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

# Form 10-Q

(Mark One)

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

**For the quarterly period ended September 30, 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 November 6, 2001: 510,314,253

## PART I — FINANCIAL INFORMATION

**Item 1. Financial Statements**

### EL PASO CORPORATION

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

| | Quarter Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2001 | 2000 | 2001 | 2000 |
| Operating revenues | $13,845 | $13,468 | $45,324 | $32,580 |
| Operating expenses | | | | |
| Cost of natural gas and other products | 12,040 | 11,951 | 39,642 | 27,992 |
| Operation and maintenance | 732 | 567 | 2,220 | 1,690 |
| Merger-related costs and asset impairments | 32 | 3 | 1,794 | 56 |
| Ceiling test charges | 135 | — | 135 | — |
| Depreciation, depletion and amortization | 346 | 305 | 1,005 | 902 |
| Taxes, other than income taxes | 80 | 70 | 307 | 224 |
| | 13,365 | 12,896 | 45,103 | 30,864 |
| Operating income | 480 | 572 | 221 | 1,716 |
| Other income | | | | |
| Earnings from unconsolidated affiliates | 102 | 127 | 302 | 297 |
| Other, net | 66 | 45 | 207 | 180 |
| | 168 | 172 | 509 | 477 |
| Income before interest, income taxes and other charges | 648 | 744 | 730 | 2,193 |
| Interest and debt expense | 279 | 273 | 865 | 757 |
| Minority interest | 51 | 54 | 169 | 145 |
| Income taxes | 102 | 135 | 4 | 409 |
| | 432 | 462 | 1,038 | 1,311 |
| Income (loss) before extraordinary items | 216 | 282 | (308) | 882 |
| Extraordinary items, net of income taxes | (5) | — | 26 | 89 |
| Net income (loss) | $ 211 | $ 282 | $ (282) | $ 971 |
| Basic earnings per common share | | | | |
| Income (loss) before extraordinary items | $ 0.43 | $ 0.57 | $ (0.61) | $ 1.79 |
| Extraordinary items, net of income taxes | (0.01) | — | 0.05 | 0.18 |
| Net income (loss) | $ 0.42 | $ 0.57 | $ (0.56) | $ 1.97 |
| Diluted earnings per common share | | | | |
| Income (loss) before extraordinary items | $ 0.42 | $ 0.55 | $ (0.61) | $ 1.74 |
| Extraordinary items, net of income taxes | (0.01) | — | 0.05 | 0.18 |
| Net income (loss) | $ 0.41 | $ 0.55 | $ (0.56) | $ 1.92 |
| Basic average common shares outstanding | 506 | 495 | 504 | 493 |
| Diluted average common shares outstanding | 520 | 517 | 504 | 511 |
| Dividends declared per common share | $ 0.21 | $ 0.21 | $ 0.64 | $ 0.62 |

See accompanying notes.

## EL PASO CORPORATION

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

| | September 30, 2001 | December 31, 2000 |
|---|---|---|
| **ASSETS** | | |
| Current assets | | |
| Cash and cash equivalents | $ 777 | $ 741 |
| Accounts and notes receivable, net | | |
| Customer | 5,334 | 6,188 |
| Unconsolidated affiliates | 906 | 304 |
| Other | 842 | 896 |
| Inventory | 980 | 1,370 |
| Assets from price risk management activities | 2,797 | 4,825 |
| Other | 1,199 | 832 |
| Total current assets | 12,835 | 15,156 |
| Property, plant and equipment, at cost | | |
| Pipelines | 14,771 | 14,090 |
| Refining, crude oil and chemical facilities | 2,324 | 2,606 |
| Power facilities | 741 | 383 |
| Natural gas and oil properties, at full cost | 13,170 | 11,032 |
| Gathering and processing systems | 2,844 | 2,884 |
| Other | 968 | 929 |
| | 34,818 | 31,924 |
| Less accumulated depreciation, depletion and amortization | 15,948 | 14,924 |
| | 18,870 | 17,000 |
| Additional acquisition cost assigned to utility plant, net | 5,190 | 5,262 |
| Total property, plant and equipment, net | 24,060 | 22,262 |
| Other assets | | |
| Investments in unconsolidated affiliates | 4,644 | 4,392 |
| Assets from price risk management activities | 2,250 | 1,776 |
| Other | 3,329 | 2,728 |
| | 10,223 | 8,896 |
| Total assets | $47,118 | $46,314 |

See accompanying notes.

## EL PASO CORPORATION

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

| | September 30, 2001 | December 31, 2000 |
|---|---|---|
| **LIABILITIES AND STOCKHOLDERS' EQUITY** | | |
| Current liabilities | | |
| Accounts and notes payable | | |
| Trade | $ 5,784 | $ 5,143 |
| Unconsolidated affiliates | 13 | 14 |
| Other | 1,238 | 1,968 |
| Short-term borrowings (including current maturities of long-term debt) | 2,773 | 3,799 |
| Liabilities from price risk management activities | 1,778 | 3,427 |
| Other | 2,184 | 1,324 |
| Total current liabilities | 13,770 | 15,675 |
| Debt | | |
| Long-term debt, less current maturities | 12,371 | 10,903 |
| Notes payable to unconsolidated affiliates | 370 | 343 |
| | 12,741 | 11,246 |
| Other | | |
| Liabilities from price risk management activities | 1,367 | 1,010 |
| Deferred income taxes | 4,097 | 4,106 |
| Other | 3,112 | 2,451 |
| | 8,576 | 7,567 |
| Commitments and contingencies | | |
| Securities of subsidiaries | | |
| Company-obligated preferred securities of consolidated trusts | 925 | 925 |
| Minority interests | 2,782 | 2,782 |
| | 3,707 | 3,707 |
| Stockholders' equity | | |
| Common stock, par value $3 per share; authorized 750,000,000 shares; issued 517,895,002 shares in 2001 and 513,815,775 shares in 2000 | 1,554 | 1,541 |
| Additional paid-in capital | 2,256 | 1,925 |
| Retained earnings | 4,634 | 5,243 |
| Accumulated other comprehensive income | 343 | (65) |
| Treasury stock (at cost) 7,638,507 shares in 2001 and 13,943,779 shares in 2000 | (261) | (400) |
| Unamortized compensation | (202) | (125) |
| Total stockholders' equity | 8,324 | 8,119 |
| Total liabilities and stockholders' equity | $47,118 | $46,314 |

See accompanying notes.

## EL PASO CORPORATION

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

| | Nine Months Ended September 30, 2001 | Nine Months Ended September 30, 2000 |
|---|---|---|
| Cash flows from operating activities | | |
| Net income (loss) | $ (282) | $ 971 |
| Adjustments to reconcile net income (loss) to net cash from operating activities | | |
| Depreciation, depletion and amortization | 1,005 | 902 |
| Ceiling test charges | 135 | — |
| Deferred income tax expense (benefit) | (10) | 401 |
| Net gain on the sale of assets | (16) | (28) |
| Extraordinary items | (53) | (149) |
| Undistributed earnings of unconsolidated affiliates | (77) | (70) |
| Non-cash portion of merger-related costs, asset impairments and changes in estimates | 1,587 | — |
| Non-cash portion of price risk management activities | (305) | (140) |
| Other | 34 | (15) |
| Working capital changes, net of non-cash transactions | | |
| Change in price risk management activities | 1,334 | (1,327) |
| Other working capital changes | 450 | (80) |
| Non-working capital changes and other | (426) | (96) |
| Net cash provided by operating activities | 3,376 | 369 |
| Cash flows from investing activities | | |
| Additions to property, plant and equipment | (2,836) | (2,454) |
| Additions to investments | (1,290) | (1,355) |
| Cash paid for acquisitions, net of cash acquired | (232) | (197) |
| Net proceeds from the sale of assets | 384 | 507 |
| Proceeds from the sale of investments | 266 | 340 |
| Repayment of notes receivable from unconsolidated affiliates | 253 | 647 |
| Other | — | 24 |
| Net cash used in investing activities | (3,455) | (2,488) |
| Cash flows from financing activities | | |
| Net repayments of commercial paper and short-term notes | (397) | (167) |
| Revolving credit borrowings | 725 | 545 |
| Revolving credit repayments | (990) | (520) |
| Payments to retire long-term debt | (1,599) | (714) |
| Net proceeds from the issuance of long-term debt | 2,888 | 1,615 |
| Net proceeds from the issuance of preferred securities | — | 293 |
| Issuances of common stock | 46 | 101 |
| Dividends paid | (278) | (180) |
| Net proceeds from the issuance of minority interests in subsidiaries | — | 245 |
| Increase in notes payable to unconsolidated affiliates | 50 | 1,040 |
| Decrease in notes payable to unconsolidated affiliates | (479) | (398) |
| Net proceeds from the issuance of notes payable | 221 | 58 |
| Repayment of notes payable | (72) | (82) |
| Net cash provided by financing activities | 115 | 1,836 |
| Increase (decrease) in cash and cash equivalents | 36 | (283) |
| Cash and cash equivalents | | |
| Beginning of period | 741 | 589 |
| End of period | $ 777 | $ 306 |

See accompanying notes.

## EL PASO CORPORATION

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

| Comprehensive Income | Quarter Ended September 30, 2001 | Quarter Ended September 30, 2000 | Nine Months Ended September 30, 2001 | Nine Months Ended September 30, 2000 |
|---|---|---|---|---|
| Net income (loss) | $ 211 | $282 | $ (282) | $971 |
| Unrealized net gains (losses) from cash flow hedging activity | | | | |
| Cumulative-effect transition adjustment (net of tax of $673) | — | — | (1,280) | — |
| Reclassification of initial cumulative-effect transition adjustment at original value (net of tax of $80 and $499) | 149 | — | 931 | — |
| Additional reclassification adjustments for changes in initial value to settlement date (net of tax of $126 and $161) | (235) | — | (335) | — |
| Unrealized mark-to-market gains arising during period (net of tax of $260 and $587) | 462 | — | 1,114 | — |
| Other | (4) | (4) | (22) | (13) |
| Comprehensive income | $ 583 | $278 | $ 126 | $958 |

| Accumulated Other Comprehensive Income | 2001 | 2000 |
|---|---|---|
| Beginning balances as of December 31, 2000 and 1999 | $ (65) | $(29) |
| Unrealized net gains (losses) from cash flow hedging activity | | |
| Cumulative-effect transition adjustment, net of taxes | (1,280) | — |
| Reclassification of initial cumulative-effect transition adjustment at original value, net of taxes | 931 | — |
| Additional reclassification adjustments for changes in initial value to settlement date, net of taxes | (335) | — |
| Unrealized mark-to-market gains arising during period, net of taxes | 1,114 | — |
| Other | (22) | (13) |
| Balance as of September 30, | $ 343 | $(42) |

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 in this Quarterly Report on Form 10-Q reflects our operations as though our companies had been combined since the earliest period presented. On May 17, 2001, we filed a Current Report on Form 8-K/A that included combined audited financial statements for the same periods as required in our 2000 Annual Report on Form 10-K. You should read that Form 8-K/A in conjunction with this Quarterly Report on Form 10-Q. The financial statements as of September 30, 2001, and for the quarters and nine months ended September 30, 2001 and 2000, are unaudited. The balance sheet as of December 31, 2000, is derived from the audited balance sheet filed in the Form 8-K/A. These financial statements have been prepared pursuant to the rules and regulations of the U.S. Securities and Exchange Commission and do not include all disclosures required by accounting principles generally accepted in the United States. In our opinion, we have made all adjustments, all of which are of a normal, recurring nature (except for merger-related costs, asset impairments, changes in estimates and ceiling test charges, all discussed below), to fairly present our interim period results. Information for interim periods may not necessarily indicate the results of operations for the entire year due to the seasonal nature of our businesses. The prior period information also includes reclassifications which were made to conform to the current period presentation. These reclassifications have no effect on our reported net income or stockholders' equity.

Our accounting policies are consistent with those discussed in our Form 8-K/A, except as discussed below. You should refer to the Form 8-K/A 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.

We record all derivative instruments on the balance sheet at their fair value under the provisions of Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivatives and Hedging Activities*. 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, we apply the provisions of SFAS No. 133, and the accounting treatment depends on each instrument's intended use and how it is designated. Derivative instruments that qualify as hedges may be designated as fair value hedges, cash flow hedges, foreign currency hedges or net investment hedges as defined in SFAS No. 133.

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 policies for derivative instruments used in our business that qualify as hedges are 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 the derivative 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 the derivative 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 no longer probable 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 the derivative 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 as normal purchases and normal sales, we may 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 contract in which they are included. If embedded derivatives exist, they are accounted for separately from the host contract, with changes in their fair value recorded in current period earnings.

## 2. Merger with Coastal

In January 2001, we merged with Coastal. We accounted for the transaction as a pooling of interests and converted each share of Coastal's 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 issued in exchange for Coastal stock options.

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 periods ended September 30:

| | Quarter Ended September 30, 2000 | Nine Months Ended September 30, 2000 |
|---|---|---|
| | (In millions) | |
| Revenues | | |
| El Paso | $ 7,025 | $14,407 |
| Coastal | 4,366 | 11,955 |
| Conforming reclassifications[(1)] | 2,077 | 6,218 |
| Combined | $13,468 | $32,580 |
| Extraordinary items, net of income taxes | | |
| El Paso | $ — | $ 89 |
| Coastal | — | — |
| Combined | $ — | $ 89 |
| Net income | | |
| El Paso | $ 137 | $ 525 |
| Coastal | 145 | 446 |
| Combined | $ 282 | $ 971 |

(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 these revenues.

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

Additionally, El Paso Energy Partners, L.P. sold its interests in several offshore assets. These sales consisted of interests in eight 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 $25 million. As consideration for these sales, we committed to pay El Paso 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 El Paso Energy Partners. These payments have been recorded as merger-related costs.

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

During the nine months ended September 30, 2000, we sold East Tennessee Natural Gas Company, Sea Robin Pipeline Company and our one-third interest in Destin Pipeline Company to comply with an FTC order related to our merger with Sonat Inc. Net proceeds from these sales were approximately $616 million, and we recognized an extraordinary gain of $89 million, net of income taxes of $60 million.

**3. Merger-Related Costs and Asset Impairments**

During the quarter and nine months ended September 30, we incurred merger-related costs associated with our merger with Coastal and asset impairments as follows:

| | Quarter Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2001 | 2000 | 2001 | 2000 |
| | (In millions) | | | |
| Merger-related costs | $32 | $ 3 | $1,687 | $56 |
| Asset impairments | — | — | 107 | — |
| | $32 | $ 3 | $1,794 | $56 |

*Merger-Related Costs*

Our merger-related costs consisted of the following:

| | Quarter Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2001 | 2000 | 2001 | 2000 |
| | (In millions) | | | |
| Employee severance, retention and transition costs | $10 | $— | $ 831 | $— |
| Transaction costs | 3 | 3 | 70 | 56 |
| Business and operational integration costs | — | — | 416 | — |
| Merger-related asset impairments | 5 | — | 157 | — |
| Other | 14 | — | 213 | — |
| | $32 | $ 3 | $1,687 | $56 |

Employee severance, retention and transition costs include direct payments to, and benefit costs for, severed employees and early retirees that occurred as a result of our merger-related workforce reduction and consolidation. Following the Coastal merger, we completed an employee restructuring across all of our operating segments, resulting in the reduction of 3,285 full-time positions through a combination of early retirements and terminations. Employee severance costs include actual severance payments and costs for pension and post-retirement benefits settled and curtailed under existing benefit plans as a result of this restructuring. Retention charges include payments to employees who were retained following the merger and payments to employees to satisfy contractual obligations. Transition costs relate to costs to relocate employees and costs for severed and retired employees arising after their severance date to transition their jobs into the ongoing workforce. Substantially all of the costs accrued in connection with these activities had been paid as of September 30, 2001.

Also included in employee severance, retention and transition costs for the nine months ended September 30, 2001, 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.

Business and operational integration costs include charges to consolidate facilities and operations of our business segments, such as lease termination and abandonment charges, recognition of the mark-to-market value of energy trading contracts resulting from changes in how these contracts are managed under our combined operating strategy and incremental fees under software and seismic license agreements. Included in these charges are approximately $242 million in estimated lease-related costs to relocate our pipeline operations from Detroit, Michigan to Houston, Texas and from El Paso, Texas to Colorado Springs, Colorado. These charges were estimated in the second quarter of 2001 at the time we completed our relocations. Future developments, such as sub-leases of our vacated space or other events, could impact our estimates, and these changes could be material to the amounts we originally recorded.

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 in our Merchant Energy, Production and Pipelines segments, and all of these assets have either been abandoned or continue to be held for use.

Other costs include payments made in satisfaction of obligations arising from the FTC approval of the merger and other miscellaneous charges.

*Asset Impairments*

During the nine months ended September 30, 2001, we incurred other asset impairment charges of $107 million. These charges consisted of a $60 million write-down of a non-strategic communications company in Brazil in our corporate and other segment and charges of $47 million primarily related to Merchant Energy's impairment of its East Asia Power investment in the Philippines. These write-downs were a result of weak economic conditions causing a permanent decline in the value of these investments. We continue to hold all of these investments.

**4. Changes in Accounting Estimates**

Included in our operation and maintenance costs for the quarter and nine months ended September 30, 2001, were approximately $113 million and $317 million in costs related to changes in our estimates of environmental remediation liabilities, legal obligations and the usability of spare parts inventory in our worldwide operations. These changes arose as a result of an ongoing evaluation of our operating standards, strategies and plans following our merger with Coastal. The evaluation related specifically to the sale of our retail gas stations and the shutdown of our Kansas refining operations, a fire at our Aruba refinery, the lease of our Corpus Christi refinery and the rupture of a transmission line near Carlsbad, New Mexico in August of 2000. These changes in estimates reduced net income before extraordinary items and net income for the quarter and nine months ended September 30, 2001 by approximately $76 million and $215 million.

**5. Ceiling Test Charge**

Under the full cost method of accounting for natural gas and oil properties, we perform quarterly ceiling tests to evaluate whether the carrying value of natural gas and oil properties exceeds the present value of future net revenues, discounted at 10 percent, plus the lower of cost or fair market value of unproved properties. At September 30, 2001, capitalized costs exceeded this ceiling limit by $135 million, including $87 million for our Canadian full cost pool, $28 million for our Brazilian full cost pool and $20 million for other international production operations, primarily in Turkey. These charges are based on the November 1, 2001, daily posted oil and natural gas sales prices, adjusted for oilfield or gas gathering hub and wellhead price differences as appropriate. As described in Note 1, we use financial instruments (which qualify as hedges under the provisions of SFAS No. 133) to hedge against volatility of natural gas and oil prices, and we included the impact of our hedging program in our full cost ceiling test calculations. Had we not included this impact, our charge would not have materially changed since we do not significantly hedge our international production activities. These non-cash write-downs are included as ceiling test charges in our income statement.

Had we computed the non-cash ceiling test charges based on the daily oil and natural gas prices as of September 30, 2001, the charges would have been approximately $275 million, including approximately $227 million for our Canadian full cost pool and $48 million for our Brazilian and other international production operations. Our determination of these charges includes the impact on future cash flows of our hedging program. Had the impact of our hedging program been excluded, the charges would have been approximately the same for our international production operations, but we would have incurred an additional charge of approximately $576 million related to our domestic full cost pool.

## 6. Earnings Per Share

Our computation of basic and diluted earnings per common share for the periods ended September 30 is presented below:

| | Quarter Ended September 30, | | | |
|---|---|---|---|---|
| | 2001 | | 2000 | |
| | Basic | Diluted | Basic | Diluted |
| | (In millions, except per common share amounts) | | | |
| Income before extraordinary items | $ 216 | $ 216 | $ 282 | $ 282 |
| Interest on trust preferred securities and preferred stock dividends, net of income taxes | — | 3 | — | 3 |
| Adjusted income before extraordinary items | 216 | 219 | 282 | 285 |
| Extraordinary items, net of income taxes | (5) | (5) | — | — |
| Adjusted net income | $ 211 | $ 214 | $ 282 | $ 285 |
| Average common shares outstanding | 506 | 506 | 495 | 495 |
| Effect of dilutive securities | | | | |
| Stock options | — | 3 | — | 9 |
| Preferred stock | — | — | — | 1 |
| FELINE PRIDES$^{SM}$ | — | 3 | — | 4 |
| Trust preferred securities | — | 8 | — | 8 |
| Average common shares outstanding[a] | 506 | 520 | 495 | 517 |
| Earnings per common share | | | | |
| Adjusted income before extraordinary items | $ 0.43 | $ 0.42 | $0.57 | $0.55 |
| Extraordinary items, net of income taxes | (0.01) | (0.01) | — | — |
| Adjusted net income | $ 0.42 | $ 0.41 | $0.57 | $0.55 |

[a] Diluted average common shares outstanding for the quarter ended September 30, 2001, excludes the antidilutive effect of 8 million shares related to convertible debentures issued in 2001.

| | Nine Months Ended September 30, | | |
|---|---|---|---|
| | 2001 | 2000 | |
| | Basic[a] | Basic | Diluted |
| | (In millions, except per common share amounts) | | |
| Income (loss) before extraordinary items | $ (308) | $ 882 | $ 882 |
| Interest on trust preferred securities and preferred stock dividends, net of income taxes | — | — | 8 |
| Adjusted income (loss) before extraordinary items | (308) | 882 | 890 |
| Extraordinary items, net of income taxes | 26 | 89 | 89 |
| Adjusted net income (loss) | $ (282) | $ 971 | $ 979 |
| Average common shares outstanding | 504 | 493 | 493 |
| Effect of dilutive securities | | | |
| Stock options | — | — | 7 |
| Preferred stock | — | — | 1 |
| FELINE PRIDES$^{SM}$ | — | — | 2 |
| Trust preferred securities | — | — | 8 |
| Average common shares outstanding | 504 | 493 | 511 |
| Earnings (loss) per common share | | | |
| Adjusted income (loss) before extraordinary items | $(0.61) | $1.79 | $1.74 |
| Extraordinary items, net of income taxes | 0.05 | 0.18 | 0.18 |
| Adjusted net income (loss) | $(0.56) | $1.97 | $1.92 |

[a] 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.

## 7. Accounting for Hedging Activities

On January 1, 2001, we adopted the provisions of SFAS No. 133 and recorded a cumulative-effect adjustment of $1,280 million, net of income taxes, in accumulated other comprehensive income to recognize the fair value of all derivatives designated as hedging instruments. The majority of the initial charge related to hedging cash flows from anticipated sales of natural gas for 2001 and 2002. During the quarter and nine months ended September 30, 2001, $149 million and $931 million, net of income taxes, of this initial transition adjustment was reclassified to earnings as a result of hedged sales and purchases during the periods, and an additional $130 million of this adjustment is expected to 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 and nine months ended September 30, 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. 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 September 30, 2001, the value of cash flow hedges included in accumulated other comprehensive income was an unrealized gain of $430 million, net of income taxes. Of this amount, we estimate that $417 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 also includes our proportionate share of amounts recorded in other comprehensive income by our unconsolidated affiliates who use derivatives as cash flow hedges.

For the quarter and nine months ended September 30, 2001, we recognized net losses of $4 million and net gains of $9 million, net of income taxes, related to the ineffective portion of all 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. dollar. During the nine months ended September 30, 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 10 for further information.

## 8. Property, Plant and Equipment

In June 2001, we entered into a 20-year lease agreement related to our Corpus Christi refinery and related assets with Valero Energy Corporation. Under the lease, Valero pays us a quarterly amount that escalates after the second year of the lease. In addition, Valero has the option to purchase the plant and related assets at the end of the second year of the lease for approximately $294 million, and a similar option each year thereafter at an annually increasing amount. Based on its terms, the lease qualified as an operating lease. Future minimum lease payments total $811 million: $14 million in 2001; $19 million in 2002; $37 million in 2003; $43 million in 2004 and 2005; and a total of $655 million thereafter.

## 9. Inventory

Our inventory consisted of the following:

| | September 30, 2001 | December 31, 2000 |
|---|---|---|
| | (In millions) | |
| Refined products, crude oil and chemicals | $692 | $1,004 |
| Coal, materials and supplies and other | 258 | 273 |
| Natural gas in storage | 30 | 93 |
| Total | $980 | $1,370 |

## 10. Debt and Other Credit Facilities

At September 30, 2001, our weighted average interest rate on short-term borrowings was 3.6%, and at December 31, 2000, it was 7.4%. We had the following short-term borrowings, including current maturities of long-term debt:

| | September 30, 2001 | December 31, 2000 |
|---|---|---|
| | (In millions) | |
| Commercial paper | $1,359 | $1,416 |
| Current maturities of long-term debt | 1,111 | 1,179 |
| Notes payable to unconsolidated affiliates | 103 | 396 |
| Short-term credit facility | — | 455 |
| Notes payable | — | 343 |
| Other credit facilities | 200 | 10 |
| | $2,773 | $3,799 |

*Acquisition of PG&E's Texas Midstream Operations*

In connection with our acquisition of PG&E's Texas Midstream operations in December 2000, we assumed $527 million in debt. We also established a $700 million short-term credit facility for use in connection with this acquisition, under which $455 million was borrowed as of December 31, 2000. In February 2001, we borrowed the balance of this facility and redeemed $293 million of debt assumed from PG&E. In two payments occurring in March and June 2001, we repaid the outstanding balance of the credit facility, and the facility was terminated. In addition, as of September 30, 2001, we retired an additional $48 million of debt assumed from PG&E.

*Revolving Credit Facilities*

In January 2001, Coastal terminated approximately $1.5 billion in revolving credit facilities and became a designated borrower under our 364-day and our 3-year revolving credit and competitive advance facilities. In June 2001, we replaced our 364-day revolving credit facility with a renewable $3 billion, 364-day revolving credit and competitive advance facility. El Paso Natural Gas Company (EPNG) and Tennessee Gas Pipeline Company (TGP) are designated borrowers under the new facility. Coastal, EPNG, and TGP remain designated borrowers under our 3-year facility. The interest rate on these facilities varies and was based on the London Interbank Offered Rate (LIBOR) plus 50 basis points at September 30, 2001. No amounts were outstanding under these facilities at September 30, 2001.

*Other*

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.

In April 2001, we filed a shelf registration with the Securities and Exchange Commission to sell, from time to time, up to a total of $3 billion in debt securities, preferred and common stock, medium term notes, or trust securities.

In May 2001, we issued $500 million aggregate principal amount 7.00% notes due 2011. Proceeds of approximately $496 million, net of issuance costs, were used to repay short-term indebtedness and for general corporate purposes. Also in May 2001, we retired $100 million aggregate principal amount 9.0% notes.

In July 2001, we issued $700 million aggregate principal amount 7.80% medium term notes due 2031. Net proceeds of approximately $688 million, net of issuance costs, were used to repay our short-term borrowings and for general corporate purposes. Also in July 2001, we retired $600 million aggregate principal amount 6.625% notes and $100 million aggregate principal amount floating rate notes.

In addition to the items discussed above, during the nine months ended September 30, 2001, we issued $100 million of long-term debt and retired long-term debt with the aggregate principal amount of approximately $175 million.

In October 2001, we borrowed approximately $238 million under a loan agreement. The interest rate on the loan varies based on LIBOR plus 1.425%, and the loan matures in 2004. The loan is collateralized by the lease payments from Valero for our Corpus Christi refinery and related assets. The net proceeds from the loan were used to repay short-term indebtedness and for general corporate purposes.

In November 2001, we and a third party financial investor formed a series of companies that we refer to as Gemstone. Through Gemstone, we received approximately $762 million in cash through the issuance of a combination of debt securities and preferred securities of one of our consolidated subsidiaries, the proceeds from which were used to acquire an interest in electric generation assets in Brazil and for general corporate purposes. The debt securities are payable on demand and carry a fixed annual interest rate of 5.25%. The preferred securities of our subsidiary entitle the investor to a preferred return of 8.03%. For a further discussion of Gemstone, see Note 13.

**11. Commitments and Contingencies**

*Legal Proceedings*

We and several of our subsidiaries were named defendants in nine purported class action or citizen lawsuits and one shareholder lawsuit filed in California state courts (a list of the *California* cases is included in Part II, Item 1, Legal Proceedings). The class action cases contend generally that our entities acted alone or in combination with other unrelated companies to limit the construction of new pipeline capacity to California or to manipulate the price of natural gas sold into the California marketplace. The shareholder suit contends that we, through our directors, failed to prevent the conduct alleged in these underlying cases. We removed each of these cases to federal court and requested that they be consolidated for all pretrial activities. Eight of the nine suits were consolidated in the U.S. District Court in Nevada. On October 25, 2001, the Nevada court remanded these cases to the California State court system for all further proceedings.

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

On August 19, 2000, a main transmission line owned and operated by EPNG ruptured at the crossing of the Pecos River near Carlsbad, New Mexico. Twelve individuals at the site were fatally injured. 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, Legal Proceedings). Through September 30, 2001, we had settled all claims in the *Heady* cases, the *Jennifer Smith* case and the *Green* case. Payments for the claimants in the settled cases 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 addition, on June 20, 2001, the U.S. Department of Transportation's Office of Pipeline Safety issued a Notice of Proposed Violation to EPNG. The Notice alleged five probable violations of its regulations (a list of the alleged five probable violations is included in Part II, Item 1, Legal Proceedings), proposed fines totaling $2.5 million and proposed corrective actions. On October 15, 2001, EPNG filed a detailed response with the Office of Pipeline Safety disputing each of the alleged violations.

In May 1999, one of our subsidiaries was named as a defendant in a suit filed in the 319th Judicial District Court, Nueces County, Texas by an individual employed by one of our contractors (*Rolando Lopez and Rosanna Barton v. Coastal Refining & Marketing, Inc. and The Coastal Corporation*). The suit sought damages for injuries sustained at the time of an explosion at one of our refining plants, and was settled in August 2000 for a total payment of $7 million, of which $5 million was covered by insurance. Three of the refinery employees intervened in the suit and sought damages for injuries sustained in the explosion. Those claims were tried in August 2000, resulting in a $122 million verdict, for which there is insurance coverage. The case has been appealed to the Thirteenth Court of Appeals of Texas, and all appellate briefing in that court has been completed.

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. Plaintiffs, defendants and most of the third-party defendants, including our current and former affiliates, have reached a settlement reflected in a consent decree lodged in the district court on September 20, 2001. If the consent decree is approved by the court, the plaintiffs will be reimbursed $120 million plus interest since June 2001, and the defendants and settling third-party defendants will receive releases and contribution protection. The settlement will not have a material adverse effect on our financial position, operating results or cash flows. The remaining contribution claims by the defendants against the non-settlement third-party defendants are scheduled for trial in late 2001.

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). 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 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 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 and received water discharge permits from the agency for its Kentucky compressor stations. The relevant Kentucky compressor stations are being characterized and remediated under a 1994 consent order with the Environmental Protection Agency (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, based on information known to date, we do not expect the ultimate resolution of these matters to have a material adverse effect on our ongoing 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 September 30, 2001, we had a reserve of approximately $524 million for expected remediation costs. In addition, we expect to make capital expenditures for environmental matters of approximately $300 million in the aggregate for the years 2001 through 2006. These expenditures primarily relate to compliance with clean 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 been granted an administrative hearing on 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 with the Federal Energy Regulatory Commission (FERC) that established a mechanism for recovering a substantial portion of the environmental costs identified in its internal project. The stipulation and agreement was effective July 1, 1995, and most of the amounts have 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 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 56 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 September 30, 2001, we have estimated our share of the remediation costs at these sites to be between approximately $63 million and $199 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.

In Michigan, the Michigan Environmental Response Act requires individuals, including corporations, who have caused contamination to remediate the contamination to regulatory standards. Owners or operators of contaminated property who did not cause the contamination are not required to remediate the contamination, but must exercise due care in their use of the property so that the contamination is not exacerbated and the property does not pose a threat to human health. We estimate that the costs to comply with the Michigan regulations will be approximately $21 million, which will be expended over a period of several years and for which appropriate reserves have been made.

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 approximately 1.2 billion cubic feet per day of California capacity to El Paso Merchant Energy was anticompetitive and an abuse of the affiliate relationship under FERC's policies. Other parties in the proceeding requested that the original complaint be set for hearing and that Merchant Energy pay back any profits it has earned under the contract. In March 2001, FERC established a hearing, before an administrative law judge, to address the issue of whether EPNG and/or Merchant Energy had market power and, if so, had exercised it. The hearing on the anticompetitive issue concluded in May 2001. In June 2001, FERC issued an order granting the request of the CPUC and others to allow the administrative law judge to take evidence on the affiliate abuse issue. In October 2001, a FERC administrative law judge issued a proposed decision finding that El Paso did not exercise market power and that the market power portion of the CPUC's complaint should be dismissed. The decision further found that El Paso had violated FERC's marketing affiliate regulations. The judge's proposed decision will be briefed to, and will be effective only if approved by, the FERC. On October 30, 2001, the Market Oversight and Enforcement section of the FERC's office of the General Counsel filed comments in this proceeding stating that record development at the trial was inadequate to conclude that EPNG and Merchant Energy complied with FERC's regulation. We have filed a response to this complaint.

Two groups of EPNG's customers, those within California and those east of California, have recently filed complaints against EPNG with FERC. In July 2001, twelve parties composed of California customers, natural gas producers and natural gas marketers, filed a complaint alleging that EPNG's full requirements contracts with its east of California customers should be converted to contracts with specific volumetric entitlements, that EPNG should be required to expand its interstate pipeline system and that firm shippers who experience reductions in their nominated gas volumes should be awarded demand charge credits. EPNG filed its response to this complaint on August 2, 2001. Also, in July 2001, ten parties, most of which are east of California full-requirement contract customers, filed a complaint against EPNG with FERC, alleging that EPNG violated the Natural Gas Act of 1938 and breached its contractual obligations by failing to expand its system in order to serve the needs of the full-requirement contract shippers. The complainants have requested that FERC require EPNG to show cause why it should not be required to augment its system capacity. EPNG filed its response to this complaint on August 6, 2001, and requested that both groups' complaints be consolidated for future proceedings. On September 10, 2001, the latter complainants filed a motion for partial summary disposition of their complaint, to which EPNG responded on September 25, 2001.

In June 2001, the Western Australia regulators issued a draft rate decision at lower than expected levels for the Dampier-to-Bunbury pipeline owned by EPIC Energy Australia Trust, in which we have a 33 percent ownership interest and a total investment, including financial guarantees, of approximately $180 million. EPIC Energy Australia has appealed a variety of issues related to the draft decision to the Western Australia Supreme Court. The decision from the court is expected later this year. If the draft decision rates are implemented, the new rates will adversely impact future operating results, liquidity, and debt capacity, possibly reducing the value of our investment by up to $120 million.

In September 2001, 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 FERC, would dictate how all our energy affiliates conduct business and interact with our interstate pipelines. We cannot predict the outcome of the NOPR, but adoption of the regulations in substantially the form proposed would, at a minimum, place additional administrative and operational burdens on us.

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

*Other*

In May 2001, we entered into an operating lease for the Lakeside Technology Center, a telecommunications carrier hotel located in Chicago, Illinois. The lease term expires in 2006, at which time we have an option to buy the facility for approximately $275 million. If we do not purchase the facility at the end of the lease term, we have an obligation to pay a residual guaranty amount up to approximately 86 percent of the purchase option price. Payments under the lease are indexed to the lessor's financing costs and are subject to change as a result of changes in the 3 month LIBOR. Based on LIBOR at September 30, 2001, aggregate estimated minimum lease payments totaled $50 million; $7 million in 2001; $10 million in 2002 through 2005; and $3 million thereafter. For the quarter and nine months ended September 30, 2001, we recorded rental expense of $3 million and $5 million for this lease.

From May to October 2001, we entered into agreements to time charter four separate ships to secure transportation for our developing liquified natural gas business. The agreements provide for deliveries of vessels between 2003 to 2005. Each time charter has a 20-year term commencing when the vessels are delivered with the possibility of two 5-year extensions. We have options to charter up to 4 additional ships. The options expire beginning in November 2001 and we currently do not intend to exercise these options.

Our foreign investments are subject to risks and unforeseen obstacles that, in many cases may be beyond our control or ability to manage. We attempt to manage or mitigate these risks through our due diligence and partner selection processes, through the denomination of foreign transactions, where possible, in U.S. Dollars, and by maintaining insurance coverage, whenever obtainable. We currently have three power plants in Pakistan, with a total investment, including financial guarantees on these projects, of approximately $276 million. While we are aware of no specific threats or actions against these investments, events in that region, including possible retaliation for American military actions, could impact these projects and our related investments. At this time, we believe that through a combination of commercial insurance, political insurance and rights under contractual obligations, our financial exposure in Pakistan from acts of war, hostility, terrorism or political instability is not material. It is possible, however, that new information, future developments in the region, or the inability of a party or parties to fulfill their contractual obligations could cause us to reassess our potential exposure. We also have investments in oil and natural gas, power and pipeline projects in Argentina with an aggregate investment, including financial guarantees, of approximately $384 million. The general decline of economic conditions in Argentina led by the possible government default on public debt obligations is causing a significant drop in demand for power on the spot market. We believe that the current economic difficulties in Argentina will not have a material adverse effect on our financial position, results of operations or cash flows. However, we will continue to monitor the economic situation and it is possible that future developments in Argentina could cause us to reassess our exposure.

*Guarantees*

At September 30, 2001, we had guarantees totaling $4.3 billion in connection with our international project development activities and various other projects, operating leases and letters of credit, including approximately $1 billion associated with our investments in unconsolidated affiliates and minority interests.

## 12. Segment Information

We segregate our business activities into four distinct operating segments: Pipelines, Merchant Energy, Production and Field Services. These segments are strategic business units that provide a variety of energy products and services. They are managed separately as each business unit requires different technology and marketing strategies. We measure segment performance using earnings before interest expense and income taxes (EBIT). The following are our results as of and for the periods ended September 30:

| | Quarter Ended September 30, 2001 | | | | | |
|---|---|---|---|---|---|---|
| | Pipelines | Merchant Energy | Production | Field Services | Other[(1)] | Total |
| | (In millions) | | | | | |
| Revenues from external customers | $ 531 | $13,003 | $ — | $ 308 | $ 3 | $13,845 |
| Intersegment revenues | 78 | (47) | 587 | 251 | (869) | — |
| Merger-related costs and asset impairments | 1 | (1) | — | 8 | 24 | 32 |
| Ceiling test charges | — | — | 135 | — | — | 135 |
| Operating income (loss) | 237 | 148 | 168 | 30 | (103) | 480 |
| EBIT | 274 | 255 | 169 | 43 | (93) | 648 |
| Segment assets | 14,228 | 16,844 | 8,566 | 3,829 | 3,651 | 47,118 |

| | Quarter Ended September 30, 2000 | | | | | |
|---|---|---|---|---|---|---|
| | Pipelines | Merchant Energy | Production | Field Services | Other[(1)] | Total |
| | (In millions) | | | | | |
| Revenues from external customers | $ 576 | $11,830 | $ 352 | $ 401 | $ 309 | $13,468 |
| Intersegment revenues | 61 | 94 | 45 | 43 | (243) | — |
| Merger-related costs and asset impairments | — | — | — | — | 3 | 3 |
| Operating income (loss) | 247 | 144 | 157 | 44 | (20) | 572 |
| EBIT | 297 | 251 | 149 | 58 | (11) | 744 |
| Segment assets | 13,946 | 14,605 | 5,572 | 2,154 | 2,562 | 38,839 |

| | Nine Months Ended September 30, 2001 | | | | | |
|---|---|---|---|---|---|---|
| | Pipelines | Merchant Energy | Production | Field Services | Other[(1)] | Total |
| | (In millions) | | | | | |
| Revenues from external customers | $ 1,813 | $41,407 | $ 153 | $1,577 | $ 374 | $45,324 |
| Intersegment revenues | 240 | 583 | 1,560 | 476 | (2,859) | — |
| Merger-related costs and asset impairments | 316 | 193 | 63 | 46 | 1,176 | 1,794 |
| Ceiling test charges | — | — | 135 | — | — | 135 |
| Operating income (loss) | 562 | 331 | 642 | 90 | (1,404) | 221 |
| EBIT | 676 | 647 | 643 | 134 | (1,370) | 730 |
| Segment assets | 14,228 | 16,844 | 8,566 | 3,829 | 3,651 | 47,118 |

| | Nine Months Ended September 30, 2000 | | | | | |
|---|---|---|---|---|---|---|
| | Pipelines | Merchant Energy | Production | Field Services | Other[(1)] | Total |
| | (In millions) | | | | | |
| Revenues from external customers | $ 1,845 | $27,998 | $ 950 | $ 899 | $ 888 | $32,580 |
| Intersegment revenues | 156 | 250 | 235 | 94 | (735) | — |
| Merger-related costs and asset impairments | — | — | — | — | 56 | 56 |
| Operating income (loss) | 856 | 354 | 488 | 126 | (108) | 1,716 |
| EBIT | 982 | 648 | 472 | 166 | (75) | 2,193 |
| Segment assets | 13,946 | 14,605 | 5,572 | 2,154 | 2,562 | 38,839 |

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

## 13. 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 September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2001 | 2000 | 2001 | 2000 |
| | (In millions) | | | |
| Operating results data | | | | |
| Revenues and other income | $ 586 | $ 2,971 | $ 2,030 | $ 6,759 |
| Costs and expenses | (469) | (2,832) | (1,675) | (6,416) |
| Income from continuing operations | 117 | 139 | 355 | 343 |
| Net income | 102 | 127 | 302 | 297 |

*Gemstone*

In November 2001, we and a third party financial investor formed a series of companies that we refer to as Gemstone. Into Gemstone, the third party contributed $50 million in cash and an additional $950 million was raised through a note issuance to other third parties. These funds were used to acquire a Brazilian power investment, a $300 million minority interest in one of our consolidated subsidiaries and $462 million of our debt securities. We contributed $280 million in cash as well as several Brazilian investments with a total value of $274 million in exchange for our interest in Gemstone. The third party investor is entitled to a preferred return on its minority interest in our subsidiary and the debt securities we issued are payable on demand and carry a fixed annual interest rate.

Our total investment in Gemstone is $554 million, and we will account for our investment using the equity method of accounting since we do not have the ability to exercise control over the entity. We will account for the investor's preferred interest in our consolidated subsidiary as minority interest in our balance sheet and will account for the preferred return as minority interest in our income statement. The debt securities we issued will be included in short-term borrowings in our balance sheet, with the related interest as interest expense in our income statement.

As additional credit support, we issued mandatorily convertible preferred stock with an aggregate liquidation preference of $950 million to a share trust we control. Upon the occurrence of negative events, including a substantial decline in our stock price coupled with significant downgrades in our credit ratings, we could be required to remarket our preferred stock on terms that are designed to generate a sufficient amount of cash to repay Gemstone's noteholders.

## 14. New Accounting Pronouncements Not Yet Adopted

*Business Combinations*

In July 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 141, *Business Combinations*. This statement requires that all transactions that fit the definition of a business combination be accounted for using the purchase method and prohibits the use of the pooling of interests method for all business combinations initiated after June 30, 2001. This statement also establishes specific criteria for the recognition of intangible assets separately from goodwill and requires unallocated negative goodwill to be written off immediately as an extraordinary item. This standard will have an impact on any business combination we undertake in the future. We are currently evaluating the effects of this pronouncement on our historical financial statements.

*Goodwill and Other Intangible Assets*

In July 2001, the FASB issued SFAS No. 142, *Goodwill and Other Intangible Assets*. This statement requires that goodwill no longer be amortized but intermittently tested for impairment at least on an annual basis. Other intangible assets are to be amortized over their useful life and reviewed for impairment in accordance with the provisions of SFAS No. 121, *Accounting for the Impairment of Long-Lived Assets and Long-Lived Assets to be Disposed of*. An intangible asset with an indefinite useful life can no longer be amortized until its useful life becomes determinable. This statement has various effective dates, the most significant of which is January 1, 2002. We are currently evaluating the effects of this pronouncement.

*Accounting for Asset Retirement Obligations*

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

*Accounting for the Impairment or Disposal of Long-Lived Assets*

In October 2001, the FASB issued SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. This statement requires that long-lived assets that are to be disposed of by sale be measured at the lower of book value or fair value less cost to sell. The standard also expanded the scope of discontinued operations to include all components of an entity with operations that can be distinguished from the rest of the entity and that will be eliminated from the ongoing operations of the entity in a disposal transaction. The provisions of this statement are effective for fiscal years beginning after December 15, 2001. We are currently evaluating the effects of this pronouncement.

*Derivatives Implementation Group Issue C-16*

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

## 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 amended Current Report on Form 8-K/A filed May 17, 2001, in addition to the financial statements and notes presented in Item 1, Financial Statements, 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 discussion and analysis of our financial condition and results of operations reflects the combined information of our two companies for all periods presented.

*Merger-Related Costs, Asset Impairments and Other Charges*

During the quarters and nine months ended September 30, 2001 and 2000, we incurred charges that had a significant impact on our results of operations, financial position and cash flows, and that are not expected to continue as follows:

| | Quarter Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2001 | 2000 | 2001 | 2000 |
| | (In millions) | | | |
| Merger-related costs | $ 32 | $3 | $1,687 | $56 |
| Asset impairments | — | — | 107 | — |
| Total merger-related costs and asset impairments | 32 | 3 | 1,794 | 56 |
| Changes in estimates | 113 | — | 317 | — |
| | 145 | 3 | 2,111 | 56 |
| Ceiling test charges | 135 | — | 135 | — |
| | $280 | $3 | $2,246 | $56 |

(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
Bbl = barrel
BBtu = billion British thermal units
BBtue = billion British thermal unit equivalents
Btu = British thermal unit
MBbls = thousand barrels
MMBtu = million British thermal units
Mcf = thousand cubic feet
MMcf = million cubic feet
MTons = thousand tons
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.

Merger-related costs include employee severance, retention and transition charges; write-offs and write-downs of assets; charges to relocate assets and employees and consolidate operations; contract termination charges; and other charges related to our merger with Coastal. Although we expect to incur additional merger-related charges during the fourth quarter of 2001, we expect the level of those charges to be significantly less than those levels incurred in the first nine months of 2001.

Asset impairments include non-merger related write-downs of our investments in an international power project, as well as corporate-owned, private equity investments. These write-downs were a result of weak economic conditions causing a permanent decline in the value of these investments.

Changes in estimates consist of changes in our estimated environmental remediation liabilities, legal obligations and the usability of spare parts inventories in our operations. These charges were necessitated by an ongoing evaluation of our operating standards, strategies and plans following the Coastal merger.

The ceiling test charge resulted from the write-downs of the carrying value of natural gas and oil properties associated with our international production operations.

Each of these charges is discussed more fully in Item 1, Financial Statements, Notes 3, 4 and 5. By segment, these charges were recorded as follows:

| | Quarter Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2001 | 2000 | 2001 | 2000 |
| | (In millions) | | | |
| Pipelines | $ (1) | $— | $ 334 | $— |
| Merchant Energy | 61 | — | 328 | — |
| Production | 138 | — | 208 | — |
| Field Services | 17 | — | 56 | — |
| Segment total | 215 | — | 926 | — |
| Corporate and other | 65 | 3 | 1,320 | 56 |
| Consolidated total | $280 | $ 3 | $2,246 | $56 |

## Results of Operations

For the quarter ended September 30, 2001, we had net income of $211 million versus $282 million for the quarter ended September 30, 2000. The 2001 results included the charges discussed above totaling $280 million, or $189 million after taxes. We also recorded net extraordinary losses totaling $5 million, net of income taxes, as a result of additional income tax accruals associated with FTC ordered sales which occurred during the first and second quarters of 2001. During the third quarter of 2000, merger-related costs were $3 million, or $2 million net of income taxes. Net income, excluding the effects of these charges and extraordinary items, would have been $405 million in 2001 versus $284 million in 2000, or an increase of 43 percent.

For the nine months ended September 30, 2001, we had net loss of $282 million versus net income of $971 million for the nine months ended September 30, 2000. The 2001 loss was a result of the charges discussed above which totaled $2,246 million, or $1,626 million after taxes. We also recorded net extraordinary gains totaling $26 million, net of income taxes, as a result of FTC ordered sales of our Gulfstream pipeline project and Midwestern Gas Transmission system and our investments in the Empire State, Stingray, U-T Offshore and Iroquois pipeline systems. For the nine months ended September 30, 2000, merger-related charges were $56 million, or $38 million net of income taxes, and we recorded extraordinary 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 after-tax effects of these charges and extraordinary items, would have been $1,318 million in 2001 versus $920 million in 2000, or an increase of 43 percent.

For the quarter ended September 30, 2001, our EBIT was $648 million in 2001 versus $744 million in 2000. Excluding merger-related costs, asset impairments, other charges and ceiling test charges mentioned above, EBIT would have been $928 million in 2001 versus $747 million in 2000, or an increase of 24 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 Pipelines segment contributing 37 percent of the total.

For the nine months ended September 30, 2001, EBIT was $730 million in 2001 versus $2,193 million in 2000. Excluding merger-related costs, asset impairments, other charges and ceiling test charges, EBIT would have been $2,976 million in 2001 versus $2,249 million in 2000, or an increase of 32 percent. EBIT from the non-regulated segments of our business, which included our Merchant Energy, Production and Field Services segments, totaled 68 percent of all operating segments, with our Pipelines segment contributing 32 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 products sold) provides a more accurate and meaningful basis for analyzing operating results for the trading and refining portions of Merchant Energy and the Field Services segment. For a further discussion of our individual segments, see Item 1, Financial Statements, Note 12. The segment results presented below include the charges discussed under "Recent Developments" above:

| | Quarter Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2001 | 2000 | 2001 | 2000 |
| | (In millions) | | | |
| **Earnings Before Interest Expense and Income Taxes** | | | | |
| Pipelines | $274 | $297 | $ 676 | $ 982 |
| Merchant Energy | 255 | 251 | 647 | 648 |
| Production | 169 | 149 | 643 | 472 |
| Field Services | 43 | 58 | 134 | 166 |
| Segment total | 741 | 755 | 2,100 | 2,268 |
| Corporate and other, net | (93) | (11) | (1,370) | (75) |
| Consolidated EBIT | $648 | $744 | $ 730 | $2,193 |

**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 reservation 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 periods ended September 30:

| | Quarter Ended | | Nine Months Ended | |
|---|---|---|---|---|
| | 2001 | 2000 | 2001 | 2000 |
| | (In millions, except volume amounts) | | | |
| Operating revenues | $ 609 | $ 637 | $ 2,053 | $ 2,001 |
| Operating expenses | (372) | (390) | (1,491) | (1,145) |
| Other income | 37 | 50 | 114 | 126 |
| EBIT | $ 274 | $ 297 | $ 676 | $ 982 |
| Throughput volumes (BBtu/d)[(1)] | | | | |
| TGP | 4,162 | 4,023 | 4,431 | 4,243 |
| EPNG | 4,550 | 4,617 | 4,641 | 4,184 |
| ANR | 3,655 | 3,606 | 3,831 | 3,791 |
| CIG | 2,136 | 1,963 | 2,282 | 2,016 |
| SNG | 1,692 | 1,848 | 1,858 | 2,105 |
| Equity investments (our proportional share) | 2,341 | 2,027 | 2,160 | 2,082 |
| Total throughput | 18,536 | 18,084 | 19,203 | 18,421 |

(1) Throughput volumes exclude those related to pipeline systems sold in connection with our Coastal and Sonat mergers including the Midwestern Gas Transmission, East Tennessee Natural Gas and Sea Robin systems; the Empire State, Iroquois and Destin pipeline investments.

*Third Quarter 2001 Compared to Third Quarter 2000*

Operating revenues for the quarter ended September 30, 2001, were $28 million lower than the same period in 2000. The decrease was primarily due to contract remarketing on the TGP system during 2000 and lower sales of excess natural gas in 2001 on several of our pipeline systems due to lower volumes and lower natural gas prices. Also contributing to the decrease were the sales of the Midwestern Gas Transmission system in April 2001 and Crystal Gas Storage, Inc. in September 2000, lower realized prices on the sales of natural gas purchased from the Dakota gasification facility in 2001 and lower remarketing rates on released capacity in 2001 as a result of SNG's 2000 rate case settlement allowing customers to partially reduce their firm transportation capacity. Partially offsetting the decrease were higher reservation 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 and the impact of completed system expansions and new storage and transportation contracts on the ANR and CIG systems during 2001.

Operating expenses for the quarter ended September 30, 2001, were $18 million lower than the same period in 2000. The decrease was due to accruals for the replacement of system balancing gas on ANR in 2000, lower corporate allocations and operating and maintenance expenses due to cost efficiencies following the merger with Coastal and the impact of lower prices on natural gas purchased from the Dakota gasification facility in 2001. Also contributing to the decrease was reduced depreciation expenses due to the sales of Midwestern Gas Transmission system and Crystal Gas Storage.

Other income for the quarter ended September 30, 2001, was $13 million lower than the same period due to higher 2000 equity earnings on Citrus Corp. as a result of a one-time benefit recorded in 2000 and the sale of non-pipeline assets in 2000.

*Nine Months Ended 2001 Compared to Nine Months Ended 2000*

Operating revenues for the nine months ended September 30, 2001, were $52 million higher than the same period in 2000. The increase was due to higher reservation 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 and the impact of completed system expansions and new storage and transportation contracts on ANR and CIG during 2001. Also contributing to the increase were the impact of higher natural gas prices in the first and second quarters on sales of segment-owned production, sales of excess natural gas and sales under regulated natural gas sales contracts as well as higher throughput from increased deliveries to California and other western states. These increases were partially offset by lower 2001 revenues resulting from contract remarketing on the TGP system during 2000 and the impact of the sales of the Midwestern Gas Transmission system in April 2001, Crystal Gas Storage in September 2000 and the East Tennessee Natural Gas and Sea Robin systems in the first quarter of 2000. Also contributing to the decrease were lower transportation revenues in 2001 on TGP as a result of higher proportion of short versus long hauls compared to 2000 and lower remarketing rates on released capacity in 2001 as a result of SNG's 2000 rate case settlement allowing customers to partially reduce their firm transportation capacity.

Operating expenses for the nine months ended September 30, 2001, were $346 million higher than the same period in 2000 primarily as a result of the merger-related and other charges in 2001 discussed previously under "Recent Developments." Also contributing to the increase were the impact of higher natural gas prices in the first and second quarters of 2001 on natural gas purchase contracts, the impact of reduced prices in the third quarter 2001 on natural gas imbalances and a one-time favorable adjustment to depreciation expense during the first quarter of 2000 as a result of approval to reactivate the Elba Island facility. Partially offsetting the increase were lower operating and maintenance expenses due to cost efficiencies following the merger and reduced operating and depreciation expenses due to the sales of the Midwestern Gas Transmission system in April 2001, Crystal Gas Storage in September 2000 and East Tennessee and Sea Robin in the first quarter of 2000.

Other income for the nine months ended September 30, 2001, was $12 million lower than the same period in 2000 due to lower equity earnings on Citrus Corp. and our Australian pipeline projects and the impact of the sales of our investments in the Empire State and Iroquois pipeline systems in the first and second quarters of 2001. Also contributing to the decrease were the sales of non-pipeline assets in 2000 and equity earnings resulting from the sale of our one-third interest in Destin Pipeline Company in the second quarter of 2000. Partially offsetting the decrease was increased earnings from our investment in the Alliance pipeline project which commenced operations in the fourth quarter 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 US, L.P. and Engage Energy 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 94 power plants in 20 countries and domestic and international 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 nine month period ended September 30, 2001, Merchant Energy earned $110 million in fee-based revenues from Chaparral and was reimbursed $15 million for operating expenses. For the nine months ended September 30, 2000, fee-based revenues were $60 million, and expense reimbursements were $15 million.

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.

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

| | Quarter Ended | | Nine Months Ended | |
|---|---|---|---|---|
| | 2001 | 2000 | 2001 | 2000 |
| | (In millions, except volume amounts) | | | |
| Trading and refining gross margin | $ 380 | $ 333 | $ 1,259 | $ 954 |
| Operating and other revenues | 162 | 131 | 523 | 392 |
| Operating expenses | (394) | (320) | (1,451) | (992) |
| Other income | 107 | 107 | 316 | 294 |
| EBIT | $ 255 | $ 251 | $ 647 | $ 648 |
| Volumes | | | | |
| Physical | | | | |
| Natural gas (BBtue/d) | 7,318 | 7,021 | 9,150 | 6,222 |
| Power (MMWh) | 61,571 | 41,692 | 143,349 | 89,366 |
| Crude oil and refined products (MBbls) | 174,112 | 163,146 | 509,895 | 492,029 |
| Coal (MTons) | 2,406 | 2,531 | 7,734 | 7,623 |
| Financial settlements (BBtue/d) | 231,942 | 144,022 | 222,075 | 133,795 |

*Third Quarter 2001 Compared to Third Quarter 2000*

Trading and refining gross margin consists of revenues from commodity trading and origination activities less the costs of commodities sold as well as revenues from refineries and chemical plants, less the cost of the feedstocks used in these refining processes. For the quarter ended September 30, 2001, these gross margins were $47 million higher than the same period in 2000. The increase was primarily due to higher commodity trading margins, primarily power, in 2001 as a result of higher trading volumes and price volatility and higher income from transactions originated during the third quarter of 2001. Partially offsetting the increase were lower refining margins resulting from weaker fuel and heavy crude product prices relative to crude oil prices during the third quarter of 2001 and lower refining throughput following a fire at our Aruba facility in April 2001, as well as the lease of our Corpus Christi refinery and related assets to Valero in June 2001. Also offsetting the increase were revenues recorded in 2000 on our West Georgia power generation facility which was sold in the fourth 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 the first and second quarters of 2001, California experienced sharp increases in natural gas prices and wholesale power prices due to energy shortages resulting, in part, 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 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 other parties in California to be a part of the long-term, stable solution to California's energy needs. We have established reserves that we believe are sufficient to cover our exposure to payment defaults from our California sales activities. As a result, we do not believe, based on information known to date, these matters will have a material impact on our operating results.

Our investee, Chaparral, has ownership interests in 11 power plants in the state of California. As of September 30, 2001, customers of these facilities had only partially paid for power generated, all of which arose prior to Pacific Gas and Electric's bankruptcy declaration. The combination of partial payments and Pacific Gas and Electric's bankruptcy declaration resulted in an event of default under the terms of each facility's loan agreement. Chaparral and Pacific Gas and Electric have amended the terms of existing power purchase agreements. In addition, Chaparral has received waivers from its lenders for the events of default. Management of Chaparral has indicated that it believes existing reserves against potential uncollectible accounts are adequate. 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 consolidated domestic and international power generation facilities, coal operations, and revenues from EnCap and the other financial services businesses of Merchant Energy. For the quarter ended September 30, 2001, operating and other revenues were $31 million higher than the same period in 2000. The increase resulted from higher management fees from Chaparral and revenues from the CEBU power project, a Philippine project in which we acquired an additional interest and began consolidating during the first quarter of 2001.

Operating expenses for the quarter ended September 30, 2001, were $74 million higher than the same period in 2000. The increase was primarily a result of changes in our estimates of environmental remediation costs and legal obligations arising out of an ongoing evaluation of our business processes and strategies following the Coastal merger. Also contributing to the increase were higher operating expenses resulting from the expansion of our operations in Europe, Mexico, Brazil, Singapore, our liquefied natural gas business and the consolidation of the CEBU power project. These increases were partially offset by lower operating expenses resulting from the lease of our Corpus Christi refinery and related assets to Valero in June 2001.

*Nine Months Ended 2001 Compared to Nine Months Ended 2000*

Trading and refining gross margin for the nine months ended September 30, 2001, was $305 million higher than the same period in 2000. The increase was primarily due to increased natural gas, power, crude oil and refined products trading margins resulting from increased trading volumes and price volatility as well as increased income from transactions originated during 2001. Also contributing to the increase were higher refining and chemical margins in the first and second quarters of 2001 due to higher throughput resulting from stronger commodity prices in the first quarter of 2001, partially offset by weaker prices in the third quarter of 2001, lower refining throughput following a fire at our Aruba facility in April 2001, and the lease of our Corpus Christi refinery and related assets to Valero in June 2001. Also offsetting the increase were revenues recorded in 2000 on our West Georgia power generation facility which was sold in the fourth quarter of 2000.

Operating and other revenues for the nine months ended September 30, 2001, were $131 million higher than the same period in 2000. The increase resulted from higher management fees from Chaparral, higher revenues from EnCap and our other financial services businesses, and revenues from the CEBU power project, a Philippine project in which we acquired an additional interest and began consolidating during the first quarter of 2001.

Operating expenses for the nine months ended September 30, 2001, were $459 million higher than the same period in 2000. The increase was primarily a result of merger-related costs and asset impairments associated with combining operations and implementing our combined strategy with Coastal and changes in our estimates of environmental remediation costs, legal obligations and spare parts inventory usability. Also contributing to the increase were higher operating expenses resulting from the expansion of our operations in Europe, Mexico, Brazil, Singapore, our liquefied natural gas business and the consolidation of the CEBU power project. The increase also resulted from higher fuel costs at our refineries due to higher natural gas prices. All increases were partially offset by lower operating expenses resulting from the lease of our Corpus Christi refinery and related assets to Valero in June 2001.

Other income for the nine months ended September 30, 2001, was $22 million higher than the same period in 2000. The increase was the result of marketing, agency and technical services fees on a Brazilian power transaction partially offset by lower earnings on an Argentine investment, gains in 2000 from the sale of a portion of our East Asia Power project and the sale of our interest in a Guatemala power project, both occurring in the first quarter of 2000.

**Production**

Production's operating results are driven by a variety of factors including its ability to locate and develop economic gas and oil reserves, extract those reserves with minimal production costs, sell the products at attractive 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 primarily through natural gas and oil swaps. Our hedging program is designed 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. Production's hedge 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 an analysis of these results for the periods ended September 30:

| | Quarter Ended | | Nine Months Ended | |
|---|---|---|---|---|
| | 2001 | 2000 | 2001 | 2000 |
| | (In millions, except volumes and prices) | | | |
| Natural gas | $ 507 | $ 330 | $ 1,459 | $ 982 |
| Oil, condensate and liquids | 77 | 59 | 240 | 187 |
| Other | 3 | 8 | 14 | 16 |
| Total operating revenues | 587 | 397 | 1,713 | 1,185 |
| Operating expenses | (419) | (240) | (1,071) | (697) |
| Other income (loss) | 1 | (8) | 1 | (16) |
| EBIT | $ 169 | $ 149 | $ 643 | $ 472 |
| Volumes and prices | | | | |
| Natural gas | | | | |
| Volumes (MMcf) | 146,366 | 126,975 | 419,587 | 386,130 |
| Average realized prices ($/Mcf) | $ 3.46 | $ 2.60 | $ 3.48 | $ 2.54 |
| Oil, condensate and liquids | | | | |
| Volumes (MBbls) | 3,562 | 2,739 | 10,049 | 8,523 |
| Average realized prices ($/Bbl) | $ 21.62 | $ 21.81 | $ 23.88 | $ 21.95 |

*Third Quarter 2001 Compared to Third Quarter 2000*

For the quarter ended September 30, 2001, operating revenues were $190 million higher than the same period in 2000. The increase was the combined result of higher realized natural gas prices coupled with higher production. Realized natural gas sales prices were 33 percent higher than the third quarter of 2000, and natural gas production volumes rose during the third quarter 2001 by 15 percent over the same period in 2000. Oil, condensate and liquids production volumes were 30 percent higher than the same period in 2000, with realized average prices slightly lower than 2000 levels.

Operating expenses for the quarter ended September 30, 2001, were $179 million higher than the same period in 2000 as a result of a non-cash full cost ceiling test charge related to our Canadian, Brazilian and other international production operations, primarily in Turkey, incurred in the current quarter and higher depletion expense in 2001 as a result of the increased production volumes and higher capitalized costs in the full cost pool.

*Nine Months Ended 2001 Compared to Nine Months Ended 2000*

For the nine months ended September 30, 2001, operating revenues were $528 million higher than the same period in 2000. The increase was the combined result of higher realized prices coupled with higher production. For the nine months ended September 30, 2001, realized natural gas sales prices were 37 percent higher than the same period in 2000, and natural gas production volumes rose by 9 percent over the same period in 2000. Oil, condensate and liquids production volumes were 18 percent higher than the same period in 2000, with average realized prices increasing 9 percent.

Operating expenses for the nine months ended September 30, 2001, were $374 million higher than the same period in 2000 as a result of a non-cash full cost ceiling test charge related to our Canadian, Brazilian and other international production operations, primarily in Turkey, incurred in the third quarter of 2001, higher depletion expense in 2001 as a result of the increased production volumes and higher capitalized costs in the full cost pool, merger-related costs and other charges related to our combined production operations and increased oilfield services costs in 2001. Also contributing to the increase were higher severance and other production taxes in 2001, which are generally tied to natural gas and oil prices.

**Field Services**

Our Field Services segment 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. Field Services also serves as the general partner of El Paso Energy Partners, L.P., a publicly traded master limited partnership. Through this relationship, Field Services earns a combination of management fees and partner distributions for services rendered to the partnership. Field Services attempts to balance its earnings from its activities through a combination of fixed-fee-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 market-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 these results are as follows for the periods ended September 30:

| | Quarter Ended | | Nine Months Ended | |
|---|---|---|---|---|
| | 2001 | 2000 | 2001 | 2000 |
| | (In millions, except volumes and prices) | | | |
| Gathering and treating margin | $ 76 | $ 59 | $ 231 | $ 171 |
| Processing margin | 60 | 48 | 187 | 140 |
| Other margin | 9 | 5 | 22 | 10 |
| Total gross margin | 145 | 112 | 440 | 321 |
| Operating expenses | (115) | (68) | (350) | (195) |
| Other income | 13 | 14 | 44 | 40 |
| EBIT | $ 43 | $ 58 | $ 134 | $ 166 |
| Volumes and prices | | | | |
| Gathering and treating | | | | |
| Volumes (BBtu/d) | 6,071 | 3,821 | 6,247 | 3,912 |
| Prices ($/MMBtu) | $ 0.14 | $ 0.17 | $ 0.13 | $ 0.16 |
| Processing | | | | |
| Volumes (inlet BBtu/d) | 4,551 | 3,124 | 4,263 | 3,048 |
| Prices ($/MMBtu) | $ 0.14 | $ 0.17 | $ 0.16 | $ 0.17 |

*Third Quarter 2001 Compared to Third Quarter 2000*

Total gross margin for the quarter ended September 30, 2001, was $33 million higher than the same period in 2000. The increase was a result of higher gathering and treating margins primarily due to higher volumes as a result of our acquisition of PG&E's Texas Midstream operations in December 2000. Processing margins were also higher primarily due to the processing operations acquired from PG&E. During the quarter ended September 30, 2001, average gathering, treating and processing rates were lower due to the different mix of assets acquired from PG&E.

Operating expenses for the quarter ended September 30, 2001, were $47 million higher than the same period in 2000. The increase was a result of higher operating costs and depreciation expense from the addition of PG&E's Texas Midstream operations, as well as merger-related costs arising from write-downs of assets, other merger charges and changes in our estimated environmental remediation liabilities in 2001.

*Nine Months Ended 2001 Compared to Nine Months Ended 2000*

Total gross margin for the nine months ended September 30, 2001, was $119 million higher than the same period in 2000. The increase was a result of higher gathering and treating margins primarily due to higher volumes as a result of our acquisition of PG&E's Texas Midstream operations in December 2000, along with higher natural gas prices in the San Juan Basin. Processing margins were also higher due to the processing operations acquired from PG&E and higher natural gas liquids prices in the San Juan Basin. During the nine months ended September 30, 2001, average gathering, treating and processing rates were lower compared to 2000 due to the different mix of assets resulting from the acquisition of PG&E.

Operating expenses for the nine months ended September 30, 2001, were $155 million higher than the same period in 2000. The increase was a result of higher operating, depreciation and tax expenses primarily from the addition of PG&E's Texas Midstream operations, as well as merger-related costs arising from commitments made related to FTC ordered sales of assets owned by El Paso Energy Partners, write-downs of assets, merger-related employee severance and relocation expenses and other merger charges and changes in our estimated environmental remediation liabilities in 2001.

Other income for the nine months ended September 30, 2001, was $4 million higher than the same period in 2000. The increase was a result of higher earnings in 2001 from our interests in El Paso Energy Partners, partially offset by equity investment losses from our Mobile Bay and Aux Sable liquids processing facilities and a 2000 gain on the sale of our Colorado dry gathering system.

**Corporate and Other, net**

*Third Quarter 2001 Compared to Third Quarter 2000*

Corporate expenses, which include results from our retail gas stations and telecommunications businesses for the quarter ended September 30, 2001, were $82 million higher than the same period in 2000. The increase was primarily a result of merger-related charges in connection with our January 2001 merger with Coastal, costs associated with increased estimates of environmental remediation costs and legal obligations in our corporate operations based on an ongoing evaluation of our operating standards and plans following the Coastal merger and lower margins due to the sale of our Texas and Florida retail gas stations in the third quarter of 2001. Operating losses associated with our telecommunications business during the third quarter of 2001 were approximately $18 million.

*Nine Months Ended 2001 Compared to Nine Months Ended 2000*

Corporate expenses for the nine months ended September 30, 2001, were $1,295 million higher than the same period in 2000. The increase was primarily a result of merger-related charges in connection with our January 2001 merger with Coastal, costs associated with increased estimates of environmental remediation costs, legal obligations and usability of spare parts inventories in our corporate operations based on an ongoing evaluation of our operating standards, strategies and plans following the Coastal merger and lower margins due to the sale of substantially all of our retail gas stations in 2001. Operating losses associated with our telecommunications business during this period were approximately $45 million.

**Interest and Debt Expense**

Interest and debt expense for the quarter and nine months ended September 30, 2001, was $6 million and $108 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 anticipate interest and debt expenses will continue to exceed last year's levels throughout the remainder of 2001.

**Minority Interest**

Minority interest for the quarter ended September 30, 2001, was $3 million lower primarily due to lower interest rates, which is offset by the sale of additional preferred interests in Clydesdale Associates, L.P. in December 2000.

Minority interest for the nine months ended September 30, 2001, was $24 million higher due to the sale of preferred interests in Clydesdale Associates, L.P. in May and December 2000, partially offset by lower interest rates.

For a further discussion of our borrowing and other financing activities during the period, see Part I, Item I, Financial Statements, Note 10.

### Income Taxes

The income tax expense for the quarter and nine months ended September 30, 2001, were $102 million and $4 million, resulting in effective tax rates that were lower than the statutory rate of 35 percent primarily due to the following:

- the non-deductible portion of merger-related costs and, for the nine months ended September 30, 2001, 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.

The income tax expense for the quarter and nine months ended September 30, 2000, were $135 million and $409 million, resulting in effective tax rates of 32 percent for both periods. Our effective tax rates were different than the statutory rate of 35 percent primarily due to the following:

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

## Liquidity and Capital Resources

### General

During the nine months ended September 30, 2001, we have generated over $6 billion through a combination of cash from operations and the issuance of long term debt and other financing instruments. This cash was used to increase our property, plant and equipment, our investments and to repay debt. As of September 30, 2001, we have a renewable $3 billion, 364-day revolving credit and competitive advance facility and a $1 billion, 3-year revolving credit and competitive advance facility, which were established primarily to support our commercial paper program. No amounts were outstanding under these facilities, and our commercial paper balance was $1,359 million. We also have $1.8 billion capacity remaining under our current shelf registration statement filed with the Securities and Exchange Commission, and TGP has $200 million remaining under its shelf registration.

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.

### Cash From Operating Activities

Net cash provided by our operating activities was $3,376 million for the nine months ended September 30, 2001, compared to $369 million for the same period of 2000. The increase was primarily due to liquidations of net derivative trading positions during the first half of 2001, coupled with the impact of lower commodity prices. 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 $3,455 million for the nine months ended September 30, 2001. Our investing activities principally consisted of additions to property, plant, and equipment, including an increase in our oil and natural gas properties for developmental drilling, and expenditures for expansion and construction projects. We had additions to joint ventures and investments in unconsolidated affiliates, primarily related to our investment in five coal-fired power plants and two international power companies located in Brazil and China. Our additions to investments also consist of short-term notes from unconsolidated affiliates. In August 2001, we completed our acquisition of Velvet Exploration Ltd., a Canadian exploration and development company, with properties located in the Foothills and Deep Basin areas of western Alberta Province, at a cost of approximately $230 million. Cash inflows from investment-related activities included proceeds from the sales of our Midwestern Gas Transmission system, our Gulfstream pipeline project, and other property, plant, and equipment assets, along with proceeds from the sale of substantially all of our retail gas stations in 2001. Additional cash inflows included the sale of our interests in the Empire State and Iroquois pipeline systems and a health management investment portfolio.

### Cash From Financing Activities

Net cash provided by our financing activities was $115 million for the nine months ended September 30, 2001. During 2001, 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, short-term notes, and issuances of common stock as a result of the exercise of employee stock options.

In October 2001, we declared a quarterly dividend of $0.2125 per share on our common stock, payable on January 2, 2002, to stockholders of record on December 7, 2001. Also, during the six months ended June 30, 2001, we paid dividends of $12 million on the 8¼% Series A cumulative preferred stock of our subsidiary, El Paso Tennessee Pipeline Co.

For an additional discussion of our investing and financing activities, see Item 1, Financial Statements, Notes 10 and 13.

## Commitments and Contingencies

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

## New Accounting Pronouncements Not Yet Adopted

See Item 1, Financial Statements, Note 14, which is incorporated herein by reference.

## CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

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

- earnings per share;
- capital and other expenditures;
- dividends;
- financing plans;
- capital structure;
- 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 potential contingent liabilities, sanctions, or business restrictions in connection with the energy crisis in California;
- the political and economic risks associated with current and future operations; 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/A filed on May 17, 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/A filed on May 17, 2001.

## PART II — OTHER INFORMATION

### Item 1. Legal Proceedings

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

The *California* cases are: four filed in the Superior Court of Los Angeles County (*Continental Forge Company, et al v. Southern California Gas Company, et al,* filed September 25, 2000; *Berg v. Southern California Gas Company, et al;* filed December 18, 2000; *The City of Los Angeles, et al v. Southern California Gas Company, et al* and *The City of Long Beach, et al v. Southern California Gas Company, et al,* both filed March 20, 2001); two filed in the Superior Court of San Diego County (*John W.H.K. Phillip v. El Paso Merchant Energy* and *John Phillip v. El Paso Merchant Energy,* both filed December 13, 2000); and three filed in the Superior Court of San Francisco County (*Sweetie's, et al v. El Paso Corporation, et al,* filed March 22, 2001; *Philip Hackett, et al v. El Paso Corporation, et al,* filed May 9, 2001; and *California Dairies, Inc., et al v. El Paso Corporation, et al,* filed May 21, 2001). All of the cases except Hacket were consolidated before the U.S. District Court in Nevada for pretrial activities. The shareholder case is styled *Clark, et al v. Allumbaugh, et al,* Superior Court of Orange County, filed August 23, 2001.

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 settled in June 2001), 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 alleged five probable violations of the regulations of the Department of Transportation's Office of Pipeline Safety are: 1) failure to perform appropriate tasks to prevent corrosion, with an associated proposed fine of $500,000; 2) failure to investigate and minimize internal corrosion, with an associated proposed fine of $1,000,000; 3) failure to consider unusual operating and maintenance conditions and respond appropriately, with an associated proposed fine of $500,000; 4) failure to follow company procedures, with an associated proposed fine of $500,000; and 5) failure to maintain topographical diagrams, with an associated proposed fine of $25,000.

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

None.

### Item 3. Defaults Upon Senior Securities

None.

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

None.

**Item 5. Other Information**

None.

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

a. Exhibits

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

| Exhibit Number | Description |
|---|---|
| 4.A | — Certificate of Designation, Preferences and Rights of Series C Mandatorily Convertible Single Reset Preferred Stock of El Paso Corporation as filed with the Delaware Secretary of State on October 31, 2001. |
| †10.C.1 | — Amendment No. 5 to Omnibus Compensation Plan effective as of August 1, 2001. |
| †10.T.2 | — Amendment No. 6 to the El Paso Employee Stock Purchase Plan effective as of August 1, 2001. |
| †10.CC | — Pledge and Security Agreement, and Promissory Note, each dated August 16, 2001, by and between El Paso and William A. Wise. |

† Denotes management contracts.

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 July 30, 2001, announcing that we entered into a Terms Agreement with J.P. Morgan Securities, Inc., ABN AMRO Incorporated, and Banc of America Securities, LLC, pursuant to which we issued $700 million aggregate principal amount of 7.8% Medium Term Notes due 2011.

We filed an amended current report on Form 8-K/A, dated July 31, 2001, to provide additional information reflecting the use of proceeds from the issuance of our 7.8% Medium Term Notes.

**SIGNATURES**

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

EL PASO CORPORATION

Date: November 9, 2001

/s/ H. BRENT AUSTIN

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

Date: November 9, 2001

/s/ JEFFREY I. BEASON

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

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