strategies for undertaking the hedging activity;
- a description of the hedged item and the derivative instrument used to hedge the item;
- a description of how effectiveness is tested at the inception of the hedge; and
- how effectiveness will be tested on an ongoing basis.

When hedge accounting is discontinued, the derivative instrument continues to be carried on the balance sheet at its fair value. However, any further changes in its fair value are recognized in current period earnings. Accounting for the item that was being hedged differs depending on how the hedge was originally designated. Our accounting for derivative instruments that qualify as hedges is discussed below:

| Type of Hedge | Accounting Treatment | Impact of the Discontinuation of Hedge Accounting on Item Being Hedged |
|---|---|---|
| Fair value | Changes in the fair value of a derivative that is designated as a fair value hedge and changes in the fair value of the related asset or liability attributable to the hedged risk are recorded in current period earnings, generally as a component of revenue in the case of a sale or as a component of the cost of products in the case of a purchase. | When hedge accounting is discontinued, the hedged asset or liability is no longer adjusted for changes in fair value. When hedge accounting is discontinued because the hedged item no longer meets the definition of a firm commitment, any asset or liability that was recorded related to the firm commitment is removed from the balance sheet and recognized in current period earnings. |
| Cash flow | Changes in the fair value of a derivative designated as a cash flow hedge are recorded in other comprehensive income for the portion of the change in value of the derivative that is effective. The ineffective portion of the derivative is recorded in earnings in the current period. Classification in the income statement of the ineffective portion is based on the income classification of the item being hedged. | When hedge accounting is discontinued because it is unlikely that the forecasted transaction will occur, gains or losses that were accumulated in other comprehensive income related to the forecasted transaction will be recognized immediately in earnings. When a cash flow hedge is de-designated, but the forecasted transaction is still probable, the accumulated amounts remain in other comprehensive income until the forecasted transaction occurs. At that time, the accumulated amounts are recognized in earnings. |
| Foreign currency | Changes in the fair value of a derivative designated as a foreign currency hedge are recorded in current period earnings if it qualifies as a fair value hedge, or in other comprehensive income if it qualifies as a cash flow hedge. | If hedge accounting is discontinued, accounting for the hedged item depends on whether the hedge is a fair value hedge or a cash flow hedge, and follows the accounting discussed above. |

Because our business activities encompass all aspects of the wholesale energy marketplace, including the production, gathering, processing, treating, transmission, refining, and the purchase and sale of highly liquid energy commodities, our normal business contracts may qualify as derivative instruments under the provisions of SFAS No. 133. As a result, we evaluate each of our commercial contracts to see if derivative accounting is appropriate. Contracts that meet the criteria of a derivative are then evaluated to determine whether they qualify as a "normal purchase" or a "normal sale" as those terms are defined in SFAS No. 133. If they qualify, we may document those contracts as normal purchases and normal sales and exclude them from SFAS No. 133 treatment. We also evaluate our contracts for "embedded" derivatives. Embedded derivatives have terms that are not clearly and closely related to the terms of the host contract in which they are included. If embedded derivatives exist, they are accounted for separately from the host contract as derivatives, with changes in their fair value recorded in current period earnings.

**2. Mergers**

In January 2001, we merged with Coastal. We accounted for the transaction as a pooling of interests and converted each share of Coastal common stock and Class A common stock on a tax-free basis into 1.23 shares of our common stock. We exchanged Coastal's outstanding convertible preferred stock for our common stock on the same basis as if the preferred stock had been converted into Coastal common stock immediately prior to the merger. The total value of the transaction was approximately $24 billion, including $7 billion of assumed debt and preferred equity. In the merger, we issued approximately 271 million shares of our common stock, including 4 million shares in exchange for Coastal stock options. All financial information for all periods presented has been restated to reflect the pooling of interests.

The following table presents the revenues and net income for the previously separate companies and the combined amounts presented in these financial statements for the quarter ended March 31, 2000 (in millions).

| | |
|---|---|
| Revenues | |
| El Paso | $3,132 |
| Coastal | 3,597 |
| Conforming reclassifications[1] | 2,343 |
| Combined | $9,072 |
| Extraordinary items, net of income taxes | |
| El Paso | $ 89 |
| Coastal | — |
| Combined | $ 89 |
| Net income | |
| El Paso | $ 254 |
| Coastal | 174 |
| Combined | $ 428 |

[1] Conforming reclassifications include a gross-up of revenues associated with Coastal's physical petroleum marketing and trading activities to be consistent with our method of reporting revenues.

Under a Federal Trade Commission (FTC) order, as a result of our merger with Coastal, we sold our Gulfstream pipeline project, our 50 percent interest in the Stingray pipeline system, and our investment in the Empire pipeline system during the first quarter of 2001. Net proceeds from these sales were approximately $144 million and we recognized an extraordinary net loss of approximately $10 million, net of tax benefits of approximately $1 million. In April 2001, we sold our 50 percent interest in the U-T Offshore pipeline system and our Midwestern system, and in May 2001, we sold our interest in the Iroquois pipeline system. The net proceeds from these sales were approximately $137 million and we will recognize an extraordinary gain of approximately $40 million, net of income taxes of approximately $24 million, in the second quarter of 2001.

Additionally, in the first quarter of 2001, El Paso Energy Partners, L.P. sold its interests in several offshore assets. In April 2001, Energy Partners sold its 50 percent interest in the U-T Offshore pipeline system. These sales consisted of interests in seven natural gas pipeline systems, a dehydration facility, and two offshore platforms. Proceeds from the sales of these assets were approximately $135 million and resulted in a loss to the partnership of approximately $23 million. As consideration for these sales, we committed to pay Energy Partners a series of payments totaling $29 million. We were also required to contribute $40 million to a trust related to one of the assets sold by Energy Partners. We recorded merger-related charges for these payments in our March 31, 2001 income statement.

We do not anticipate the impact from these sales to be material to our ongoing financial position, operating results, or cash flows.

During the first quarter of 2000, we sold East Tennessee Natural Gas Company and Sea Robin Pipeline Company to comply with an FTC order related to our merger with Sonat. Net proceeds from the sales were approximately $457 million and we recognized an extraordinary gain of $89 million, net of income taxes of $60 million.

### 3. Merger-Related Costs and Asset Impairment Charges

During the quarters ended March 31, 2001 and 2000, we incurred merger-related costs associated with our merger with Coastal. These costs included the following for the quarters ended March 31:

| | 2001 | 2000 |
|---|---|---|
| | (In millions) | |
| Employee severance, retention and transition costs | $ 802 | $— |
| Transaction costs | 54 | 4 |
| Merger-related asset impairments | 134 | — |
| Other | 171 | — |
| | $1,161 | $ 4 |

On January 30, 2001, we completed an employee restructuring across all of our operating segments, which resulted in the reduction of 3,285 full-time positions through a combination of early retirements and terminations. Employee severance, retention, and transition costs include direct payments to, and benefit costs for, severed employees and early retirees that occurred as a result of this merger-related workforce reduction and consolidation. These costs include actual severance payments and costs for pension and post-retirement benefits settled and curtailed under existing benefit plans. Retention charges include payments to employees who were retained following the merger and payments to employees to satisfy contractual obligations. Transition costs relate to costs to relocate employees and costs for severed and retired employees arising after their severance date to transition their jobs into the ongoing workforce. The amount of employee severance, retention, and transition costs paid and charged against the accrued amount in the quarter ended March 31, 2001, was approximately $700 million. The remainder of these charges are expected to be paid by the end of 2001.

Also included in employee severance, retention, and transition costs was a charge of $278 million resulting from the issuance of approximately 4 million shares of common stock in exchange for the fair value of Coastal employees' 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.

Merger-related asset impairments relate to write-offs or write-downs of capitalized costs for duplicate systems, redundant facilities and assets whose value was impaired as a result of decisions on the strategic direction of our combined operations following our merger. These charges occurred primarily in our Merchant Energy segment and most of these assets continue to be held for use.

Other costs include charges of approximately $30 million to integrate the facilities and operations of our pipeline and production segments, approximately $65 million related to payments made in satisfaction of obligations arising from the FTC approval of the merger, and approximately $76 million in other charges.

## 4. Earnings Per Share

Our computation of basic and diluted earnings per common share for the quarters ended March 31 is presented below.

| | 2001 | 2000 | |
|---|---|---|---|
| | Basic[1] | Basic | Diluted |
| | (In millions, except per common share amounts) | | |
| Income (loss) before extraordinary items | $ (390) | $ 339 | $ 339 |
| Interest on trust preferred securities and preferred stock dividends, net of income taxes | — | — | 3 |
| Adjusted income (loss) before extraordinary items | (390) | 339 | 342 |
| Extraordinary items, net of income taxes | (10) | 89 | 89 |
| Adjusted net income (loss) | $ (400) | $ 428 | $ 431 |
| Average common shares outstanding | 502 | 491 | 491 |
| Effect of dilutive securities | | | |
| Stock options | — | — | 5 |
| Preferred stock | — | — | 1 |
| Trust preferred securities | — | — | 8 |
| Average common shares outstanding | 502 | 491 | 505 |
| Earnings (loss) per common share | | | |
| Adjusted income (loss) before extraordinary items | $(0.78) | $0.69 | $0.67 |
| Extraordinary items, net of income taxes | (0.02) | 0.18 | 0.18 |
| Adjusted net income (loss) | $(0.80) | $0.87 | $0.85 |

(1) Due to the loss from continuing operations, adding potentially dilutive securities would have an antidilutive effect to earnings per share resulting in a lower loss per share.

## 5. Accounting for Hedging Activities

On January 1, 2001, we adopted the provisions of Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivatives and Hedging Activities.* In accordance with the transition provisions of the statement, we recorded a cumulative-effect adjustment of $1,280 million, net of income taxes, in accumulated other comprehensive income in stockholders' equity to recognize the fair value of all derivatives that we have designated as cash flow hedging instruments. The majority of the initial charge related to hedging forecasted sales of natural gas for 2001 and 2002. During the quarter ended March 31, 2001, $601 million, net of income taxes, of this initial transition adjustment was reclassified to earnings as a result of hedged sales and purchases during the period and an additional $460 million of this adjustment will be reclassified by the end of 2001. A discussion of our hedging activities is as follows:

*Fair Value Hedges.* We have crude oil and refined products inventories that change in value daily due to changes in the commodity markets. We use futures and swaps to protect the value of these inventories. For the quarter ended March 31, 2001, the financial statement impact of our hedges of the fair value of these inventories was immaterial.

*Cash Flow Hedges.* A majority of our commodity sales and purchases are at spot market or forward market prices. In order to reduce volatility of earnings and cash flows, we use futures, forward contracts, and swaps to limit our exposure to fluctuations in the commodity markets and allow for a fixed cash flow stream from these activities. As of March 31, 2001, the value of cash flow hedges included in accumulated other comprehensive income was an unrealized loss of $1,056 million, net of income taxes. Of this amount, we estimate that $793 million will be reclassified from accumulated other comprehensive income over the next 12 months. Reclassifications occur upon physical delivery of the hedged commodity and the corresponding expiration of the hedge. The maximum term of our cash flow hedges is 12 years; however, most of our cash flow hedges expire within the next 24 months.

Our other comprehensive income includes our proportionate share of amounts recorded in other comprehensive income by our unconsolidated affiliates that use derivatives as cash flow hedges.

*Foreign Currency Hedges.* In our international activities, we have fixed rate foreign currency denominated debt that exposes us to changes in exchange rates between the foreign currency and U.S. dollars. During the quarter ended March 31, 2001, we used a currency swap to effectively convert the fixed amounts of foreign currency due under foreign currency denominated debt to fixed U.S. dollar amounts. See Note 7 for further information.

For the quarter ended March 31, 2001, we recognized a net gain of $1 million, net of income taxes, related to the ineffective portion of all cash flow hedges, including foreign currency cash flow hedges.

### 6. Inventory

Our inventory consisted of the following:

| | March 31, 2001 | December 31, 2000 |
|---|---|---|
| | (In millions) | |
| Refined products, crude oil, and chemicals | $ 836 | $ 690 |
| Coal, materials and supplies, and other | 291 | 272 |
| Natural gas in storage | 68 | 72 |
| Total | $1,195 | $1,034 |

### 7. Debt and Other Credit Facilities

At March 31, 2001, our weighted average interest rate on short-term borrowings was 6.2% and at December 31, 2000, it was 7.4%. We had the following short-term borrowings, including current maturities of long-term debt:

| | March 31, 2001 | December 31, 2000 |
|---|---|---|
| | (In millions) | |
| Short-term credit facility | $ 440 | $ 455 |
| Notes payable | — | 343 |
| Commercial paper | 638 | 1,416 |
| Other credit facilities | — | 10 |
| Current maturities of long-term debt | 1,205 | 1,179 |
| | $2,283 | $3,403 |

In December 2000, we established a $700 million floating rate bridge facility for use in connection with our acquisition of PG&E's Texas Midstream operations. As of December 31, 2000, $455 million was outstanding under this facility. At the time of our acquisition, we assumed approximately $527 million in debt, and in February 2001, we borrowed the balance of this facility to redeem $340 million of assumed debt. In March of 2001, we repaid an aggregate principal amount of $260 million of this facility.

In January 2001, we completed the merger with Coastal. Coastal terminated approximately $1.5 billion in revolving credit facilities and became a designated borrower under our 364-day revolving credit and competitive advance facility and our 3-year revolving credit and competitive advance facility.

In February 2001, Southern Natural Gas (SNG) issued $300 million aggregate principal amount 7.35% Notes due 2031. Proceeds of approximately $297 million, net of issuance costs, were used to pay off $100 million of SNG's 8.875% Notes due 2001 and for general corporate purposes. Also in February 2001, we issued approximately $1.8 billion zero coupon convertible debentures due 2021, with a yield to maturity of 4%. Proceeds of approximately $784 million, net of issuance costs, were used to repay short-term borrowings and for general corporate purposes. These debentures are convertible into 8,456,589 shares of our common stock which is based on a conversion rate of 4.7872 shares per $1,000 principal amount at maturity. This rate was equivalent to an initial conversion price of $94.604 per share of our common stock.

In March 2001, we issued €550 million (approximately $510 million) of euro notes at 5.75% due 2006. Proceeds of approximately $505 million, net of issuance costs, were used to repay short-term debt and for general corporate purposes. To reduce our exposure to foreign currency risk, we entered into a swap transaction exchanging the euro note for a $510 million U.S. dollar denominated obligation with a fixed interest rate of 6.61% for the five-year term of the note.

During the first quarter of 2001, we also retired additional long-term debt with an aggregate principal amount of approximately $108 million.

In April 2001, we filed a shelf registration to sell, from time to time, up to a total of $3 billion in debt securities, preferred and common stock, or trust securities, and in May 2001, we issued $500 million aggregate principal amount of 7% Notes due 2011. Net proceeds of approximately $496 million, net of issuance costs, were used to repay our short-term borrowings and for general corporate purposes.

## 8. Commitments and Contingencies

*Legal Proceedings*

On August 19, 2000, a main transmission line owned and operated by El Paso Natural Gas (EPNG) ruptured at the crossing of the Pecos River near Carlsbad, New Mexico. Twelve individuals at the site were fatally injured. Eleven lawsuits brought on behalf of the 12 deceased persons have been filed against us for damages for personal injuries and wrongful death (a list of the *Carlsbad* cases is included in Part II, Item 1). In March 2001, we settled all claims in the *Heady* cases. Payments for these four claimants will be fully covered by insurance. We are cooperating with the National Transportation Safety Board in an investigation into the facts and circumstances concerning the possible causes of the rupture.

In August 2000, the Liquidating Trustee in the bankruptcy of Power Corporation of America (PCA) sued El Paso Merchant Energy (EPME), and several other power traders, in the U.S. Bankruptcy Court in Connecticut claiming EPME improperly cancelled its contracts with PCA during the summer of 1998. The trustee alleges we breached contracts damaging PCA in the amount of $120 million. We have entered into a joint defense agreement with the other defendants. This matter will be mediated in the second quarter of 2001. In a related matter, PCA appealed the Federal Energy Regulatory Commission's (FERC) ruling that power marketers such as EPME did not have to give 60 days notice to cancel its power contracts under the Federal Power Act. PCA has appealed this decision to the United States Court of Appeals. Oral arguments were heard in January 2001, and the court ruled in FERC's favor.

In late 2000, we and several of our subsidiaries were named as defendants in four purported class action lawsuits filed in state courts in Los Angeles and San Diego, California (a list of the *California 2000* cases is included in Part II, Item 1). Two of these cases, filed in Los Angeles, contend generally that our entities conspired with other unrelated companies to create artificially high prices for natural gas in California. The other two cases, filed in San Diego, assert that our companies used EPME's acquisition of capacity on the EPNG pipeline system to manipulate the market for natural gas in California. We have remanded each of these cases to the federal courts in California and have filed motions to dismiss in the San Diego actions. In addition, three additional lawsuits were filed, with two filed in Los Angeles on March 20, 2001, and the third filed on March 22, 2001, on behalf of a purported class in San Francisco (a list of the *California 2001* cases is included in Part II, Item 1). These cases seek monetary damages against us and several of our subsidiaries and make allegations similar to the *California 2000* cases filed in Los Angeles discussed above.

In February 1998, the United States and the state of Texas filed in a U.S. District Court a Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) cost recovery action against 14 companies, including some of our current and former affiliates, related to the Sikes Disposal Pits Superfund Site located in Harris County, Texas. The suit claims that the United States and the state of Texas have spent over $125 million in remediating Sikes and seeks to recover that amount plus interest from the defendants to the suit. The Environmental Protection Agency (EPA) has recently indicated that it may seek an additional amount up to $30 million plus interest in indirect costs from the defendants under a new cost allocation methodology. Defendants are challenging this allocation policy. Although an investigation relating to Sikes is ongoing, we believe that the amount of material, if any, disposed at Sikes by our former affiliates was small, possibly *de minimis*. However, the plaintiffs have alleged that the defendants are each jointly and severally liable for the entire remediation costs and have also sought a declaration of liability for future response costs such as groundwater monitoring.

In 1997, a number of our subsidiaries were named defendants in actions brought by Jack Grynberg on behalf of the U.S. Government under the False Claims Act. Generally, these complaints allege an industry-wide conspiracy to under report the heating value as well as the volumes of the natural gas produced from federal and Native American lands, which deprived the U.S. Government of royalties. These matters have been consolidated for pretrial purposes (In re: Natural Gas Royalties *Qui Tam* Litigation, U.S. District Court for the District of Wyoming).

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.

In October 1992, several property owners in McAllen, Texas filed suit in the 93rd Judicial District Court, Hidalgo County, Texas, against, among others, one of our subsidiaries (*Timely Adventures, Inc. et al,* v. *Phillips Properties, Inc., et al* and *Garza* v. *Coastal Mart, Inc.*). The suit sought damages for the alleged diminution of property value and damages related to the exposure to hazardous chemicals arising from the operation of service stations and storage facilities. In July 2000, the trial court entered a judgment for approximately $1.2 million in actual damages for property diminution and approximately $100 million in punitive damages. The judgment is being appealed.

In November 1988, the Kentucky environmental agency filed a complaint in a Kentucky state court alleging that Tennessee Gas Pipeline (TGP) discharged pollutants into the waters of the state and disposed of polychlorinated biphenyls (PCBs) without a permit. The agency sought an injunction against future discharges, an order to remediate or remove PCBs, and a civil penalty. TGP entered into agreed orders with the agency to resolve many of the issues raised in the original allegations, received water discharge permits from the agency for its Kentucky compressor stations, and continues to work to resolve the remaining issues. The relevant Kentucky compressor stations are being characterized and remediated under a 1994 consent order with the EPA.

We are also a named defendant in numerous lawsuits and a named party in numerous governmental proceedings arising in the ordinary course of our business.

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

*Environmental*

We are subject to extensive federal, state, and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. As of March 31, 2001, we had a reserve of approximately $295 million for expected remediation costs. In addition, we expect to make capital expenditures for environmental matters of approximately $269 million in the aggregate for the years 2001 through 2006. These expenditures primarily relate to compliance with air regulations.

From March to October 2000, our Eagle Point Oil Company received several Administrative Order Notices of Civil Administrative Penalty Assessment from the New Jersey Department of Environmental Protection. All of the assessments are related to similar alleged noncompliances with the New Jersey Air Pollution Control Act pertaining to occurrences of air pollution from the second quarter 1998 through the third quarter 2000 by Eagle Point's refinery in Westville, New Jersey. The New Jersey Department of Environmental Protection has assessed penalties totaling approximately $1 million for these alleged violations. Eagle Point has requested an administrative hearing on all issues raised by the assessments and, concurrently, is in negotiations to settle these assessments.

Since 1988, TGP has been engaged in an internal project to identify and deal with the presence of PCBs and other substances, including those on the EPA List of Hazardous Substances, at compressor stations and other facilities it operates. While conducting this project, TGP has been in frequent contact with federal and state regulatory agencies, both through informal negotiation and formal entry of consent orders, to ensure that its efforts meet regulatory requirements.

In May 1995, following negotiations with its customers, TGP filed a Stipulation and Agreement (the Environmental Stipulation) with FERC that established a mechanism for recovering a substantial portion of the environmental costs identified in its internal project. The Environmental Stipulation was effective July 1, 1995, and as of December 31, 1999, all amounts had been collected from customers. Refunds may be required to the extent actual eligible expenditures are less than amounts collected.

TGP is a party in proceedings involving federal and state authorities regarding the past use of a lubricant containing PCBs in its starting air systems. TGP executed a consent order in 1994 with the EPA governing the remediation of the relevant compressor stations and is working with the EPA and the relevant states regarding those remediation activities. TGP is also working with the Pennsylvania and New York environmental agencies regarding remediation and post-remediation activities at the Pennsylvania and New York stations.

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 29 active sites under 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/or settlements which provide for payment of our allocable share of remediation costs. As of March 31, 2001, we have estimated our share of the remediation costs at these sites to be between $58 million and $194 million and have provided reserves that we believe are adequate for such costs. Since the cleanup costs are estimates and are subject to revision as more information becomes available about the extent of remediation required, and because in some cases we have asserted a defense to any liability, our estimates could change. Moreover, liability under the federal CERCLA statute is joint and several, meaning that we could be required to pay in excess of our pro rata share of remediation costs. Our understanding of the financial strength of other PRPs has been considered, where appropriate, in the determination of our estimated liabilities. We presently believe that the costs associated with these CERCLA sites will not have a material adverse effect on our financial position, operating results, or cash flows.

It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as increasingly strict environmental laws and regulations and claims for damages to property, employees, other persons and the environment resulting from our current or past operations, could result in substantial costs and liabilities in the future. As this information becomes available, or other relevant developments occur, we will adjust our accrual amounts accordingly. While there are still uncertainties relating to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe the recorded reserves are adequate. For a further discussion of specific environmental matters, see Legal Proceedings above.

*Rates and Regulatory Matters*

In April 2000, the California Public Utilities Commission (CPUC) filed a complaint with FERC alleging that EPNG's sale of capacity to EPME was anticompetitive and an abuse of the affiliate relationship under FERC's policies. The CPUC served data requests to us, which were substantially answered or contested. In August 2000, the CPUC filed a motion requesting that the contract between EPNG and EPME be terminated and other parties in the proceedings have requested that the original complaint be set for hearings and that EPME pay back any profits it has earned under the contract. On March 28, 2001, FERC issued an order dismissing arguments that the sale of capacity to EPME violated the marketing affiliate rule and concluded that allegations regarding the awarding of capacity to EPME were unsupported. FERC further established a hearing, before an administrative law judge, to address the issue of whether EPNG and/or EPME had market power and, if so, had exercised it. A hearing date has been set by FERC for mid-May 2001.

In February 2001, EPNG completed its open season on 1,221 million cubic feet per day of capacity held by EPME through May 2001 and all the capacity was re-subscribed. Contracts were awarded to 30 different entities, including 271 million cubic feet per day to EPME, all at published tariff rates under contracts with durations from 17 months to 15 years.

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

## 9. Segment Information

We segregate our business activities into four distinct operating segments: Pipelines, Merchant Energy, Production, and Field Services.

These segments are strategic business units that provide a variety of energy products and services. They are managed separately as each business unit requires different technology and marketing strategies. We measure segment performance using earnings before interest expense and income taxes (EBIT). Following are our results as of and for the periods ended March 31:

| | 2001 | | | | | |
|---|---|---|---|---|---|---|
| | Pipelines | Merchant Energy | Production | Field Services | Other[(1)] | Total |
| | (In millions) | | | | | |
| Revenues from external customers | $ 715 | $15,984 | $ 231 | $ 647 | $ 177 | $17,754 |
| Intersegment revenues | 77 | 425 | 325 | 114 | (941) | — |
| Merger-related costs and asset impairment charges | 89 | 136 | 63 | 29 | 844 | 1,161 |
| Operating income (loss) | 294 | 164 | 188 | 25 | (883) | (212) |
| EBIT | 333 | 258 | 185 | 36 | (880) | (68) |
| Segment assets | 14,046 | 19,311 | 6,922 | 4,018 | 3,737 | 48,034 |

| | 2000 | | | | | |
|---|---|---|---|---|---|---|
| | Pipelines | Merchant Energy | Production | Field Services | Other[(1)] | Total |
| | (In millions) | | | | | |
| Revenues from external customers | $ 691 | $ 7,614 | $ 267 | $ 228 | $ 272 | $ 9,072 |
| Intersegment revenues | 48 | 171 | 111 | 23 | (353) | — |
| Merger-related costs and asset impairment charges | — | — | — | — | 4 | 4 |
| Operating income (loss) | 354 | 72 | 158 | 42 | (19) | 607 |
| EBIT | 390 | 152 | 154 | 55 | 14 | 765 |
| Segment assets | 14,032 | 9,611 | 4,739 | 1,921 | 1,999 | 32,302 |

(1) Includes Corporate and eliminations as well as our telecommunication and retail operations.

## 10. Investments in Unconsolidated Affiliates

We hold investments in various affiliates which we account for using the equity method of accounting. Summarized financial information for our proportionate share of these investments is as follows:

| | Quarter Ended March 31, | |
|---|---|---|
| | 2001 | 2000 |
| | (In millions) | |
| Operating results data | | |
| Revenues and other income | $526 | $1,182 |
| Costs and expenses | 390 | 1,100 |
| Income from continuing operations | 136 | 82 |
| Net income | 100 | 68 |

## 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 Current Report on Form 8-K filed March 23, 2001, in addition to the financial statements and notes presented in Item 1 of this Quarterly Report on Form 10-Q.

### Recent Developments

*Merger with The Coastal Corporation*

In January 2001, we merged with Coastal. We accounted for the merger as a pooling of interests and converted each share of Coastal common stock and Class A common stock on a tax-free basis into 1.23 shares of our common stock. We also exchanged Coastal's outstanding convertible preferred stock for our common stock on the same basis as if the preferred stock had been converted into Coastal common stock immediately prior to the merger. We issued a total of approximately 271 million shares, including 4 million shares issued to holders of Coastal stock options. The management discussion and analysis of financial condition and results of operations presented herein reflects the combined information of our two companies for all periods presented. These results also include merger-related charges as discussed below.

*Merger-Related Costs and Asset Impairment Charges*

During the quarters ended March 31, 2001 and 2000, we incurred, and will continue to incur throughout the remainder of 2001, charges that had and will have a significant impact on our results of operations, financial position, and cash flows. These costs included employee severance, retention, and transition charges; write-offs and write-downs of assets; charges to relocate assets and employees; contract termination charges; and other charges. The table below provides a summary of our merger-related costs and asset impairment charges by each of our business segments, and in total, for the quarters ended March 31:

| | 2001 | 2000 |
|---|---|---|
| | (In millions) | |
| Merger-related costs and asset impairment charges | | |
| Pipelines | $ 89 | $— |
| Merchant Energy | 136 | — |
| Production | 63 | — |
| Field Services | 29 | — |
| Segment total | 317 | — |
| Corporate and other | 844 | 4 |
| Consolidated total | $1,161 | $ 4 |

(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 |
| Btu | = British thermal unit | MMWh | = thousand megawatt hours |
| MBbls | = thousand barrels | | |

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

## Results of Operations

For the quarter ended March 31, 2001, we had a net loss of $400 million versus net income of $428 million for the quarter ended March 31, 2000. The 2001 loss was a result of merger-related costs and asset impairment charges totaling $1,161 million, or $890 million after taxes, related to our merger with Coastal. In addition, we recorded net extraordinary losses totaling $10 million, net of income taxes, as a result of FTC ordered sales of our Gulfstream pipeline project and our investments in the Stingray and Empire pipeline systems. During the first quarter of 2000, merger-related charges were $4 million, or $3 million net of income taxes, and we recorded gains on FTC ordered sales of our East Tennessee and Sea Robin Pipeline systems totaling $89 million, net of income taxes. Net income, excluding the effects of merger-related charges and extraordinary items, was $500 million in 2001 versus $342 million in 2000, or an increase of 46 percent.

EBIT was a loss of $68 million in 2001 versus earnings of $765 million in 2000. Excluding merger-related charges, EBIT was $1,093 million in 2001 versus $769 million in 2000, or an increase of 42 percent. EBIT from the non-regulated segments of our business, which includes our Merchant Energy, Production and Field Services segments, totaled 63 percent of all operating segments, with our pipeline segment contributing 37 percent of the total.

## Segment Results

Our business activities are segregated into four segments: Pipelines, Merchant Energy, Production, and Field Services. These segments are strategic business units that offer a variety of different energy products and services and each requires different technology and marketing strategies. These segments are consistent with those reported by us prior to our merger with Coastal. Coastal's historical segments (natural gas systems; refining, marketing, and chemicals; exploration and production; power; and coal) have been included in the segments in which these businesses are being operated in the combined company, and all prior periods have been restated to reflect this presentation. The results presented in this analysis are not necessarily indicative of the results that would have been achieved had this business segment structure been in place during those periods. 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 portion of our Merchant Energy segment and the Field Services segment. For a further discussion of our individual segments, see Item 1, Financial Statements, Note 9.

| | Quarter Ended March 31, | |
|---|---|---|
| | **2001** | **2000** |
| | **(In millions)** | |
| **Earnings Before Interest Expense and Income Taxes** | | |
| Pipelines | $ 333 | $390 |
| Merchant Energy | 258 | 152 |
| Production | 185 | 154 |
| Field Services | 36 | 55 |
| Segment total | 812 | 751 |
| Corporate and other, net | (880) | 14 |
| Consolidated EBIT | $ (68) | $765 |

**Pipelines**

Our Pipelines segment operates our interstate pipeline businesses. Each pipeline system operates under a separate tariff that governs its operations and rates. Operating results for our pipeline systems have generally been stable because the majority of the revenues are based on fixed demand charges. As a result, we expect changes in this aspect of our business to be primarily driven by regulatory actions and contractual events. Commodity or throughput-based revenues account for a smaller portion of our operating results. These revenues vary from period to period, and system to system, and are impacted by factors such as weather, operating efficiencies, competition from other pipelines, and fluctuations in natural gas prices. Results of operations of the Pipelines segment were as follows for the quarters ended March 31:

| | 2001 | 2000 |
|---|---|---|
| | (In millions, except volume amounts) | |
| Operating revenues | $ 792 | $ 739 |
| Operating expenses | (498) | (385) |
| Other income | 39 | 36 |
| EBIT | $ 333 | $ 390 |
| Throughput volumes (BBtu/d) | | |
| TGP | 5,497 | 5,516 |
| EPNG | 4,826 | 3,934 |
| ANR | 3,938 | 3,898 |
| CIG | 2,557 | 2,243 |
| SNG | 2,231 | 2,813 |
| Equity investments (our proportional share) | 1,993 | 2,220 |
| Total throughput | 21,042 | 20,624 |

Operating revenues for the quarter ended March 31, 2001, were $53 million higher than the same period in 2000. The increase was a result of higher demand revenues on the EPNG system as a result of a larger portion of its capacity earning maximum tariff rates versus the same period in 2000, higher throughput to California and other western states, the impact of higher natural gas prices on sales of production, sales of excess fuel recoveries, and sales under regulated gas sales contracts. These increases were partially offset by lower revenues as a result of the sales of the East Tennessee and Sea Robin pipeline systems in the first quarter of 2000.

Operating expenses for the quarter ended March 31, 2001, were $113 million higher than the same period in 2000 primarily as a result of merger-related charges incurred in 2001 related to the Coastal merger. Also contributing to the increase were higher natural gas prices under regulated natural gas purchase contracts, higher depreciation in 2001 as a result of the approval to reactivate the Elba Island facility which was received in the first quarter of 2000, and increasing plant additions due to capital projects subject to depreciation. Offsetting these increases were reduced operating expenses as a result of the sale of the East Tennessee and Sea Robin pipeline systems in the first quarter of 2000.

Other income for the quarter ended March 31, 2001, was $3 million higher than the same period in 2000 primarily as a result of earnings on our investment in the Alliance pipeline system which was placed in service in the latter part of 2000.

**Merchant Energy**

Merchant Energy is involved in a wide range of activities in the wholesale energy marketplace, including trading and risk management, asset ownership, and financial services. Each market served by Merchant Energy is highly competitive and is influenced directly or indirectly by energy market economics. Prior to October 2000, Coastal conducted its marketing and trading activities through Engage Energy U.S., L.P. and Engage Canada, L.P., a joint venture between Coastal and Westcoast Energy Inc., a Canadian natural gas company. During the fourth quarter of 2000, Coastal terminated the Engage joint venture and commenced its own marketing and trading activities.

Merchant Energy's trading and risk management activities provide energy trading and energy management solutions for its customers and affiliates involving such energy commodities as natural gas, power, crude oil, refined products, chemicals and coal. The segment maintains a substantial trading portfolio that manages its risk across multiple commodities and over seasonally fluctuating energy demands.

Merchant Energy's asset ownership activities include ownership interests in 84 power plants in 20 countries and refining, transportation, and chemical operations, as well as a 20 percent interest in Chaparral Investors, L.L.C., an entity established to acquire, hold, and manage domestic power generation assets. During the quarters ended March 31, 2001 and 2000, Merchant Energy earned $37 million and $20 million in fee-based revenue from Chaparral and was reimbursed $5 million for operating expenses during both periods.

In the financial services area, Merchant Energy owns EnCap Investments and Enerplus Global Energy Management, Inc., and conducts other energy financing activities. EnCap manages three separate oil and natural gas investment funds in the U.S., and serves as an investment advisor to one fund in Europe. EnCap also holds investments in emerging energy companies and earns a return from these investments. In 2000, Merchant Energy acquired Enerplus, a Canadian investment management company through which it conducts fund management activities similar to EnCap, but in Canada. Below are Merchant Energy's operating results and an analysis of those results for each of the quarters ended March 31:

| | 2001 | 2000 |
|---|---|---|
| | (In millions, except volume amounts) | |
| Trading and origination gross margin | $ 205 | $ 48 |
| Operating and other revenues | 5,907 | 5,271 |
| Operating expenses | (5,948) | (5,247) |
| Other income | 94 | 80 |
| EBIT | $ 258 | $ 152 |
| Volumes | | |
| Physical | | |
| Natural gas (BBtue/d) | 13,847 | 5,555 |
| Power (MMWh) | 35,488 | 23,736 |
| Crude oil and refined products (MBbls) | 169,237 | 163,688 |
| Coal (MTons) | 2,663 | 2,474 |
| Financial settlements (BBtue/d) | 247,596 | 138,948 |

Trading and origination gross margin consists of revenues from commodity trading and origination activities less the costs of commodities sold. For the quarter ended March 31, 2001, these gross margins were $157 million higher than the same period in 2000. The increase was primarily due to increased natural gas and power margins resulting from increased trading volumes and price volatility, primarily in the western United States. These increases were partially offset by the income recorded on transportation and storage transactions originating during the first quarter of 2000.

Merchant Energy is a provider of power and natural gas to the state of California. During the latter half of 2000 and continuing into 2001, California experienced sharp increases in natural gas prices and wholesale power prices due to energy shortages resulting from a combination of unusually warm summer weather followed by high winter demand, low gas storage levels, lower hydroelectric power generation, maintenance downtime of significant generation facilities, and price caps that discouraged power movement from other nearby states into California.

The increase in power prices caused by the imbalance of natural gas and power supply and demand coupled with electricity price caps imposed on rates allowed to be charged to California electricity customers has resulted in large cash deficits of the two major California utilities, Southern California Edison and Pacific Gas and Electric. As a result, both utilities have defaulted on payments to creditors and have accumulated substantial under-collections from customers. This resulted in their credit ratings being downgraded in 2001 from above investment grade to below investment grade, and in April 2001, Pacific Gas and Electric filed for bankruptcy. Both utilities have filed for emergency rate increases with the CPUC and are working with the state authorities to restore the companies' financial viability. We have historically been one of the largest suppliers of energy to California, and we are actively participating with all parties in California to be a part of the long-term, stable solution to California's energy needs. As of March 31, 2001, Merchant Energy believes its exposure for sales of power and natural gas to the state of California, including receivables related to its interest in California power plant investments, is less than $50 million, net of credit reserves to reflect market uncertainties.

Chaparral, our investee, has ownership interests in 11 power plants in the state of California. As of March 31, 2001, customers of these facilities had not paid for power generated. This, coupled with Pacific Gas and Electric's bankruptcy declaration, has resulted in an event of default under the terms of each facility's loan agreement. Operations of these plants have been reduced and each facility continues to take necessary actions to enforce the terms of their power purchase agreements. Management of Chaparral has indicated that it believes existing reserves against potential uncollectible accounts are adequate. We do not believe, based on information known to date, that the impact of these matters will have a material impact on our operating results. However, our management fee from Chaparral is based on the value of its assets. As a result, if the value of these power plants is permanently reduced, it could have a similar effect on our management fee in future years.

Operating and other revenues consist of revenues from refineries and chemical plants, consolidated domestic and international power generation facilities, coal operations, and revenues from the financial services businesses of Merchant Energy. For the quarter ended March 31, 2001, operating and other revenues were $636 million higher than the same period in 2000. The increase was as a result of higher realized prices and volumes on refined products, particularly at our Aruba and Corpus Christi refineries, higher management fees on Chaparral, which increased by approximately $17 million in the first quarter of 2001, and revenues from the ManChief power project that commenced operations in July 2000.

Operating expenses for the quarter ended March 31, 2001, were $701 million higher than the same period in 2000. The increase was primarily a result of increased merger-related costs and asset impairment charges associated with combining operations and implementing our combined strategy. We also incurred higher operating and feedstock costs as a result of higher production volumes and feedstock prices at our refineries, and higher operating expenses and depreciation associated with the ManChief power facility.

Other income for the quarter ended March 31, 2001, was $14 million higher than the same period in 2000. We experienced higher equity earnings from an increased ownership interest in the Eagle Point power generation facility, higher earnings from our investment in CE Generation as a result of higher power prices in California, and higher interest income on over-the-counter margin deposits. The increase was partially offset by gains in the first quarter of 2000 from the transfer of a portion of our interest in East Asia Power, income recorded in the first quarter 2000 related to mark-to-market increases on a swap on our CAPSA investment, and the first quarter 2000 gain reported from the sale of our interest in a power project in Guatemala.

### Production

Production's operating results are driven by a variety of factors including its ability to locate and develop economic reserves, extract those reserves with minimal production costs, sell the products at attractive commodity prices, and operate at the lowest cost level possible.

Production engages in hedging activities on its natural gas and oil production in order to stabilize cash flows and reduce the risk of downward commodity price movements on sales of its production. This is achieved through natural gas and oil swaps. We attempt to hedge approximately 75 percent of our anticipated current year production and approximately 50 percent of our anticipated succeeding year production. Production's hedged positions are closely monitored and evaluated in an effort to achieve its earnings objectives and reduce the risks associated with spot-market price volatility. Below are the operating results and analysis of these results for the quarters ended March 31:

| | 2001 | 2000 |
|---|---|---|
| | (In millions, except volumes and prices) | |
| Natural gas | $ 466 | $ 312 |
| Oil, condensate, and liquids | 86 | 62 |
| Other | 4 | 4 |
| Total operating revenues | 556 | 378 |
| Operating expenses | (368) | (220) |
| Other loss | (3) | (4) |
| EBIT | $ 185 | $ 154 |
| Volumes and prices | | |
| Natural gas | | |
| Volumes (MMcf) | 133,944 | 126,321 |
| Average realized prices ($/Mcf) | $ 3.48 | $ 2.47 |
| Oil, condensate and liquids | | |
| Volumes (MBbls) | 3,134 | 2,963 |
| Average realized prices ($/Bbl) | $ 27.42 | $ 20.99 |

For the quarter ended March 31, 2001, operating revenues were $178 million higher than the same period in 2000. The increase was the combined result of higher production coupled with higher realized natural gas prices. Natural gas production volumes rose during the first quarter 2001 by 6 percent over 2000, and realized sales prices were 41 percent higher than the first quarter 2000. Oil, condensate, and liquids production volumes were also 6 percent higher than the same period in 2000, with realized average prices increasing 31 percent.

Operating expenses for the quarter ended March 31, 2001, were $148 million higher than the same period in 2000 as a result of merger-related charges during the first quarter of 2001 related to integrating our combined production operations, higher production costs due to increased oilfield services costs, and higher severance and other production taxes in 2001, which are generally tied to natural gas and oil prices. Also contributing to the increase was higher depreciation, depletion, and amortization expense in 2001 as a result of the increased production volumes and higher capitalized costs in the full cost pool.

### Field Services

Field Services provides a variety of services for the midstream component of our operations, including gathering and treating of natural gas, processing and fractionation of natural gas, natural gas liquids and natural gas derivative products, such as ethane, propane, and butane. A subsidiary of Field Services also serves as the general partner of Energy Partners, a publicly traded master limited partnership. As the general partner, Field Services earns a combination of management fees and partner distributions for services rendered to Energy Partners. Field Services attempts to balance its earnings from its activities through a combination of contractually-based and market-based services.

Our gathering and treating operations earn margins substantially from fixed-fee based services; however, some of these operations earn margins from commodity-based rates. Revenues for these commodity rate services are the product of the market price, usually related to the monthly natural gas price index, and the volume gathered.

Processing and fractionation operations earn a margin based on fixed-fee contracts, percentage-of-proceeds contracts, and make-whole contracts. Percentage-of-proceeds contracts allow us to retain a percentage of the product as a fee for processing or fractionation service. Make-whole contracts allow us to retain the extracted liquid products and return to the producer a Btu equivalent amount of natural gas. Under our percentage-of-proceeds contracts and make-whole contracts, Field Services may have more sensitivity to price changes during periods when natural gas and natural gas liquids prices are volatile.

Field Services' operating results and an analysis of those results are as follows for the quarters ended March 31:

| | 2001 | 2000 |
|---|---|---|
| | (In millions, except volumes and prices) | |
| Gathering and treating margin | $ 88 | $ 58 |
| Processing margin | 63 | 59 |
| Other margin | 3 | (4) |
| Total gross margin | 154 | 113 |
| Operating expenses | (129) | (71) |
| Other income | 11 | 13 |
| EBIT | $ 36 | $ 55 |
| Volumes and prices | | |
| Gathering and treating | | |
| Volumes (BBtu/d) | 8,427 | 5,448 |
| Prices ($/MMBtu) | $ 0.15 | $ 0.16 |
| Processing | | |
| Volumes (inlet BBtu/d) | 3,892 | 2,925 |
| Prices ($/MMBtu) | $ 0.18 | $ 0.17 |

Total gross margin for the quarter ended March 31, 2001, was $41 million higher than the same period in 2000. The increase was a result of higher gathering and treating margins, which increased approximately 52 percent, primarily due to higher San Juan gathering rates along with higher volumes as a result of our acquisition of PG&E's Texas Midstream operations in December 2000. Processing margins in 2001 were also higher, increasing 7 percent over 2000, as a result of contributions from the processing operations acquired from PG&E.

Operating expenses for the quarter ended March 31, 2001, were $58 million higher than the same period in 2000. The increase was a result of higher operating costs from the addition of PG&E's Texas Midstream operations, merger-related costs arising from payments made to Energy Partners related to FTC ordered sales of assets owned by the partnership, and higher corporate allocations as a result of growth in the midstream segment.

Other income for the quarter ended March 31, 2001, was $2 million lower than the same period in 2000. Higher earnings in 2001 from our interests in Energy Partners were more than offset by first quarter 2000 gains on the sales of the Colorado dry gathering system and other operating assets in the first quarter 2000.

## Corporate and Other, net

Corporate expenses, which also include results from our retail gas stations and telecommunications businesses, were $894 million higher for the quarter ended March 31, 2001, versus the same period in 2000. The increase was primarily a result of merger-related charges in connection with our January 2001 merger with Coastal. Net costs associated with our telecommunications business during the first quarter of 2001 were approximately $5 million.

## Interest and Debt Expense

Interest and debt expense for the quarter ended March 31, 2001, was $60 million higher than 2000. The increase was a result of higher average borrowings in 2001 for ongoing capital projects, investment programs, and operating requirements. We also had an increase in average short-term borrowings related to our commercial paper program and revolving credit facility. We anticipate interest and debt expense will continue to exceed last year's levels throughout the remainder of 2001.

## Minority Interest

Minority interest for the quarter ended March 31, 2001, was $20 million higher than for 2000 due to the sale of additional preferred interests in Clydesdale Associates, L.P., in the fourth quarter of 2000.

For a further discussion of our borrowing and other financing activities during the period, see Part I, Financial Information, Note 7.

## Income Tax Expense

The income tax benefit was $35 million for the quarter ended March 31, 2001, resulting in an effective tax rate of 8 percent. Our effective tax rate was different than the statutory rate of 35 percent primarily due to the following:

- the non-deductible portion of merger-related costs and other tax adjustments to provide for revised estimated liabilities;
- state income taxes;
- earnings from unconsolidated affiliates where we anticipate receiving dividends; and
- foreign income, not taxed in the U.S., but taxed at foreign rates.

Income tax expense was $149 million for the quarter ended March 31, 2000, resulting in an effective tax rate of 31 percent. Our effective tax rate was different than the statutory rate of 35 percent primarily due to the following:

- state income taxes;
- earnings from unconsolidated affiliates where we anticipate receiving dividends; and
- foreign income, not taxed in the U.S., but taxed at foreign rates.

## Liquidity and Capital Resources

### Cash From Operating Activities

Net cash provided by our operating activities was $1,155 million for the quarter ended March 31, 2001, compared to $309 million for 2000. The increase was primarily a result of higher cash generated from our price risk management activities related to the substantial growth in our trading portfolio compared to 2000. We also had lower income tax payments in 2001. Partially offsetting these increases were cash payments in 2001 for charges related to the merger with Coastal and higher interest payments.

### Cash From Investing Activities

Net cash used in our investing activities was $580 million for the quarter ended March 31, 2001. Our investing activities principally consisted of additions to property, plant, and equipment, including an increase in our oil and natural gas properties for development drilling and expenditures for expansion and construction projects. We also had additions to joint ventures and investments in unconsolidated affiliates, primarily related to our investment in El Paso Energy Araucaria Company (an international power company), and additions of short-term notes from unconsolidated affiliates. Cash inflows from investment-related activities included proceeds from the sales of our Gulfstream pipeline project, our interest in the Empire pipeline system and proceeds from the sales of over 200 of our retail stores.

### Cash From Financing Activities

Net cash used in our financing activities was $730 million for the quarter ended March 31, 2001. During 2000, we repaid short-term borrowings and notes to unconsolidated affiliates, retired long-term debt, and paid dividends. Cash provided from our financing activities included the issuance of long-term debt and issuances of common stock as a result of the exercise of employee stock options.

We expect that future funding for working capital needs, capital expenditures, acquisitions, other investing activities, long-term debt retirements, payments of dividends and other financing expenditures will be provided by internally generated funds, commercial paper issuances, available capacity under existing credit facilities, and the issuance of new long-term debt, trust securities, or equity.

The following table reflects quarterly dividends declared and paid on our common stock:

| Declaration Date | Amount Per Common Share | Payment Date | Total Amount (In millions) |
|---|---|---|---|
| Coastal | | | |
| November 1, 2000 | $0.0625 | January 1, 2001 | $ 13 |
| El Paso | | | |
| October 26, 2000 | $0.2060 | January 2, 2001 | $ 49 |
| January 24, 2001 | $0.2125 | April 2, 2001 | $108 |

In April 2001, we declared a quarterly dividend of $0.2125 per share on our common stock, payable on July 2, 2001, to stockholders of record on June 1, 2001. Also, during the quarter ended March 31, 2001, we paid dividends of $6 million on the 8¼% Series A cumulative preferred stock of our subsidiary, El Paso Tennessee Pipeline Co.

## Commitments and Contingencies

See Part I, Financial Information, Note 8, which is incorporated by reference herein.

## CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

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

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

Important factors that could cause actual results to differ materially from estimates or projections contained in forward-looking statements include, among others, the following:

- the ability to successfully integrate Coastal's operations and PG&E's Texas Midstream operations;
- the increasing competition within our industry;
- the timing and extent of changes in commodity prices for natural gas and power;
- the uncertainties associated with customer contract expirations on our pipeline systems;
- the potential contingent liabilities and tax liabilities related to our acquisitions;
- the political and economic risks associated with current and future operations in foreign countries; and
- the conditions of equity and other capital markets.

These risk factors are more fully described in our other filings with the Securities and Exchange Commission, including our Current Report on Form 8-K filed March 23, 2001.

### Item 3. Quantitative and Qualitative Disclosures About Market Risk

There are no material changes in our quantitative and qualitative disclosures about market risks from those reported in our Current Report on Form 8-K filed March 23, 2001.

## PART II — OTHER INFORMATION

### Item 1. Legal Proceedings

See Part I, Financial Information, Note 8, which is incorporated by reference herein.

The eleven *Carlsbad* lawsuits are as follows: three were filed in district court in Harris County, Texas (*Diane Heady, et al v. El Paso Energy Corporation (EPEC) and EPNG,* filed September 7, 2000 and settled in March 2001; *Richard Heady, et al v. EPEC and EPNG,* filed February 15, 2001 and settled in March 2001; and *Geneva Smith, et al v. EPEC and EPNG,* filed October 23, 2000), two were filed in federal district court in Albuquerque, New Mexico (*Dawson, as Personal Representative of Kirsten Janay Sumler, v. EPEC and EPNG,* filed November 8, 2000 and *Jennifer Smith, et al v. EPEC and EPNG,* filed August 29, 2000), and six were filed in state district court in Carlsbad, New Mexico (*Chapman, as Personal Representative of the Estate of Amy Smith Heady, v. EPEC, EPNG, and John Cole,* filed February 9, 2001; and *Chapman, as Personal Representative of the Estate of Dustin Wayne Smith, v. EPEC, EPNG and John Cole; Chapman, as Personal Representative of the Estate of Terry Wayne Smith, v. EPNG, EPEC, and John Cole; Green, as Personal Representative of the Estate of Jesse Don Sumler, v. EPEC, EPNG, and John Cole; Rackley, as Personal Representative of the Estate of Glenda Gail Sumler, v. EPEC, EPNG, and John Cole;* and *Rackley, as Personal Representative of the Estate of Amanda Sumler Smith, v. EPEC, EPNG, and John Cole,* all filed March 16, 2001).

The *California 2000* cases are: two filed in the Superior Court of Los Angeles County (*Continental Forge Company, et al v. Southern California Gas Company, et al,* filed on September 25, 2000; and *Berg v. Southern California Gas Company, et al,* filed on December 18, 2000); and two filed in the Superior Court of San Diego County (*John W.H.K. Phillip v. El Paso Merchant Energy* and *John Phillip v. El Paso Merchant Energy,* both filed on December 13, 2000). The *California 2001* cases are: two filed in the Superior Court of Los Angeles County (*The City of Los Angeles, et al v. Southern California Gas Company, et al* and *The City of Long Beach, et al v. Southern California Gas Company, et al,* both filed on March 20, 2001); and one filed in the Superior Court of San Francisco County (*Sweeties v. El Paso Corporation, et al,* filed on March 22, 2001).

### Item 2. Changes in Securities and Use of Proceeds

None.

### Item 3. Defaults Upon Senior Securities

None.

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

None.

### Item 5. Other Information

None.

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

a. Exhibits

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

| Exhibit Number | Description |
|---|---|
| 3.A | — Restated Certificate of Incorporation of El Paso as filed with the Delaware Secretary of State on February 7, 2001 (Exhibit 3.A to El Paso's Form 8-K, filed February 14, 2001). |
| 3.B | — Restated By-laws of El Paso (Exhibit 3.B to El Paso's Form 8-K dated February 14, 2001). |
| *+10.E.1 | — Amendment No. 3 to the 1995 Compensation Plan for Non-Employee Directors effective as of February 7, 2001. |
| *+10.F.1 | — Amendment No. 2 to the Stock Option Plan for Non-Employee Directors effective as of February 7, 2001. |
| *+10.H.1 | — Amendment No. 2 to the Supplemental Benefits Plan effective as of February 7, 2001. |
| *+10.I.1 | — Amendment No. 1 to the Senior Executive Survivor Benefit Plan effective as of February 7, 2001. |
| *+10.J.1 | — Amendment No. 2 to the Deferred Compensation Plan effective as of February 7, 2001. |
| *+10.K.1 | — Amendment No. 1 to the Key Executive Severance Protection Plan effective as of February 7, 2001. |
| *+10.L.1 | — Amendment No. 1 to the Director Charitable Award Plan effective as of February 7, 2001. |
| *+10.M.1 | — Amendment No. 1 to the Strategic Stock Plan effective as of February 7, 2001. |
| *+10.T.2 | — Amendment No. 5 to the Employee Stock Purchase Plan effective as of February 7, 2001. |
| *+10.U.1 | — Amendment No. 2 to the Omnibus Plan for Management Employees effective as of February 7, 2001. |
| *+10.V.1 | — Amendment No. 1 to the 1999 Omnibus Incentive Compensation Plan effective as of February 7, 2001. |

Undertaking

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

b. Reports on Form 8-K

- We filed a current report on Form 8-K, dated January 3, 2001, announcing the completion of our acquisition of PG&E's Texas Midstream operations.
- We filed a current report on Form 8-K, dated January 29, 2001, announcing the completion of our merger with The Coastal Corporation.
- We filed a current report on Form 8-K, dated February 5, 2001, announcing the completion of our merger with The Coastal Corporation and the exchange and issuance of shares of El Paso.
- We filed a current report on Form 8-K, dated February 6, 2001, announcing our name change to El Paso Corporation.
- We filed a current report on Form 8-K, dated February 14, 2001, announcing several events, including the opening of a New European Trading floor, the Purchase of Texas Midstream Operations, Recent Developments in California, the Approval of a Dividend Increase, the Announcement of Record Earnings, the Completion of Post Merger Restructuring, and our 2001 Analysts Meetings.
- We filed a current report on Form 8-K/A, dated February 21, 2001, announcing information on debt issuances and clarifying items contained in the February 14, 2001 Form 8-K.
- We filed a current report on Form 8-K, dated February 23, 2001, announcing plans to offer a private offering of zero coupon convertible debentures, convertible into El Paso common stock.
- We filed a current report on Form 8-K, dated March 2, 2001, announcing our combined operating results for the first 30 days following our merger with Coastal.
- We filed a current report on Form 8-K, dated March 23, 2001, announcing the completion of the merger with Coastal and reporting financials on a combined basis.
- We filed a current report on Form 8-K, dated March 26, 2001, clarifying charges taken as part of the required implementation of SFAS No. 133 and reflected in our 2000 Form 10-K.
- We filed a current report on Form 8-K, dated March 29, 2001, commenting on the FERC's ruling in response to a complaint filed by the CPUC.

## SIGNATURES

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

EL PASO CORPORATION

Date: May 11, 2001

/s/ H. BRENT AUSTIN

H. Brent Austin
*Executive Vice President and*
*Chief Financial Officer*

Date: May 11, 2001

/s/ JEFFREY I. BEASON

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