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

Form 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2003

or

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

For the transition period from to

Commission file number 1-7176

El Paso CGP Company

(Exact Name of Registrant as Specified in its Charter)

Delaware	**74-1734212**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)
El Paso Building **1001 Louisiana Street** **Houston, Texas**	**77002**
(Address of Principal Executive Offices)	(Zip Code)

Telephone Number: **(713) 420-2600**

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes ☐ No ☑

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Common Stock, par value $1 per share. Shares outstanding on August 14, 2003: 1,000

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

EL PASO CGP COMPANY

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Below is a list of terms that are common to our industry and used throughout this document:

/d	= per day	Mcf	= thousand cubic feet
Bbl	= barrels	Mcfe	= thousand cubic feet of gas equivalents
BBtu	= billion British thermal units	MMBtu	= million British thermal units
MBbls	= thousand barrels	MMcf	= million cubic feet

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 of oil is equal to six Mcf of natural gas. Also, when we refer to cubic feet measurements, all measurements are at a pressure of 14.73 pounds per square inch.

When we refer to "us", "we", "our", "ours", or "El Paso CGP", we are describing El Paso CGP Company and/or our subsidiaries.

PART I — FINANCIAL INFORMATION

Item 1. Financial Statements

EL PASO CGP COMPANY

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

	Quarters Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
Operating revenues	$ 610	$ 758	$ 1,348	$2,455
Operating expenses				
Cost of products and services	128	99	292	711
Operation and maintenance	131	183	265	365
Depreciation, depletion and amortization	143	148	280	329
Ceiling test charges	—	233	—	243
Gain on long-lived assets	(25)	(10)	(17)	(21)
Taxes, other than income taxes	20	12	47	41
	397	665	867	1,668
Operating income	213	93	481	787
Earnings (losses) from unconsolidated affiliates	(54)	36	(15)	84
Other income	9	15	18	28
Other expenses	(3)	(8)	(6)	(150)
Interest and debt expense	(100)	(104)	(199)	(207)
Affiliated interest expense, net	(7)	(2)	(14)	(6)
Distributions on preferred interests of consolidated subsidiaries	(7)	(11)	(14)	(21)
Income before income taxes	51	19	251	515
Income taxes	77	5	89	167
Income (loss) from continuing operations	(26)	14	162	348
Discontinued operations, net of income taxes	(916)	(116)	(1,138)	(56)
Cumulative effect of accounting changes, net of income taxes	—	14	(21)	14
Net income (loss)	$ (942)	$ (88)	$ (997)	$ 306

See accompanying notes.

EL PASO CGP COMPANY

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

	June 30, 2003	December 31, 2002
ASSETS		
Current assets		
Cash and cash equivalents	$ 179	$ 128
Accounts and notes receivable		
Customers, net of allowance of $26 in 2003 and $21 in 2002	207	345
Affiliates	531	521
Other	130	187
Inventory	63	62
Assets from price risk management activities	92	102
Assets of discontinued operations	1,711	2,121
Other	179	195
Total current assets	3,092	3,661
Property, plant and equipment, at cost		
Natural gas and oil properties, at full cost	7,985	7,479
Pipelines	6,374	6,522
Power facilities	479	478
Gathering and processing systems	161	239
Other	91	92
	15,090	14,810
Less accumulated depreciation, depletion and amortization	6,634	6,559
Total property, plant and equipment, net	8,456	8,251
Other assets		
Investments in unconsolidated affiliates	1,467	1,528
Assets from price risk management activities	881	956
Goodwill and other intangible assets, net	492	495
Assets of discontinued operations	—	1,944
Other	527	398
	3,367	5,321
Total assets	$14,915	$17,233

See accompanying notes.

EL PASO CGP COMPANY

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

	June 30, 2003	December 31, 2002
LIABILITIES AND STOCKHOLDER'S EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 179	$ 208
Affiliates	96	87
Other	212	261
Current maturities of long-term debt	560	369
Notes payable to affiliates	1,602	2,374
Liabilities from price risk management activities	208	215
Liabilities of discontinued operations	929	1,373
Other	331	274
Total current liabilities	4,117	5,161
Long-term debt	4,797	4,985
Other		
Liabilities from price risk management activities	9	24
Deferred income taxes	1,535	1,753
Other	400	357
	1,944	2,134
Commitments and contingencies		
Securities of subsidiaries		
Preferred interests of consolidated subsidiaries	400	400
Minority interests of consolidated subsidiaries	118	253
	518	653
Stockholder's equity		
Common stock, par value $1 per share; authorized and issued 1,000 shares	—	—
Additional paid-in capital	1,502	1,339
Retained earnings	2,105	3,102
Accumulated other comprehensive loss	(68)	(141)
Total stockholder's equity	3,539	4,300
Total liabilities and stockholder's equity	$14,915	$17,233

See accompanying notes.

EL PASO CGP COMPANY

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

	Six Months Ended June 30, 2003	Six Months Ended June 30, 2002
Cash flows from operating activities		
Net income (loss)	$ (997)	$ 306
Less loss from discontinued operations, net of income taxes	(1,138)	(56)
Net income from continuing operations	141	362
Adjustments to reconcile net income (loss) to net cash from operating activities		
Non-cash gains from trading and power activities	(22)	(481)
Depreciation, depletion and amortization	280	329
Ceiling test charges	—	243
Gain on long-lived assets	(17)	(21)
Undistributed earnings of unconsolidated affiliates	(33)	(24)
Deferred income tax expense (benefit)	64	(74)
Cumulative effect of accounting changes	21	(14)
Other non-cash income items	59	(5)
Working capital changes	335	554
Non-working capital changes and other	112	(93)
Cash provided by continuing operations	940	776
Cash provided by (used in) discontinued operations	90	(196)
Net cash provided by operating activities	1,030	580
Cash flows from investing activities		
Additions to property, plant and equipment	(617)	(667)
Purchases of interests in equity investments	(8)	(121)
Net proceeds from the sale of assets and investments	291	839
Net change in restricted cash	(47)	(68)
Net change in notes receivable from unconsolidated affiliates	(259)	98
Other	22	45
Cash provided by (used in) continuing operations	(618)	126
Cash provided by (used in) investing activities by discontinued operations	329	(90)
Net cash provided by (used in) investing activities	(289)	36
Cash flows from financing activities		
Net repayments under commercial paper and short-term credit facilities	—	(30)
Net proceeds from the issuance of long-term debt	288	90
Payments to retire long-term debt	(297)	(796)
Repayments of notes payable	—	(55)
Net change in affiliated advances payable	(682)	569
Contributions from discontinued operations	419	(603)
Other	1	(54)
Cash used in continuing operations	(271)	(879)
Cash provided by (used in) financing activities by discontinued operations	(419)	296
Net cash used in financing activities	(690)	(583)
Increase in cash and cash equivalents	51	33
Less increase in cash and cash equivalents related to discontinued operations	—	10
Increase in cash and cash equivalents from continuing operations	51	23
Cash and cash equivalents		
Beginning of period	128	141
End of period	$ 179	$ 164

See accompanying notes.

EL PASO CGP COMPANY

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

	Quarters Ended June 30,		Six Months Ended June 30	
	2003	2002	2003	2002
Net income (loss)	$(942)	$ (88)	$(997)	$ 306
Foreign currency translation adjustments	51	23	91	23
Unrealized net gains (losses) from cash flow hedging activity				
Unrealized mark-to-market losses arising during period (net of income taxes of $17 and $41 in 2003 and $43 and $113 in 2002)	(28)	(77)	(72)	(195)
Reclassification adjustments for changes in initial value to the settlement date (net of income taxes of $8 and $30 in 2003 and $18 and $65 in 2002)	13	(37)	54	(121)
Other comprehensive income (loss)	36	(91)	73	(293)
Comprehensive income (loss)	$(906)	$(179)	$(924)	$ 13

See accompanying notes.

EL PASO CGP COMPANY

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Basis of Presentation

We prepared this Quarterly Report on Form 10-Q under the rules and regulations of the United States Securities and Exchange Commission. Because this is an interim period filing presented using a condensed format, it does not include all of the disclosures required by generally accepted accounting principles. You should read it along with our 2002 Annual Report on Form 10-K, which includes a summary of our significant accounting policies and other disclosures. The financial statements as of June 30, 2003, and for the quarters and six months ended June 30, 2003 and 2002, are unaudited. We derived the balance sheet as of December 31, 2002, from the audited balance sheet filed in our 2002 Form 10-K. In our opinion, we have made all adjustments which are of a normal, recurring nature to fairly present our interim period results. Due to the seasonal nature of our businesses, information for interim periods may not indicate the results of operations for the entire year. Our results for all periods presented have been reclassified to reflect our petroleum and coal mining operations as discontinued operations. In addition, prior period information presented in these financial statements includes reclassifications which were made to conform to the current period presentation. These reclassifications have no effect on our previously reported net income or stockholder's equity.

Significant Accounting Policies

Our accounting policies are consistent with those discussed in our 2002 Form 10-K, except as follows:

Accounting for Asset Retirement Obligations. On January 1, 2003, we adopted Statement of Financial Accounting Standard (SFAS) No. 143, *Accounting for Asset Retirement Obligations.* SFAS No. 143 requires that we record a liability for retirement and removal costs of long-lived assets used in our business. This liability is recorded at its estimated fair value, with a corresponding increase to property, plant and equipment. This increase in property, plant and equipment is then depreciated over the remaining useful life of the long-lived asset to which that liability relates. An ongoing expense is also recognized for changes in the value of the liability as a result of the passage of time, which we also record in depreciation, depletion and amortization expense in our income statement. In the first quarter of 2003, we recorded a charge as a cumulative effect of accounting change of approximately $21 million, net of income taxes related to our adoption of SFAS No. 143. We also recorded property, plant and equipment of $111 million and non-current asset retirement obligations of $156 million as of January 1, 2003. Our asset retirement obligations are associated with our natural gas and oil wells and related infrastructure in our Production segment and our natural gas storage wells in our Pipelines segment. We have obligations to plug wells when production on those wells is exhausted, and we abandon them. We currently forecast that these obligations will be met at various times generally over the next 10 years, based on the expected productive lives of the wells and the estimated timing of plugging and abandoning those wells. The net asset retirement liability as of January 1, 2003 and June 30, 2003, reported in other non-current liabilities in our balance sheet, and the changes in the net liability for the six months ended June 30, 2003, were as follows (in millions):

Liability at January 1, 2003	$156
Liabilities settled in 2003	(27)
Accretion expense in 2003	5
Liabilities incurred in 2003	1
Changes in estimate	(7)
Net liability at June 30, 2003	$128

Our changes in estimate represent changes to the expected amount and timing of payments to settle our asset retirement obligations. These changes primarily result from obtaining new information about the timing of our obligations to plug our natural gas wells and the costs to do so. Had we adopted SFAS No. 143 as of January 1, 2002, our non-current retirement liabilities would have been approximately $130 million as of

January 1, 2002, and our income from continuing operations and net income for the quarter and six months ended June 30, 2002, would have been lower by $2 million and $4 million.

Accounting for Costs Associated with Exit or Disposal Activities. On January 1, 2003, we adopted SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*. SFAS No. 146 requires that we recognize costs associated with exit or disposal activities when they are incurred rather than when we commit to an exit or disposal plan. We applied the provisions of SFAS No. 146 in accounting for restructuring costs we incurred during 2003. For the quarter and six months ended June 30, 2003, we recorded $2 million and $9 million of employee severance costs, less income taxes of less than $1 million and $1 million associated with our discontinued operations, substantially all of which had been paid as of June 30, 2003. As we continue to evaluate our business activities and seek additional cost savings, we expect to incur additional charges that will be evaluated under this accounting standard.

Accounting for Guarantees. On January 1, 2003, we adopted Financial Accounting Standards Board Interpretation (FIN) No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others*. FIN No. 45 requires that we record a liability for guarantees, including financial performance and fair value guarantees, issued after December 31, 2002, at their fair value when they are issued. There was no initial financial statement impact of adopting this standard.

Accounting for Regulated Operations. Our natural gas pipelines are subject to the regulations and accounting procedures of the Federal Energy Regulatory Commission (FERC) in accordance with the Natural Gas Act of 1938 and Natural Gas Policy Act of 1978. In 1996, we discontinued the application of regulatory accounting principles under SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*. We continue to evaluate the application of SFAS No. 71 for changes in the competitive environment and our operating cost structures. See a further discussion of our accounting for regulated operations in our 2002 Form 10-K.

2. Divestitures

During 2003, we completed or announced the sale of a number of assets and investments in each of our business segments. The gains and losses on these sales reflected below do not include any asset impairments we may have recognized at the time we decided to sell the asset or investment. See Notes 4, 6 and 13 for a discussion of impairments on long-lived assets, assets treated as discontinued operations and investments in unconsolidated affiliates.

Segment	Proceeds	Pre-tax Gain (Loss)	Significant Asset and Investment Divestitures
	(In millions)		
Completed as of June 30, 2003			
Pipelines	$ 63	$ 8	• Panhandle gathering system located in Texas • 2.1 percent interest in Alliance pipeline and related assets • Helium processing operations in Oklahoma • Sulfur extraction facility
Production	195	5	• Natural gas and oil properties located in western Canada, New Mexico and the Gulf of Mexico
Field Services	94	19	• Gathering systems located in Wyoming • Midstream assets in Mid-Continent region
Continuing operations	352(1)	32	
Discontinued operations	530	49	• Coal reserves and properties in West Virginia, Virginia and Kentucky • Corpus Christi refinery • Florida petroleum terminals and tug and barge operations • Louisiana lease crude business
Total	$882	$81	

(1) Includes $61 million of net proceeds related to the working capital of the assets sold. Working capital is reflected in cash flows from operating activities rather than proceeds from asset sales.

Segment	Proceeds	Pre-tax Gain (Loss)	Significant Asset and Investment Divestitures
	(In millions)		
Announced to date[1]			
Corporate and Other	$ 28	$(1)	• Aircraft[2] • Harbortown development
Continuing operations	28	(1)	
Discontinued operations	332	10	• Petroleum asphalt operations and lease crude business[2] • Eagle Point refinery and related pipeline assets[3]
Total	$360	$ 9	

(1) Amounts on sales that have been announced or are under contract for sale are estimates, subject to customary regulatory approvals, final sale negotiations and other conditions.

(2) These sales were completed in July 2003.

(3) We have entered into a non-binding letter of intent to sell these assets.

Each period, we evaluate our potential asset sales to determine if any meet the criteria as held for sale or as discontinued operations under SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets.* The more significant criteria we evaluate are whether:

- Management, with the authority to approve the sale, commits to a plan to sell the asset;
- The asset is available for immediate sale in its present condition;
- An active program to locate a buyer and other actions required to complete the sale have been started; and
- The sale of the asset is probable and is expected to be completed within one year.

To the extent that all of these criteria as well as the other requirements of SFAS No. 144 are met, we classify an asset as held for sale or, if appropriate, discontinued operations. For example, El Paso's Board of Directors (or a designated subcommittee of its Board) is required to approve asset dispositions greater than specified thresholds. Unless specific approval is received by its Board (or a designated subcommittee) by the end of a given reporting period to commit to a plan to sell an asset, we would not classify it as held for sale or discontinued operations in that reporting period even if it is management's stated intent to sell the asset. As of December 31, 2002, we had $64 million of long-lived assets classified as held for sale and reflected in current assets in our balance sheet, all of which had been sold as of June 30, 2003. We also had approximately $1.7 billion of assets classified as discontinued operations. See a further discussion of our discontinued operations in Note 6.

We continue to evaluate assets we may sell in the future. As specific assets are identified for sale, we will be required to record them at the lower of fair value or historical cost. This may require us to assess them for possible impairment. The amounts of the impairment charges, if any, will generally be based on estimates of the expected fair value of the assets as determined by market data obtained through the sales process or by assessing the probability weighted cash flows of the asset. For a discussion of impairment charges incurred on our long-lived assets, see Note 4; for our impairments related to our discontinued operations, see Note 6; and for impairments on our investments in unconsolidated affiliates, see Note 13.

In February 2002, we sold CIG Trailblazer Gas Company, L.L.C., a company which owned pipeline expansion rights, to a third party. Our Pipelines segment recorded a gain on this sale of approximately $11 million.

In March 2002, we sold natural gas and oil properties to El Paso and to third parties. Net proceeds from these sales were approximately $500 million. We did not recognize a gain or loss on these sales because we apply the full cost method of accounting for our oil and natural gas operations (which requires that gains or losses on property sales are only recognized in certain circumstances).

In May and June 2002, we completed sales of natural gas and oil properties, a natural gas gathering system and a natural gas plant. Net proceeds from these sales were approximately $325 million. We recognized a gain on long-lived assets of $10 million, $6 million after taxes, on the natural gas gathering system and the plant.

3. Ceiling Test Charges

Under the full cost method of accounting for natural gas and oil properties, we perform quarterly ceiling tests to determine 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, net of related income tax effects.

For the quarter and six months ended June 30, 2003, our ceiling test charges were less than $1 million. For the six months ended June 30, 2002, we recorded ceiling test charges of $243 million, of which $10 million was charged during the first quarter and $233 million during the second quarter. The charges include $226 million for our Canadian full cost pool, $10 million for our Brazilian full cost pool and $7 million for other international production operations. These write-downs were based upon the daily posted natural gas and oil prices as of June 30, 2002, adjusted for oil field or natural gas gathering hub and wellhead price differences, as appropriate. The charge for our Canadian full cost pool primarily resulted from a low daily posted price for natural gas at the end of the second quarter of 2002, which was approximately $1.43 MMBtu.

We use financial instruments to hedge against the volatility of natural gas and oil prices. The impact of these hedges was considered in determining our ceiling test charges and will be factored into future ceiling test calculations. The charges for our international cost pools would not have changed had the impact of our hedges not been included in calculating our 2002 ceiling test charges since we do not significantly hedge our international production activities. However, we would have incurred an additional charge of $28 million related to our United States full cost pool.

4. Gain on Long-Lived Assets

Our gain on long-lived assets from continuing operations consists of net realized gains and losses on sales of long-lived assets and impairments of long-lived assets, and was as follows:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
	(In millions)			
Net realized gain	$ 30	$10	$ 31	$21
Asset impairments[1]	(5)	—	(14)	—
Gain on long-lived assets	$ 25	$10	$ 17	21

[1] These amounts exclude approximately $987 million and $1.3 billion of asset impairments for the quarter and six months ended June 30, 2003, related to our petroleum operations that were reclassified as discontinued operations.

Net Realized Gain

Our 2003 net realized gains were primarily related to the sales of the Mid-Continent midstream assets in our Field Services segment, the Table Rock sulfur extraction facility in our Pipelines segment and non-full cost pool assets in our Production segment. Our 2002 net realized gains were primarily related to the sales of pipeline expansion rights in our Pipelines segment and the sale of the Dragon Trail processing plant in our Field Services segment.

Asset Impairments

We are required to test assets for recoverability whenever events or changes in circumstances indicate that the carrying amount of these assets may not be fully recoverable. One triggering event is the expectation that it is more likely than not that we will sell or dispose of the asset before the end of its estimated useful life. Based on El Paso's intent to dispose of a number of our assets, we tested those assets for recoverability during the first and second quarters of 2003. As a result of these assessments, we recognized impairments of $5 million in the second quarter of 2003 and $14 million for the first six months of 2003 in our Production segment related to non-full cost assets in Canada. For additional asset impairments on our discontinued operations and investments in unconsolidated affiliates, see Notes 6 and 13.

5. Other Expenses

Other expenses for the quarter and six months ended June 30, 2002, were $8 million and $150 million. Included in other expenses for the six months ended June 30, 2002 was a $90 million steam contract termination fee paid to our Eagle Point refinery (in the petroleum division) by our Eagle Point Cogeneration facility (in our global power division of our Merchant Energy segment) in the first quarter of 2002. These amounts were eliminated in consolidation since the income associated with the petroleum division is reflected in discontinued operations while the power division's expense is included as part of our Merchant Energy's segment results. In the first six months of 2002, other expenses also included $52 million of minority interest in our consolidated subsidiaries.

6. Discontinued Operations

Petroleum Operations

In June 2003, El Paso's Board of Directors authorized the sale of substantially all of our petroleum operations, including our Aruba refinery, our Unilube blending operations, our domestic and international terminalling facilities and our petrochemical and chemical plants. The Board's actions were in addition to previous actions taken when they approved the sales of our Eagle Point refinery, our asphalt business and our lease crude operations. Based on our intent to dispose of these operations, we were required to adjust these assets to their estimated fair value. As a result, we recognized a pre-tax charge of approximately $987 million during the second quarter of 2003 related to our petroleum and chemical assets. This charge was in addition to the $350 million pre-tax impairment charge recognized during the first quarter of 2003 when El Paso announced its intent to sell our Eagle Point refinery and several chemical assets. These impairments were based on a comparison of the carrying value of the underlying assets to their estimated fair value. Our fair value estimates were based on preliminary market data obtained through the early stages of the sales process and an analysis of expected discounted cash flows. The magnitude of these charges was impacted by a number of factors, including the nature of the assets and our established time frame for completing the sales, among other factors. Our petroleum operations and assets were historically included in our Merchant Energy segment, and we reclassified these assets and operations from Merchant Energy to discontinued operations for all periods presented in these financial statements. We will also be required to reflect these assets as discontinued operations in our annual periods that were previously reported in our 2002 Form 10-K.

Of our second quarter 2003 impairment charge on our Aruba refinery, approximately $50 million relates to a portion of the facility we lease under an operating lease. During the second quarter, we amended this lease to provide a full guarantee to all the parties who invested in the lessors. As a result, we consolidated the lessor during the second quarter of 2003, increasing our total fixed assets by $370 million (prior to impairment) and our long-term debt by $370 million. As a result of El Paso's intent to exit substantially all of our petroleum operations, these leased assets and associated debt were also reclassified as discontinued operations. Our $50 million impairment charge was based on the cost of these fixed assets relative to their estimated fair value.

In the second quarter of 2003, we entered into a product offtake agreement for the sale of a number of the products produced at our Aruba refinery. As a result of this contract, the buyer became the single largest customer of our Aruba refinery, purchasing approximately 75 percent of the products produced at that plant.

The agreement is for one year with two one-year extensions at the buyer's option. We have the right to terminate the agreement when the refinery is sold.

Coal Mining Operations

In the latter part of 2002 and the first quarter of 2003, we sold our coal mining operations. These operations consisted of fifteen active underground and two surface mines located in Kentucky, Virginia and West Virginia. Following the authorization of the sale by our Board of Directors, we compared the carrying value of the underlying assets to our estimated sales proceeds, net of estimated selling costs, based on bids received in the sales process. Because this carrying value was higher than our estimated net sales proceeds, we recorded an impairment charge of $148 million in our total loss from discontinued operations in the second quarter of 2002.

Our petroleum operations and our coal mining operations, which were historically included in our Merchant Energy segment, have been reclassified as discontinued operations in our financial statements for all of the historical periods presented. We will also be required to reflect them as discontinued operations for all historical annual periods previously reported in our 2002 Form 10-K. In addition, we reclassified all of the assets and liabilities of our petroleum operations as of June 30, 2003 to other current assets and liabilities. The summarized financial results and financial position data of discontinued operations were as follows:

Operating Results

	Quarter Ended June 30,		
	Petroleum	**Coal Mining**	**Total**
		(In millions)	
2003			
Revenues	$ 1,525	$ —	$ 1,525
Costs and expenses	(1,623)	—	(1,623)
Loss on long-lived assets	(990)	—	(990)
Other expense	(21)	—	(21)
Interest and debt expense	(4)	—	(4)
Loss before income taxes	(1,113)	—	(1,113)
Income taxes	(197)	—	(197)
Loss from discontinued operations, net of income taxes	$ (916)	$ —	$ (916)
2002			
Revenues	$ 1,197	$101	$ 1,298
Costs and expenses	(1,261)	(68)	(1,329)
Gain (loss) on long-lived assets	2	(148)	(146)
Other income (expense)	(2)	6	4
Interest and debt expense	(10)	—	(10)
Loss before income taxes	(74)	(109)	(183)
Income taxes	(25)	(42)	(67)
Loss from discontinued operations, net of income taxes	$ (49)	$(67)	$ (116)

	Six Months Ended June 30,		
	Petroleum	Coal Mining	Total
	(In millions)		
2003			
Revenues	$ 3,704	$ 27	$ 3,731
Costs and expenses	(3,767)	(21)	(3,788)
Loss on long-lived assets	(1,286)	(3)	(1,289)
Other income (expense)	(14)	1	(13)
Interest and debt expense	(4)	—	(4)
Income (loss) before income taxes	(1,367)	4	(1,363)
Income taxes	(226)	1	(225)
Income (loss) from discontinued operations, net of income taxes	$(1,141)	$ 3	$(1,138)
2002			
Revenues	$ 2,062	$ 168	$ 2,230
Costs and expenses	(2,099)	(164)	(2,263)
Gain (loss) on long-lived assets	2	(148)	(146)
Other income	94	6	100
Interest and debt expense	(13)	—	(13)
Income (loss) before income taxes	46	(138)	(92)
Income taxes	16	(52)	(36)
Income (loss) from discontinued operations, net of income taxes	$ 30	$ (86)	$ (56)

Financial Position Data

	June 30, 2003		
	Petroleum	Coal Mining	Total
	(In millions)		
Assets of discontinued operations			
Accounts and notes receivables	$ 423	$ —	$ 423
Inventory	435	—	435
Other current assets	66	—	66
Property, plant and equipment, net	673	—	673
Other non-current assets	114	—	114
Total assets	$ 1,711	$ —	$ 1,711
Liabilities of discontinued operations			
Accounts payable	$ 394	$ —	$ 394
Other current liabilities	129	—	129
Notes payable	370	—	370
Environmental remediation reserve	36	—	36
Total liabilities	$ 929	$ —	$ 929

	December 31, 2002		
	Petroleum	Coal Mining	Total
	(In millions)		
Assets of discontinued operations			
Accounts and notes receivables	$1,229	$ 29	$1,258
Inventory	635	14	649
Other current assets	80	1	81
Property, plant and equipment, net	1,950	46	1,996
Other non-current assets	65	16	81
Total assets	$3,959	$106	$4,065
Liabilities of discontinued operations			
Accounts payable	$1,154	$ 20	$1,174
Other current liabilities	180	5	185
Environmental remediation reserve	86	15	101
Other non-current liabilities	1	—	1
Total liabilities	$1,421	$ 40	$1,461

7. Cumulative Effect of Accounting Changes

On January 1, 2003, we adopted SFAS No. 143. As a result, we recorded a cumulative effect of an accounting change of approximately $21 million, net of income taxes (see Note 1).

In the second quarter of 2002, we also adopted DIG Issue No. C-16, *Scope Exceptions: Applying the Normal Purchases and Sales Exception to Contracts that Combine a Forward Contract and Purchased Option Contract.* One of our unconsolidated affiliates, the Midland Cogeneration Venture Limited Partnership, recognized a gain on one fuel supply contract upon adoption of this new rule, and we recorded a gain of $14 million, net of income taxes, as a cumulative effect of an accounting change in our income statement for our proportionate share of this gain.

8. Financial Instruments and Price Risk Management Activities

The following table summarizes the carrying value of our price risk management assets and liabilities as of June 30, 2003 and December 31, 2002:

	June 30, 2003	December 31, 2002
	(In millions)	
Net assets (liabilities)		
Trading contracts[1]	$ (13)	$ (6)
Non-trading contracts		
Derivatives designated as hedges	(191)	(143)
Other derivatives	960	968
Net assets from price risk management activities[2]	$ 756	$ 819

(1) Trading contracts are derivative contracts that historically have been entered into for purposes of generating a profit or benefiting from movements in market prices.

(2) Net assets from price risk management activities include current and non-current assets and current and non-current liabilities from price risk management activities on the balance sheet.

As of June 30, 2003, other derivatives include $960 million of derivative contracts associated with our power restructuring activities at our Eagle Point Cogeneration and our Capitol District Energy Center Cogeneration Associates facilities. For a further discussion of our power restructuring activities, see our 2002 Form 10-K.

9. Inventory

	June 30, 2003	December 31, 2002
	(In millions)	
Current		
Materials and supplies and other[1]	$63	$62
Non-current		
Turbines[2]	20	20
Total inventory	$83	$82

(1) As a result of El Paso's intent to dispose of our petroleum and chemical assets, inventory balances totalling $435 million and $635 million as of June 30, 2003 and December 31, 2002, have been reclassified as assets of discontinued operations (see Note 6).

(2) We record these amounts as other non-current assets in our balance sheet.

10. Debt and Other Credit Facilities

We had $560 million and $369 million of current maturities of long-term debt at June 30, 2003, and December 31, 2002.

Credit Facilities

In April 2003, El Paso removed us as a borrower under the $1 billion 3-year revolving credit and competitive advance facility, and as such, we are no longer jointly and severally liable for any amounts outstanding under that facility. In addition, El Paso entered into a new $3 billion revolving credit facility, with a $1.5 billion letter of credit sublimit, which matures on June 30, 2005. This facility replaces its previous $3 billion 364-day revolving credit facility. In addition, approximately $1 billion of other financing arrangements were amended to conform their obligations to the new $3 billion revolving credit facility. The $3 billion revolving credit facility and these other financing arrangements are collateralized, along with other assets of El Paso, including our equity in ANR Pipeline Company (ANR), Wyoming Interstate Company Ltd. (WIC), ANR Storage Company and our equity in the companies that own the assets that collateralize the Clydesdale financing arrangement discussed below.

As of June 30, 2003, El Paso maintained a $1 billion revolving credit facility, which expired on August 4, 2003.

Long-Term Debt Obligations

During 2003, we have entered into and retired several debt financing obligations:

Date	Company	Type	Interest Rate	Principal	Net Proceeds[1]/ Payments	Due Date
				(In millions)		
Issuance						
March	ANR	Senior notes	8.875%	$300	$288	2010
Retirements						
January	El Paso CGP	Long-term debt	Various	$ 57	$ 57	
February	El Paso CGP	Long-term debt	4.49%	240	240	
		Retirements through June 30, 2003		297	297	
July	El Paso CGP	Notes	Floating rate	200	200	
August	El Paso CGP	Senior debentures	9.75%	102	102	
				$599	$599	

(1) Net proceeds were primarily used to repay maturing long-term debt, redeem preferred interests of consolidated subsidiaries, repay short-term borrowings and other financing obligations and for other general corporate and investment purposes.

Restrictive Covenants

We have entered into debt instruments and guaranty agreements that contain covenants such as limitations on debt levels, limitations on liens securing debt and guarantees, limitations on mergers and on sales of assets, capitalization requirements and dividend limitations. A breach of any of these covenants could accelerate our debt and other financial obligations and that of our subsidiaries.

One of the most significant debt covenants is that we must maintain a minimum net worth of $1.2 billion. If breached, the amounts guaranteed by the guaranty agreement could be accelerated. The guaranty agreement also has a $30 million cross-acceleration provision.

In addition, we have indentures associated with our public debt that contain cross-acceleration provisions in the event of defaults greater than $5 million.

As part of El Paso's $3 billion revolving credit facility, our subsidiaries, ANR and, upon the maturity of El Paso's Clydesdale financing transaction, Colorado Interstate Gas Company (CIG), cannot incur incremental debt if the incurrence of this incremental debt would cause their debt to EBITDA ratio (as defined in El Paso's new revolving credit facility agreement) for that particular company to exceed 5 to 1. Additionally, the proceeds from the issuance of debt by the pipeline company borrowers can only be used for maintenance and expansion capital expenditures or investments in other FERC-regulated assets, to fund working capital requirements, or to refinance existing debt.

As of June 30, 2003, we were in compliance with these covenants.

Other Financing Arrangements

The equity in some of our assets, along with other El Paso assets, collateralize a financing arrangement established by El Paso referred to as Clydesdale. In April 2003, El Paso restructured the Clydesdale financing arrangement into a new term loan that amortizes in equal quarterly amounts of $100 million over the next two years, and guaranteed the third party equity. These actions resulted in the consolidation of the term loan by El Paso in the second quarter of 2003. The term loan remains collateralized by the assets currently supporting the Clydesdale transaction, consisting of a production payment from us, various natural gas and oil properties and our equity in CIG. El Paso repaid $100 million of this term loan in May 2003. As of June 30, 2003, the balance owed to third parties under the Clydesdale financing arrangement was $643 million. In August 2003, El Paso made a quarterly principal payment of $100 million on this term loan.

11. Commitments and Contingencies

Legal Proceedings

Grynberg. In 1997, a number of our subsidiaries were named defendants in actions brought by Jack Grynberg on behalf of the U.S. Government under the False Claims Act. Generally, these complaints allege an industry-wide conspiracy to underreport the heating value as well as the volumes of the natural gas produced from federal and Native American lands, which deprived the U.S. Government of royalties. The plaintiff in this case seeks royalties that he contends the government should have received had the volume and heating value of natural gas produced from royalty properties been differently measured, analyzed, calculated and reported, together with interest, treble damages, civil penalties, expenses and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. These matters have been consolidated for pretrial purposes (In re: Natural Gas Royalties *Qui Tam* Litigation, U.S. District Court for the District of Wyoming, filed June 1997). In May 2001, the court denied the defendants' motions to dismiss. Discovery is proceeding. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Will Price (formerly Quinque). 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. Quinque has been dropped as a plaintiff and Will Price has been added. This class action complaint alleges that the defendants mismeasured natural gas volumes and heating content of natural gas on non-federal and non-Native American lands. The plaintiff in this case seeks certification of a nationwide class of natural gas working interest owners and natural gas royalty owners to recover royalties that the plaintiff contends these owners should have received had the volume and heating value of natural gas produced from their properties been differently measured, analyzed, calculated and reported, together with prejudgment and postjudgment interest, punitive damages, treble damages, attorney's fees, costs and expenses, and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. Plaintiffs' motion for class certification was denied on April 10, 2003. Plaintiffs' motion to file another amended petition to narrow the proposed class to royalty owners in wells in Kansas, Wyoming and Colorado was granted on July 28, 2003. Our costs and legal exposure related to this lawsuit are not currently determinable.

MTBE. In compliance with the 1990 amendments to the Clean Air Act, we use the gasoline additive, methyl tertiary-butyl ether (MTBE), in some of our gasoline. We also produce, buy, sell and distribute MTBE. A number of lawsuits have been filed throughout the U.S. regarding MTBE's potential impact on water supplies. We are currently one of several defendants in one such lawsuit in New York. The plaintiffs seek remediation of their groundwater and prevention of future contamination, compensatory damages for the costs of replacement water and for diminished property values, as well as punitive damages, attorney's fees, court costs, and, in some cases, future medical monitoring. Our costs and legal exposure related to this lawsuit and claims are not currently determinable.

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

For each of our outstanding legal matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we establish the necessary accruals. As of June 30, 2003, we had approximately $31 million accrued for all outstanding legal matters. Approximately $5 million of the accrual was related to discontinued petroleum operations.

Environmental Matters

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. As of June 30, 2003, we had accrued approximately $150 million, including approximately $149 million for expected remediation costs at current and former operated sites and associated onsite, offsite and groundwater technical studies, and approximately $1 million for related environmental legal costs, which we anticipate incurring through 2027. Approximately $45 million of the accrual was related to discontinued petroleum operations.

The high end of our reserve estimate was approximately $236 million and the low end was approximately $139 million. The estimate of $139 million represents a combination of two estimating methodologies. First, where the most likely outcome can be reasonably estimated, that cost has been accrued ($44 million). Second, where the more likely outcome cannot be estimated, a range of costs is established ($95 million to $192 million) and the lower end of the range has been accrued. By type of site, our reserves are based on the following estimates of reasonably possible outcomes.

Sites	June 30, 2003 Low	High
	(In millions)	
Operating	$105	$164
Non-operating	29	64
Superfund	5	8

Below is a reconciliation of our accrued liability as of June 30, 2003 (in millions):

Balance as of January 1, 2003	$171
Additions/adjustments for remediation activities	(12)
Payments for remediation activities	(13)
Other changes, net	4
Balance as of June 30, 2003	$150

In addition, we expect to make capital expenditures for environmental matters of approximately $199 million in the aggregate for the years 2003 through 2008. These expenditures primarily relate to compliance with clean air regulations. For the remainder of 2003, we estimate that our total remediation expenditures will be approximately $27 million.

Coastal Eagle Point. From May 1999 to March 2001, our Coastal Eagle Point Oil Company received several Administrative Orders and Notices of Civil Administrative Penalty Assessment from the New Jersey Department of Environmental Protection (DEP). All of the assessments are related to alleged noncompliance with the New Jersey Air Pollution Control Act (the Act) pertaining to excess emissions from the first quarter 1998 through the fourth quarter 2000 reported by our Eagle Point refinery in Westville, New Jersey. The DEP has assessed penalties totaling approximately $1.3 million for these alleged violations. The DEP has indicated a willingness to accept a reduced penalty and a supplemental environmental project. Our Eagle Point refinery has been granted an administrative hearing on issues raised by the assessments. Subsequently DEP assessed an additional $118,000 in penalties for alleged noncompliance with the Act. On February 24, 2003, EPA Region 2 issued a Compliance Order based on a 1999 EPA inspection of the refinery's leak detection and repair (LDAR) program. Alleged violations include failure to monitor all components, and failure to timely repair leaking components. During an August 2000 follow-up inspection, the EPA confirmed our Eagle Point refinery had improved its implementation of the program. The Compliance Order requires documentation of compliance with the program. We met with the EPA and DEP in March 2003 to discuss the Order and the possibility for a global settlement pursuant to the EPA's refinery enforcement initiative. Global settlements involving other refiners have included civil penalties and addressed LDAR as well as new source review, the benzene standard, and the standard for combustion of refinery fuel gas. On April 25, 2003, our Eagle Point refinery sent a letter to the EPA committing to global settlement discussions, which are ongoing. Our Eagle Point refinery expects to resolve both the DEP assessments and the EPA refinery initiative issues.

CERCLA Matters. We 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 27 active sites under the Comprehensive Environmental Response, Compensation and Liability Act

(CERCLA) or state equivalents. We have sought to resolve our liability as a PRP at these sites through indemnification by third parties and settlements which provide for payment of our allocable share of remediation costs. As of June 30, 2003, we have estimated our share of the remediation costs at these sites to be between $5 million and $8 million. Since the clean-up costs are estimates and are subject to revision as more information becomes available about the extent of remediation required, and because in some cases we have asserted a defense to any liability, our estimates could change. Moreover, liability under the federal CERCLA statute is joint and several, meaning that we could be required to pay in excess of our pro rata share of remediation costs. Our understanding of the financial strength of other PRPs has been considered, where appropriate, in estimating our liabilities. Accruals for these issues are included in the previously indicated estimates for operating sites.

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 our current reserves are adequate.

Rates and Regulatory Matters

Marketing Affiliate NOPR. In September 2001, the FERC issued a Notice of Proposed Rulemaking (NOPR). The NOPR proposes to apply the standards of conduct governing the relationship between interstate pipelines and marketing affiliates to all energy affiliates. The proposed regulations, if adopted by the FERC, would dictate how all our energy affiliates conduct business and interact with our interstate pipelines. We have filed comments with the FERC addressing our concerns with the proposed rules, participated in a public conference and filed additional comments. At this time, we cannot predict the outcome of the NOPR, but adoption of the regulations in their proposed form would, at a minimum, place additional administrative and operational burdens on us.

Negotiated Rate Policy. In July 2002, the FERC issued a Notice of Inquiry (NOI) that sought comments regarding its 1996 policy of permitting pipelines to enter into negotiated rate transactions. We have entered into those transactions over the years, and the FERC is now reviewing whether negotiated rates should be capped, whether or not the "recourse rate" (a cost-of-service based rate) continues to safeguard against a pipeline exercising market power and other issues related to negotiated rate programs. El Paso's pipelines and others filed comments on the NOI.

In July 2003, the FERC issued modifications to its negotiated rate policy applicable to interstate natural gas pipelines. The new policy has two primary changes. First, the FERC will no longer permit the pricing of negotiated rates based on natural gas commodity price indices, although it will permit current contracts negotiated on that basis to continue until the end of the applicable contract period. Second, the FERC is imposing new filing requirements on pipelines to ensure the transparency of negotiated rate transactions.

Interim Rule on Cash Management. In August 2002, the FERC issued a NOPR proposing, *inter alia*, that all cash management or money pool arrangements between a FERC-regulated subsidiary and its non-FERC regulated parent be in writing and that, as a condition of participating in such an arrangement, the FERC-regulated entity maintain a minimum proprietary capital balance of 30 percent and both it and its parent maintain investment grade credit ratings. After receiving written comments and hearing industry participants' concerns at a public conference in September 2002, the FERC issued an Interim Rule on Cash Management on June 26, 2003, which did not adopt the proposed limitations on entry into or participating in cash management programs. Instead, the Interim Rule requires natural gas companies to maintain up-to-date documentation authorizing the establishment of the cash management programs in which they participate and supporting all deposits into, borrowings and interest from, and interest expense paid to such programs.

The Interim Rule also seeks comments on a proposed reporting requirement that a FERC-regulated entity file cash management agreements and any changes thereto within ten days and that it notify the Commission within five days when its proprietary capital ratio falls below 30 percent (i.e., its long-term debt-to-equity ratio rises above 70 percent) and when it subsequently returns to or exceeds 30 percent. We filed comments on the Interim Rule on August 7, 2003.

Pipeline Safety Notice of Proposed Rulemaking. In January 2003, the U.S. Department of Transportation issued a NOPR proposing to establish a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the notice refers to as "high consequence areas." The proposed rule resulted from the enactment of the Pipeline Safety Improvement Act of 2002, a new bill signed into law in December 2002. Comments on the NOPR were filed on April 30, 2003. At this time, we cannot predict the outcome of this rulemaking.

FERC Inquiry. On February 26, 2003, El Paso received a letter from the Office of the Chief Accountant at the FERC requesting details of its announcement of 2003 asset sales and plans for us and our pipeline affiliates to issue a combined $700 million of long-term notes. The letter requested that El Paso explain how it intended to use the proceeds from the issuance of the notes and if the notes will be included in the two regulated companies' capital structure for rate-setting purposes. Our response to the FERC was filed on March 12, 2003. On April 2, 2003, we received an additional request for information, to which we fully responded on April 15, 2003.

While the outcome of our outstanding legal matters, environmental matters, and rates and regulatory matters cannot be predicted with certainty, based on current information and our existing accruals, we do not expect the ultimate resolution of these matters to have a material adverse effect on our financial position, operating results or cash flows. However, it is possible that new information or future developments could require us to reassess our potential exposure related to these matters. It is also possible that these matters could impact our debt rating and credit rating. Further, for environmental matters, it is also possible that other developments, such as increasingly strict environmental laws and regulations and claims for damages to property, employees, other persons and the environment resulting from our current or past operations, could result in substantial costs and liabilities in the future. As new information regarding our outstanding legal matters, environmental matters and rates and regulatory matters becomes available, or relevant developments occur, we will review our accruals and make any appropriate adjustments. The impact of these changes may have a material effect on our results of operations, our financial position, and on our cash flows in the period the event occurs.

Other

Economic Conditions in the Dominican Republic. Recent developments in the economic and financial situation in the Dominican Republic have led to a devaluation of the Dominican peso of approximately 77 percent versus the U.S. dollar since January 2003 (through June 30, 2003) and an increase in the local inflation rate of approximately 25 percent for the same period. A stand-by agreement with the IMF is expected to receive final approval of the IMF Board in August. The Dominican government maintains that the accord, which should hopefully lead to some $1.2 billion in disbursements from multilaterals over the next 24 months, will serve to restore consumer and investor confidence, stabilize the exchange rate and pave the way to economic recovery. The initial disbursement of the funds is not anticipated until early September of 2003.

We have investments in power projects in the Dominican Republic with an aggregate exposure, including financial guarantees, of approximately $104 million. We own a 48.33 percent interest in a 67 megawatt heavy fuel oil fired project known as the CEPP project. We also own a 24.99 percent interest in a 513 megawatt power generating complex known as Itabo. As a consequence of economic conditions described above and due to their inability to pass through higher energy prices to their consumers, the local distribution companies that purchase the electrical output of these facilities have been delinquent in their payments to CEPP and Itabo, as well as the other generating facilities in the Dominican Republic since April 2003. The failure to pay generators has resulted in the inability of the generators to purchase fuel required for the production of energy which has caused significant energy shortfalls in the country. We currently believe that the economic difficulties in the Dominican Republic will not have a material adverse effect on our investments, but we will continue to monitor those conditions and are working with the government and the local distribution companies to resolve these issues.

12. Segment Information

We segregate our business activities into four operating segments: Pipelines, Production, Field Services and Merchant Energy. 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, operational and marketing strategies. We reclassified our historical coal mining operation in the second quarter of 2002 and our petroleum and chemical operations in the second quarter of 2003 from our Merchant Energy segment to discontinued operations in our financial statements. Merchant Energy's operating results for all periods presented reflect this change.

We use earnings before interest expense and income taxes (EBIT) to assess the operating results and effectiveness of our business segments. We define EBIT as net income (loss) adjusted for (i) items that do not impact our income (loss) from continuing operations, such as extraordinary items, discontinued operations and the impact of accounting changes, (ii) income taxes, (iii) interest and debt expense and (iv) distributions on preferred interests of consolidated subsidiaries. We exclude interest and debt expense and distributions on preferred interests of consolidated subsidiaries so that investors may evaluate our operating results without regard to our financing methods or capital structure. Our business operations consist of both consolidated businesses as well as substantial investments in unconsolidated affiliates. As a result, we believe EBIT, which includes the results of both these consolidated and unconsolidated operations, is useful to our investors because it allows them to more effectively evaluate the performance of all of our businesses and investments. This measurement may not be comparable to measurements used by other companies and should not be used as a substitute for net income or other performance measures such as operating income or operating cash flow. The reconciliations of EBIT to income (loss) from continuing operations are presented below:

	Quarters Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
	(In millions)			
Total EBIT	$165	$ 136	$478	$ 749
Interest and debt expense	(100)	(104)	(199)	(207)
Affiliated interest expense, net	(7)	(2)	(14)	(6)
Distributions on preferred interests of consolidated subsidiaries	(7)	(11)	(14)	(21)
Income taxes	(77)	(5)	(89)	(167)
Income (loss) from continuing operations	$(26)	$ 14	$162	$ 348

The following tables reflect our segment results as of and for the periods ended June 30 (in millions):

	Quarter Ended June 30,					
	Pipelines	Production	Field Services	Merchant Energy	Corporate & Other[(1)]	Total
2003						
Revenues from external customers	$209	$221	$ 87	$ 67	$ 26	$ 610
Intersegment revenues	—	33	12	(7)	(38)	—
Operating income (loss)	$ 89	$ 83	$ 27	$ 20	$ (6)	$ 213
Earnings (losses) from unconsolidated affiliates	16	(1)	(79)	10	—	(54)
Other income	1	—	—	4	4	9
Other expense	—	—	—	(3)	—	(3)
EBIT	$106	$ 82	$(52)	$ 31	$ (2)	$ 165
2002						
Revenues from external customers	$211	$298	$103	$107[(2)]	$ 39	$ 758
Intersegment revenues	13	32	10	6[(2)]	(61)	—
Operating income (loss)	$ 85	$(76)	$ 27	$ 70	$(13)	$ 93
Earnings (losses) from unconsolidated affiliates	24	(2)	—	14	—	36
Other income	6	—	—	8	1	15
Other expense	(1)	—	—	(3)	(4)	(8)
EBIT	$114	$(78)	$ 27	$ 89	$(16)	$ 136

	Six Months Ended June 30,					
	Pipelines	Production	Field Services	Merchant Energy	Corporate & Other[(1)]	Total
2003						
Revenues from external customers	$501	$470	$201	$ 124	$ 52	$1,348
Intersegment revenues	—	57	25	(8)	(74)	—
Operating income (loss)	$242	$180	$ 38	$ 29	$ (8)	$ 481
Earnings (losses) from unconsolidated affiliates	39	1	(79)	24	—	(15)
Other income	2	1	—	8	7	18
Other expense	(4)	—	—	(2)	—	(6)
EBIT	$279	$182	$(41)	$ 59	$ (1)	$ 478
2002						
Revenues from external customers	$468	$665	$193	$1,063[(2)]	$ 66	$2,455
Intersegment revenues	20	54	21	10[(2)]	(105)	—
Operating income (loss)	$228	$ 82	$ 32	$ 471	$ (26)	$ 787
Earnings from unconsolidated affiliates	56	—	—	28	—	84
Other income	9	—	—	15	4	28
Other expense	(1)	—	—	(144)	(5)	(150)
EBIT	$292	$ 82	$ 32	$ 370	$ (27)	$ 749

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

(2) Merchant Energy revenues were restated on July 1, 2002 due to the adoption of a consensus reached on Emerging Issues Task Force (EITF) Issue No. 02-3, *Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities,* which requires us to report all physical sales of energy commodities in our energy trading activities on a net basis as a component of revenues. See our 2002 Form 10-K regarding the adoption of EITF Issue No. 02-3.

Total assets by segment are presented below:

	June 30, 2003	December 31, 2002
	(In millions)	
Pipelines	$ 5,269	$ 5,175
Production	4,625	4,370
Field Services	237	417
Merchant Energy	2,375	2,446
Corporate and other	698	760
Total segment assets	13,204	13,168
Discontinued operations	1,711	4,065
Total consolidated assets	$14,915	$17,233

13. Investments in Unconsolidated Affiliates and Related Party Transactions

We hold investments in affiliates which we account for using the equity method of accounting. Summarized financial information of our proportionate share of unconsolidated affiliates below includes affiliates in which we hold an interest of 50 percent or less, as well as those in which we hold a greater than 50 percent interest. Our proportional share of the net income of the unconsolidated affiliates in which we hold a greater than 50 percent interest was $2 million and $6 million for the quarters ended, and $9 million and $18 million for the six months ended, June 30, 2003 and 2002.

	Quarters Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
	(In millions)			
Operating results data:				
Operating revenues	$206	$220	$399	$358
Operating expenses	148	146	281	230
Income from continuing operations	19	32	53	73
Net income	19	32	53	73

Our income statement reflects our earnings (losses) from unconsolidated affiliates. This amount includes income or losses directly attributable to the net income or loss of our equity investments as well as impairments and other adjustments to income we record. For the quarter ended June 30, 2003, we recorded impairment charges of $80 million related to our investments in Dauphin Island Gathering Partners and Mobile Bay Processing Partners in the Field Services segment due to our anticipation of incurring a loss from selling our interests in these investments.

Related Party Transactions

We participate in El Paso's cash management program which matches short-term cash surpluses and needs of its participating affiliates, thus minimizing total borrowing from outside sources. See Note 11 for further discussion on the FERC's Interim Rule on Cash Management. As of June 30, 2003, and December 31, 2002, we had borrowed $1,602 million and $2,374 million. The market rate of interest as of June 30, 2003, and December 31, 2002, was 1.3% and 1.5%. In addition, we had a demand note receivable with El Paso of $231 million and $199 million at June 30, 2003, and December 31, 2002. The interest rate for this demand note receivable was 1.8% at June 30, 2003, and 2.2% at December 31, 2002.

At June 30, 2003, and December 31, 2002, we had current accounts and notes receivable from related parties of $300 million and $322 million. These balances were incurred in the normal course of our business. In addition, we had a non-current note receivable from a related party of $235 million and $126 million included in other non-current assets at June 30, 2003, and at December 31, 2002.

At June 30, 2003, and December 31, 2002, we had other accounts payable to related parties of $96 million and $87 million. These balances were incurred in the normal course of business.

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

Also, in March 2002, we sold natural gas and oil properties to El Paso. Net proceeds from these sales were $404 million, and we did not recognize a gain or loss on the properties sold. The proceeds exceeded the net book value by $32 million, and we recorded these proceeds as an increase to paid-in-capital.

We enter into a number of transactions with our unconsolidated affiliates in the ordinary course of conducting our business. The following table shows revenues, income and expenses incurred between us and our unconsolidated affiliates and El Paso's subsidiaries for the periods ended June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
		(In millions)		
Revenues	$337	$337	$580	$816
Cost of sales	29	57	67	106
Charges from affiliates	102	93	205	203
Other income	1	2	3	3

14. New Accounting Pronouncements Issued But Not Yet Adopted

As of June 30, 2003, there were a number of accounting standards and interpretations that had been issued, but not yet adopted by us. Below is a discussion of the more significant standards that could impact us.

Amendment of Statement 133 Derivative Instruments and Hedging Activities

In April 2003, the Financial Accounting Standards Board (FASB) issued SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities.* This statement amends SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* to incorporate the interpretations of the Derivatives Implementation Group (DIG) and also makes several minor modifications to the definition of a derivative as it was defined in SFAS No. 133. SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003. We do not believe there will be any initial impact of adopting this standard.

Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity

In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity.* This statement provides guidance on the classification of financial instruments as equity, as liabilities, or as both liabilities and equity. The provisions of SFAS No. 150 are effective for all financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning July 1, 2003. Based on our preliminary assessment of the standard, we believe its provisions will require us to reclassify our Coastal Finance I preferred interests (currently classified as preferred interests of consolidated subsidiaries) as liabilities beginning July 1, 2003. As of June 30, 2003, the Coastal Finance I balance was $300 million.

Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51

In January 2003, the FASB issued FIN No. 46, *Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51.* This interpretation defines a variable interest entity as a legal entity whose equity owners do not have sufficient equity at risk and/or a controlling financial interest in the entity. This standard requires a company to consolidate a variable interest entity if it is allocated a majority of the entity's losses and/or returns, including fees paid by the entity. The provisions of FIN No. 46 are effective for all variable interest entities created after January 31, 2003, and are effective on July 1, 2003, for all variable interest entities created before January 31, 2003.

Upon adoption of this standard on July 1, 2003, we will be required to consolidate the preferred equity holder of one of our consolidated subsidiaries, Coastal Securities Company Limited. The impact of this consolidation will be an increase in long-term debt and a decrease in preferred interests in consolidated subsidiaries by $100 million.

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

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

Segment Results

We use earnings before interest expense and income taxes (EBIT) to assess the operating results and effectiveness of our business segments. We define EBIT as net income (loss) adjusted for (i) items that do not impact our income (loss) from continuing operations, such as extraordinary items, discontinued operations and the impact of accounting changes, (ii) income taxes, (iii) interest and debt expense and (iv) distributions on preferred interests of consolidated subsidiaries. We exclude interest and debt expense and distributions on preferred interests of consolidated subsidiaries so that investors may evaluate our operating results without regard to our financing methods or capital structure. Our business operations consist of both consolidated businesses as well as substantial investments in unconsolidated affiliates. As a result, we believe EBIT, which includes the results of both these consolidated and unconsolidated operations, is useful to our investors because it allows them to more effectively evaluate the performance of all of our businesses and investments. This measurement may not be comparable to measurements used by other companies and should not be used as a substitute for net income or other performance measures such as operating income or operating cash flow. The following is a reconciliation of our operating income to our EBIT and our EBIT to our net income (loss) for the periods ended June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
	(In millions)			
Operating revenues	$ 610	$ 758	$ 1,348	$ 2,455
Operating expenses	(397)	(665)	(867)	(1,668)
Operating income	213	93	481	787
Earnings (losses) from unconsolidated affiliates	(54)	36	(15)	84
Other income	9	15	18	28
Other expenses	(3)	(8)	(6)	(150)
EBIT	165	136	478	749
Interest and debt expense	(100)	(104)	(199)	(207)
Affiliated interest expense, net	(7)	(2)	(14)	(6)
Distributions on preferred interests of consolidated subsidiaries	(7)	(11)	(14)	(21)
Income taxes	(77)	(5)	(89)	(167)
Income (loss) from continuing operations	(26)	14	162	348
Discontinued operations, net of income taxes	(916)	(116)	(1,138)	(56)
Cumulative effect of accounting changes, net of income taxes	—	14	(21)	14
Net income (loss)	$(942)	$ (88)	$ (997)	$ 306

Overview of Results of Operations

Below are our results of operations (as measured by EBIT) by segment. Our four operating segments — Pipelines, Production, Field Services and Merchant Energy — provide a variety of energy products and services. They are managed separately as each business unit requires different technology, operational and marketing strategies. We reclassified our historical coal mining operation in the second quarter of 2002 and our petroleum and chemical operations in the second quarter of 2003 from our Merchant Energy segment to discontinued operations in our financial statements. Merchant Energy's results for all periods presented reflect this change. For a further discussion of charges and other income and expense items impacting the results below, see Item 1, Notes 1 through 6 and 13.

	Quarter Ended June 30,		Six Months Ended June 30,	
EBIT by Segment	2003	2002	2003	2002
	(In millions)			
Pipelines	$106	$114	$279	$292
Production	82	(78)	182	82
Field Services	(52)	27	(41)	32
Merchant Energy	31	89	59	370
Segment EBIT	167	152	479	776
Corporate and other	(2)	(16)	(1)	(27)
Consolidated EBIT	$165	$136	$478	$749

Pipelines

Our Pipelines segment holds our interstate transmission businesses. For a further discussion of the business activities of our Pipelines segment, see our 2002 Form 10-K. Results of our Pipelines segment operations were as follows for the periods ended June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
Pipeline Segment Results	2003	2002	2003	2002
	(In millions, except volume amounts)			
Operating revenues	$ 209	$ 224	$ 501	$ 488
Operating expenses	(120)	(139)	(259)	(260)
Operating income	89	85	242	228
Other income	17	29	37	64
EBIT	$ 106	$ 114	$ 279	$ 292
Throughput volumes (BBtu/d)[1]	7,520	7,419	8,670	8,275

(1) Throughput volumes for the quarter and six months ended June 30, 2002, exclude 208 BBtu/d and 216 BBtu/d related to our equity interest in the Alliance pipeline system which was sold in November 2002 and March 2003. Throughput volumes also exclude volumes transported between entities within the Pipelines segment. Prior period volumes have been restated to reflect current year presentations which includes billable transportation throughput volume for storage withdrawal.

Second Quarter 2003 Compared to Second Quarter 2002

Operating revenues for the quarter ended June 30, 2003, were $15 million lower than the same period in 2002. The decrease was primarily due to lower revenues of $27 million due to CIG's sale of the Panhandle field and other production properties in July 2002 and $7 million of lower storage revenues due to the timing of revenues realized in 2003 versus 2002 and lower contracted volumes partially offset by higher prices in 2003. These decreases were offset by a $6 million increase due to completed system expansion projects and new transportation contracts, $5 million from higher realized prices in 2003 on the resale of natural gas purchased from the Dakota gasification facility, the impact of higher prices in 2003 on natural gas recovered in excess of amounts used in operations of $4 million, an increase of $2 million in liquid revenues resulting from higher liquids prices and a $2 million increase in reservation revenues due to an increase in contracted volumes on the WIC system.

Operating expenses for the quarter ended June 30, 2003, were $19 million lower than the same period in 2002. The decrease was due to lower operating expenses of $14 million due to CIG's sale of the Panhandle field and other production properties in July 2002, additional accruals in the second quarter of 2002 of $10 million on estimated liabilities to assess and remediate our environmental exposure due to an ongoing evaluation of the exposure at our facilities and a $9 million gain on the buyout of a gas purchase contract related to the sale of CIG's Table Rock sulfur extraction facility and the sale of non-pipeline assets in 2003. These decreases were offset by $7 million of favorable corporate overhead allocations adjustments received in the second quarter of 2002, volume adjustments related to one of CIG's storage fields of $5 million in 2003 and an increase of $4 million from higher prices on natural gas purchases from the Dakota gasification facility.

Other income for the quarter ended June 30, 2003, was $12 million lower than the same period in 2002. The decrease was due to lower equity earnings of $6 million due to the sale of our interests in the Alliance pipeline system completed in the first quarter of 2003 and the favorable resolution of uncertainties associated with the 2002 sale of our interest in the Iroquois pipeline system of $4 million.

Six Months Ended 2003 Compared to Six Months Ended 2002

Operating revenues for the six months ended June 30, 2003, were $13 million higher than the same period in 2002. This increase was due to the impact of higher prices in 2003 on natural gas recovered in excess of amounts used in operations of $19 million, $14 million from higher realized prices in 2003 on the resale of natural gas purchased from the Dakota gasification facility and a $10 million increase due to completed system expansion projects and new transportation contracts. Also contributing to the increase was a $6 million increase in liquid revenues resulting from higher liquid prices, a $5 million increase in reservation revenues due to an increase in contracted volumes on the WIC system and a $5 million increase in transportation revenues due to higher throughput volumes in 2003 as a result of colder winter weather. These increases were partially offset by a $47 million decrease in revenues due to CIG's sale of its Panhandle field and other production properties in July 2002.

Operating expenses for the six months ended June 30, 2003, were $1 million lower than the same period in 2002. The decrease was due to a $26 million decrease in operating costs resulting from CIG's sale of its Panhandle field and other production properties in July 2002, additional accruals in the second quarter of 2002 of $10 million on estimated liabilities to assess and remediate our environmental exposure due to an ongoing evaluation of the exposure at our facilities and a $9 million gain on the buyout of a gas purchase contract related to the sale of CIG's Table Rock sulfur extraction facility and the sale of non-pipeline assets in 2003. These decreases were offset by a $13 million from higher prices on natural gas purchased at the Dakota gasification facility, an $11 million gain on the sale of pipeline expansion rights in February 2002, $7 million of favorable corporate overhead allocations adjustments received in the second quarter of 2002, lower benefit costs in 2002 of $6 million and volume adjustments related to one of CIG's storage fields of $5 million in 2003.

Other income for the six months ended June 30, 2003, was $27 million lower than the same period in 2002. The decrease was due to lower equity earnings of $11 million due to the sale of our interest in the Alliance Pipeline system completed in the first quarter of 2003, the favorable resolution of uncertainties in 2002 of $8 million associated with the sale of our interests in the Iroquois and Empire State pipeline systems and the Gulfstream pipeline project in 2001 and a charge of $4 million related to the partial termination of a hedging obligation regarding Blue Lake Gas Storage Company in which we have a 75 percent ownership interest.

Production

Our Production segment conducts our natural gas and oil exploration and production activities. Our operating results are driven by a variety of factors including our ability to locate and develop economic natural gas and oil reserves, extract those reserves with minimal production costs, sell the products at attractive prices and operate at the lowest total cost level possible.

As further described in our 2002 Form 10-K, Production has historically engaged in hedging activities on its natural gas and oil production to stabilize cash flows and to reduce the risk of downward commodity price movements on its sales. As of June 30, 2003, we have hedged approximately 42 million MMBtu's of our remaining anticipated natural gas production for 2003 at a NYMEX Henry Hub price of $4.36 per MMBtu before regional price differentials and transportation costs.

Our depletion rate is determined under the full cost method of accounting. We expect a higher depletion rate in future periods as a result of higher finding and development costs experienced in the first half of 2003, coupled with a lower reserve base due to asset sales. For the third quarter of 2003, we expect our domestic unit of production depletion rate to be approximately $2.17 per Mcfe.

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

Production Segment Results	Quarter Ended June 30, 2003	Quarter Ended June 30, 2002	Six Months Ended June 30, 2003	Six Months Ended June 30, 2002
	(In millions, except volumes and prices)			
Operating Revenues:				
Natural gas	$ 215	$ 279	$ 439	$ 626
Oil, condensate and liquids	32	47	79	86
Other	7	4	9	7
Total operating revenues	254	330	527	719
Transportation and net product costs	(13)	(12)	(26)	(25)
Total operating margin	241	318	501	694
Operating expenses[(1)]	(158)	(394)	(321)	(612)
Operating income	83	(76)	180	82
Other income (expense)	(1)	(2)	2	—
EBIT	$ 82	$ (78)	$ 182	$ 82
Volumes and prices				
Natural gas				
Volumes (MMcf)	43,747	65,465	86,058	148,731
Average realized prices with hedges ($/Mcf)[(2)]	$ 4.91	$ 4.27	$ 5.10	$ 4.21
Average realized prices without hedges ($/Mcf)[(2)]	$ 5.22	$ 3.43	$ 5.91	$ 2.79
Average transportation costs ($/Mcf)	$ 0.25	$ 0.17	$ 0.23	$ 0.14
Oil, condensate and liquids				
Volumes (MBbls)	1,255	1,993	2,978	4,687
Average realized prices with hedges ($/Bbl)[(2)]	$ 25.19	$ 23.63	$ 26.40	$ 18.37
Average realized prices without hedges ($/Bbl)[(2)]	$ 25.19	$ 22.92	$ 26.40	$ 18.07
Average transportation costs ($/Bbl)	$ 0.81	$ 0.44	$ 0.85	$ 0.78

(1) Include production costs, depletion, depreciation and amortization, ceiling test charges, asset impairments, gain and loss on long-lived assets, corporate overhead, general and administrative expenses and severance and other taxes.

(2) Prices are stated before transportation costs.

Second Quarter 2003 Compared to Second Quarter 2002

Operating revenues for the quarter ended June 30, 2003, were $76 million lower than the same period in 2002. Our natural gas revenues, including the impact of hedges, were $64 million lower in the second quarter of 2003. Our 2003 natural gas production volumes were lower by 33 percent, resulting in a $92 million decrease in revenues, from the same period in 2002. Realized natural gas prices rose in 2003 by 15 percent, resulting in a $28 million increase in revenues, when compared to the same period in 2002. The overall decline in natural gas volumes was due to sales of production properties in Colorado, New Mexico, Utah, Texas and western Canada as well as normal production declines and mechanical failures on certain producing wells. Our oil, condensate and liquids revenues, including the impact of hedges, were $15 million lower in the second quarter of 2003. Our 2003 oil, condensate and liquids volumes decreased by 37 percent, resulting in a $17 million decrease in revenues, from the same period in 2002. Realized oil, condensate and liquids prices rose in 2003 by 7 percent, resulting in a $2 million increase in revenues, when compared to the same period in 2002. The declines in volumes were primarily due to the property sales and production declines mentioned above.

Operating expenses for the quarter ended June 30, 2003, were $236 million lower than the same period in 2002 primarily due to a second quarter of 2002 non-cash full cost ceiling test charge of $233 million incurred primarily in our Canadian full cost pool. Also contributing to the decreases were lower oilfield service costs of $19 million primarily due to asset dispositions which resulted in lower labor and production processing fees and a $5 million gain on the sales of non-full cost pool assets. Partially offsetting these decreases were higher depletion expenses of $2 million, comprised of a $34 million increase due to higher depletion rates in 2003 and costs of $3 million related to the accretion of our liability for asset retirement obligations, partially offset by a $35 million decrease due to lower production volumes in 2003. The higher depletion rate resulted from higher capitalized costs in the full cost pool coupled with a lower reserve base. In addition, these decreases were offset by higher corporate overhead allocations of $3 million, higher severance and other taxes of $11 million in 2003 and intangible asset impairments of $5 million in 2003 related to non-full cost assets in Canada. The increase in severance taxes was primarily due to tax credits taken in 2002 for qualified natural gas wells.

Six Months Ended 2003 Compared to Six Months Ended 2002

Operating revenues for the six months ended June 30, 2003, were $192 million lower than the same period in 2002. Our natural gas revenues, including the impact of hedges, were $187 million lower in 2003. Our 2003 natural gas production volumes were lower by 42 percent, resulting in a $263 million decrease in revenues, from the same period in 2002. Realized natural gas prices rose in 2003 by 21 percent, resulting in a $76 million increase in revenues, when compared to the same period in 2002. The decline in natural gas volumes was due to sales of production properties in Colorado, New Mexico, Utah, Texas and western Canada as well as normal production declines and mechanical failures on certain producing wells. Our oil, condensate and liquids revenues, including the impact of hedges, were $7 million lower in 2003. Our 2003 oil, condensate and liquids volumes decreased by 36 percent, resulting in a $31 million decrease in revenues, from the same period in 2002. Realized oil, condensate and liquids prices rose in 2003 by 44 percent, resulting in a $24 million increase in revenues, when compared to the same period in 2002. The declines in volumes were primarily due to the property sales and production declines mentioned above.

Operating expenses for the six months ended June 30, 2003, were $291 million lower than the same period in 2002 primarily due to a 2002 non-cash full cost ceiling test charge of $243 million primarily for our Canadian full cost pool. Also contributing to the decrease were lower oilfield service costs of $33 million primarily due to asset dispositions which resulted in lower labor and production processing fees, a $5 million gain on the sales of non-full cost pool assets and lower corporate overhead allocations of $2 million. Further decreasing expenses were lower depletion expenses of $33 million comprised of a $97 million decrease resulting from lower production volumes in 2003, partially offset by a $58 million increase due to higher depletion rates in 2003 and costs of $6 million related to the accretion of our liability for asset retirement obligations. The higher depletion rate resulted from higher capitalized costs in the full cost pool coupled with a lower reserve base. Partially offsetting the decreases were higher severance and other taxes of $11 million and intangible asset impairments of $14 million in 2003 on non-full cost assets in Canada. The increase in severance taxes was primarily due to tax credits taken in 2002 for qualified natural gas wells.

Field Services

Our Field Services segment conducts our midstream activities. In the second quarter of 2003, we sold our midstream assets in the Mid-Continent region. These assets primarily included our Greenwood, Hugoton, Keyes and Mocane natural gas gathering systems, our Sturgis, Mocane and Lakin processing plants and our processing arrangements at three additional processing plants. These assets generated EBIT of approximately $10 million during the year ended December 31, 2002. Our remaining assets now consist primarily of our processing facilities in the south Louisiana and Rocky Mountain regions.

As a result of our asset sales and the resulting decline in our gathering and treating activities, our EBIT has decreased significantly. For a further discussion of the business activities of our Field Services segment, see our 2002 Form 10-K. Results of our Field Services segment operations were as follows for the periods ended June 30:

Field Services Segment Results	Quarter Ended June 30, 2003	Quarter Ended June 30, 2002	Six Months Ended June 30, 2003	Six Months Ended June 30, 2002
	(In millions, except volumes and prices)			
Gathering, treating and processing gross margins[1]	$ 19	$ 33	$ 43	56
Operating income (expenses)	8	(6)	(5)	(24)
Operating income	27	27	38	32
Other expense	(79)	—	(79)	—
EBIT	$ (52)	$ 27	$ (41)	$ 32
Volume and prices				
Gathering and treating				
Volumes (BBtu/d)	125	637	163	642
Prices ($/MMBtu)	$ 0.06	$ 0.15	$ 0.16	$ 0.14
Processing				
Volumes (inlet BBtu/d)	1,748	1,713	1,726	1,761
Prices ($/MMBtu)	$ 0.12	$ 0.14	$ 0.12	$ 0.12

[1] Gross margins consist of operating revenues less cost of products sold. We believe this measurement is more meaningful for analyzing our Field Services operating results because commodity costs play such a significant role in the determination of profit from our midstream activities.

Second Quarter 2003 Compared to Second Quarter 2002

Total gross margins for the quarter ended June 30, 2003, were $14 million lower than the same period in 2002. The decrease was primarily due to lower margins of $11 million as a result of the sales of our Dragon Trail processing plant in May 2002, Natural Buttes and Ouray natural gas gathering systems in December 2002, Wyoming gathering assets in January 2003, and Mid-Continent gathering and processing assets in June 2003.

Operating expenses for the quarter ended June 30, 2003, were $14 million lower than the same period in 2002 primarily due to the asset sales discussed above, resulting in lower operating and depreciation expenses of $6 million and a net gain of $19 million from the sale of our Mid-Continent midstream assets in the second quarter of 2003. These decreases were partially offset by a $10 million gain in the second quarter of 2002 from the sale of our Dragon Trail processing plant.

Other expense for the quarter ended June 30, 2003 included $80 million in impairment charges on our Dauphin Island Gathering Partners and Mobile Bay Processing Partners investments. The impairment was recorded based on an expected loss from the anticipated sale of our interest in these investments.

Six Months Ended 2003 Compared to Six Months Ended 2002

Total gross margins for the six months ended June 30, 2003, were $13 million lower than the same period in 2002. The decrease was primarily due to lower margins of $16 million as a result of sales of our Dragon Trail processing plant in May 2002, Natural Buttes and Ouray natural gas gathering systems in December 2002, Wyoming gathering assets in January 2003, and Mid-Continent gathering and processing assets in June 2003. Partially offsetting this decrease was a $6 million increase to our south Louisiana processing margins due to higher natural gas liquids prices and change in contract terms.

Operating expenses for the six months ended June 30, 2003, were $19 million lower than the same period in 2002 primarily due to the asset sales discussed above, resulting in lower operating and depreciation expenses of $11 million and a net gain of $19 million from the sale of our Mid-Continent midstream assets in the second quarter of 2003. The decreases were partially offset by a $10 million gain in the second quarter of 2002 from the sale of our Dragon Trail processing plant.

Other expense for the six months ended June 30, 2003, included $80 million in impairment charges on our Dauphin Island Gathering Partners and Mobile Bay Processing Partners investments. The impairment was recorded based on an expected loss from the anticipated sale of our interest in these investments.

Merchant Energy

Our Merchant Energy segment consists of two primary divisions: global power and other. Historically, our Merchant Energy segment also included our petroleum division. In June 2003, El Paso announced that its Board of Directors had approved the sale of substantially all of our petroleum operations. As a result, the petroleum operations were reclassified as discontinued operations for all the historical periods presented. For a further discussion of our petroleum operations, see Item 1, Note 6. Below are Merchant Energy's operating results and an analysis of those results for the periods ended June 30:

Merchant Energy Segment Results	Division		Total Merchant Energy Segment
	Global Power	Other	
	(In millions)		
Second Quarter 2003			
Gross margin	$ 56	$(11)	$ 45
Operating expenses	(25)	—	(25)
Operating income (loss)	31	(11)	20
Other income (expense)	13	(2)	11
EBIT	$ 44	$(13)	$ 31
Second Quarter 2002			
Gross margin	$ 116	$ —	$ 116
Operating expenses	(50)	4	(46)
Operating income	66	4	70
Other income	17	2	19
EBIT	$ 83	$ 6	$ 89
Six Months Ended 2003			
Gross margin	$ 100	$(14)	$ 86
Operating expenses	(57)	—	(57)
Operating income (loss)	43	(14)	29
Other income (expense)	32	(2)	30
EBIT	$ 75	$(16)	$ 59
Six Months Ended 2002			
Gross margin	$ 575	$ —	$ 575
Operating expenses	(104)	—	(104)
Operating income	471	—	471
Other income (expense)	(107)	6	(101)
EBIT	$ 364	$ 6	$ 370

Global Power

Our global power division includes the ownership and operation of domestic and international power generating facilities. Our 2002 Form 10-K includes a description of the various power activities included in global power. Due to a decline in El Paso's credit rating in late 2002 and early 2003, we no longer pursue power restructuring activities.

In 2002, we restructured several of our power plants which resulted in significant gains in 2002 and reduced operating revenues and expenses for those plants in 2003 because the plants were converted to merchant plants, operating only when economically feasible. Upon restructuring, we began recognizing changes in the fair value of the restructured derivative contracts in our earnings rather than when the power under the contracts was delivered. Going forward, the changes in fair value of these restructured derivative contracts, which are significantly impacted by changes in interest rates, may cause volatility in our future operating results.

As we execute sales of our domestic power plants, results of operations will increase or decrease from our current results based on the earnings and timing of the sale of the respective plant or investment. In addition to the earnings impact of the plant, a commitment to sell power plants in the future may trigger an event that could result in impairment charges in future periods.

Results of our global power division were as follows for the periods ended June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
Global Power Division Results	**2003**	**2002**	**2003**	**2002**
	(In millions)			
Gross margin	$ 56	$116	$100	$ 575
Operating expenses	(25)	(50)	(57)	(104)
Operating income	31	66	43	471
Other income (expense)	13	17	32	(107)
EBIT	$ 44	$ 83	$ 75	$ 364

Second Quarter 2003 Compared to Second Quarter 2002

Gross margin consists of revenues from our power plants and the net results from our power restructuring activities. The cost of fuel in the power generation process is included in operating expenses. For the quarter ended June 30, 2003, our gross margin was $60 million lower than the same period in 2002. The decrease was primarily due to a $90 million gain recorded in 2002 on the termination of a power purchase agreement at our Nejapa power facility and lower power generation revenues of $27 million due to the partial shutdown of our Eagle Point Cogeneration facility during the first six months of 2003 for maintenance needed to convert the power plant to a merchant power plant. Partially offsetting these decreases was an increase of $26 million due to the increases in the fair values of our power restructuring contracts in 2003.

Operating expenses for the quarter ended June 30, 2003, were $25 million lower than the same period in 2002. The decrease was primarily due to lower fuel costs with our power plants of $14 million. Also, contributing to the decrease was a $2 million decrease in operating costs related to the shutdown of our Eagle Point Cogeneration facility for maintenance in 2003.

Six Months Ended 2003 Compared to Six Months Ended 2002

For the six months ended June 30, 2003, our gross margin was $475 million lower than the same period in 2002. The decrease was primarily due to power contract restructurings for our Eagle Point Cogeneration and Nejapa power plants that we completed in 2002, which contributed $498 million to our gross margin in 2002, including an $80 million loss on a power supply agreement that we entered into with E1 Paso in the first quarter of 2002 associated with the Eagle Point Cogeneration restructuring transaction. The effects of this power supply agreement were eliminated from Merchant Energy's consolidated results. Contributing to the decrease in gross margin was a decrease of $63 million in 2003 power generation revenues primarily due to the partial shutdown of our Eagle Point Cogeneration facility during the first six months of 2003 for maintenance needed to convert the power plant to a merchant power plant. Partially offsetting these decreases were increases in the fair values of our power restructuring contracts of $44 million during 2003.

Operating expenses for the six months ended June 30, 2003, were $47 million lower than the same period in 2002. The decrease was primarily due to lower fuel costs with our power plants of $23 million. Also contributing to the decrease is a $8 million decrease in operating costs related to the shutdown of our Eagle Point Cogeneration facility for maintenance in 2003 and a $6 million decrease in depreciation expense in 2003 primarily due to lower depreciation on our Eagle Point Cogeneration facility.

Other income for the six months ended June 30, 2003, was $139 million higher than the same period in 2002. This increase is primarily due to a $90 million contract termination fee we paid in 2002 to our petroleum division associated with the termination of a steam contract between our Eagle Point Cogeneration facility and the Eagle Point refinery (which is included in our petroleum division reflected in discontinued operations). Also contributing to this increase was $52 million of minority interest expense recorded primarily on our power plant restructurings during 2002.

Other

Results of our other division were as follows for the periods ended June 30:

Other Division Results	Quarter Ended June 30, 2003	Quarter Ended June 30, 2002	Six Months Ended June 30, 2003	Six Months Ended June 30, 2002
	(In millions)			
Gross margin	$(11)	$—	$(14)	$—
Operating expense	—	4	—	—
Operating income (loss)	(11)	4	(14)	—
Other income (expense)	(2)	2	(2)	6
EBIT	$(13)	$ 6	$(16)	$ 6

For the quarter and six months ended June 30, 2003, gross margin was $11 million and $14 million lower than the same period in 2002 primarily due to the change in fair value of a gas supply derivative with El Paso Tennessee Pipeline's trading division that was consolidated in late 2002.

Interest and Debt Expense

Interest and debt expense for the quarter and six months ended June 30, 2003, was $4 million and $8 million lower than the same period in 2002. Below is the analysis of our interest expense for the periods ended June 30:

	Quarter Ended June 30, 2003	Quarter Ended June 30, 2002	Six Months Ended June 30, 2003	Six Months Ended June 30, 2002
	(In millions)			
Long-term debt, including current maturities	$102	$ 98	$201	$196
Other interest	1	11	4	20
Capitalized interest	(3)	(5)	(6)	(9)
Total interest expense	$100	$104	$199	$207

Second Quarter 2003 Compared to Second Quarter 2002

Interest expense on long-term debt for the quarter ended June 30, 2003, was $4 million higher than the same period in 2002 primarily due to a $19 million increase in interest from Utility Contract Funding borrowed in July 2002 and Mohawk River Funding IV debt borrowed in June 2002. These debts were borrowed for ongoing capital projects, investment programs and operating requirements. Also contributing to the increase was $5 million of additional interest related to ANR's March 2003 issuance of $300 million senior notes. These increases were partially offset by a $19 million decrease in interest due to the retirement of approximately $1 billion of long-term debt in 2002 and 2003 with an average interest rate of 7.42%.

Other interest for the quarter ended June 30, 2003, was $10 million lower than the same period in 2002. The decrease was primarily due to a $9 million decrease in interest resulting from retirement of our other financing obligations.

Capitalized interest for the quarter ended June 30, 2003, was $2 million lower than the same period in 2002 primarily due to lower interest rates in the second quarter 2003 than the same period in 2002.

Six Months Ended 2003 Compared to Six Months Ended 2002

Interest expense on long-term debt for the six months ended June 30, 2003, was $5 million higher than the same period in 2002 primarily due to a $38 million increase in interest from Utility Contract Funding borrowed in July 2002 and Mohawk River Funding IV debt borrowed in June 2002. These debts were borrowed for ongoing capital projects, investment programs and operating requirements. Also contributing to the increase was $7 million of additional interest related to ANR's March 2003 issuance of $300 million senior notes. These increases were partially offset by a $40 million decrease in interest due to the retirement of approximately $1.4 billion of long-term debt in 2002 and 2003 with an average interest rate of 6.91%.

Other interest for the six months ended June 30, 2003, was $16 million lower than the same period in 2002. The decrease was primarily due to a $13 million decrease in interest resulting from retirement of our other financing obligations, a $2 million decrease in factoring of receivables and a $2 million decrease in interest due to termination of a marketing sales contract during 2002.

Capitalized interest for the six months ended June 30, 2003, was $3 million lower than the same period in 2002 primarily due to lower interest rates in 2003 than 2002.

Affiliated Interest Expense, Net

Affiliated interest expense, net for quarter and six months ended June 30, 2003, was $7 million and $14 million, or $5 million and $8 million higher than the same period in 2002. The increase was primarily due to higher average advances payable to El Paso under our cash management program in 2003, partially offset by lower average short-term interest rates. The average advances payable balance for the second quarter increased from $666 million in 2002 to $2,265 million in 2003 and the average advances payable balance for the six months increased from $622 million in 2002 to $2,140 million in 2003. The average short-term interest rates for the second quarter decreased from 1.9% in 2002 to 1.3% in 2003 and the average short-term interest rate for the six months decreased from 1.9% in 2002 to 1.3% in 2003.

Distributions on Preferred Interests of Consolidated Subsidiaries

Distributions on preferred interests of consolidated subsidiaries for the quarter and six months ended June 30, 2003, were $4 million and $7 million lower than the same periods in 2002 primarily due to the redemptions or elimination of over $350 million of the preferred interests related to El Paso Oil & Gas Associates, Coastal Limited Ventures and El Paso Oil & Gas Resources in July 2002.

Income Taxes

Income taxes from continuing operations and our effective tax rates for the periods ended June 30 were as follows:

	Quarter Ended June 20,		Six Months Ended June 30,	
	2003	2002	2003	2002
	(In millions, except rates)			
Income taxes	$77	$ 5	$89	$167
Effective tax rate	151%	26%	35%	32%

Our effective tax rates were different than the statutory tax rate of 35 percent in 2003 primarily due to the following:

- state income taxes, net of federal income tax benefit; and
- foreign income taxed at different rates.

Additionally, income taxes from continuing operations for the quarter ended June 30, 2003, include an adjustment to our estimated annual income tax rate as a result of the reclassification of our petroleum business to discontinued operations. This rate estimate adjustment caused us to record additional taxes for the six month period that, when added to taxes on second quarter income, resulted in the unusually high effective tax rate for the second quarter of 151%.

Discontinued Operations

During the six months ended June 30, 2003, our after-tax loss from discontinued operations was $1,138 million. During this period, we recorded pre-tax charges of $1,366 million related to impairments of long-lived assets and investments triggered by our decision to sell substantially all of our petroleum businesses, approximately $929 million of which related to the second quarter impairment of our Aruba refinery and approximately $252 million of which related to the first quarter impairment of our Eagle Point refinery.

We also incurred losses on our refinery operations during the second quarter of 2003 of $74 million, which primarily related to lower pricing in the second quarter and lower crude throughput at our Aruba facility. Year to date operating results for our refineries were slightly positive at $5 million.

The income tax benefit related to discontinued operations for the six months ended June 30, 2003, was $226 million resulting in an effective tax rate for discontinued operations of 17 percent. This effective rate was different than the statutory rate of 35 percent primarily due to state income taxes and foreign income taxes at different rates.

In the second quarter of 2003, we entered into a product offtake agreement for the sale of a number of the products produced at our Aruba refinery. As a result of this contract, the buyer became the single largest customer of our Aruba refinery, purchasing approximately 75 percent of the products produced at that plant. The agreement is for one year with two one-year extensions at the buyer's option. We have the right to terminate the agreement when the refinery is sold.

Commitments and Contingencies

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

New Accounting Pronouncements Issued But Not Yet Adopted

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

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

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

Item 3. Quantitative and Qualitative Disclosures About Market Risk

This information updates, and you should read it in conjunction with, information disclosed in Part II, Item 7A in our Annual Report on Form 10-K for the year ended December 31, 2002, in addition to the information presented in Items 1 and 2 of this Quarterly Report on Form 10-Q.

There are no material changes in our quantitative and qualitative disclosures about market risks from those reported in our 2002 Annual Report on Form 10-K.

Item 4. Controls and Procedures

Evaluation of Controls and Procedures. Under the supervision and with the participation of management, including our principal executive officer and principal financial officer, we have evaluated the effectiveness of the design and operation of our disclosure controls and procedures (Disclosure Controls) and internal controls over financial reporting (Internal Controls) as of the end of the period covered by this Quarterly Report pursuant to Rules 13a-15 and 15d-15 under the Securities Exchange Act of 1934 (Exchange Act).

Definition of Disclosure Controls and Internal Controls. Disclosure Controls are our controls and other procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified under the Exchange Act. Disclosure Controls include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in the reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure. Internal Controls are procedures which are designed with the objective of providing reasonable assurance that (1) our transactions are property authorized; (2) our assets are safeguarded against unauthorized or improper use; and (3) our transactions are properly recorded and reported, all to permit the preparation of our financial statements in conformity with generally accepted accounting principles.

Limitations on the Effectiveness of Controls. El Paso CGP Company's management, including the principal executive officer and principal financial officer, does not expect that our Disclosure Controls and Internal Controls will prevent all errors and all fraud. The design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple errors or mistakes. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events. Therefore, a control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Our Disclosure Controls and Internal Controls are designed to provide such reasonable assurances of achieving our desired control objectives, and our principal executive officer and principal financial officer have concluded that our Disclosure Controls and Internal Controls are effective in achieving that level of reasonable assurance.

No Significant Changes in Internal Controls. We have sought to determine whether there were any "significant deficiencies" or "material weaknesses" in El Paso CGP Company's Internal Controls, or whether the company had identified any acts of fraud involving personnel who have a significant role in El Paso CGP Company's Internal Controls. This information was important both for the controls evaluation generally and because the principal executive officer and principal financial officer are required to disclose that information to our Board's Audit Committee and our independent auditors and to report on related matters in this section of the Quarterly Report. The principal executive officer and principal financial officer note that there has not been any change in Internal Controls during the period covered by this Quarterly Report that has materially affected, or is reasonably likely to materially affect, Internal Controls.

Effectiveness of Disclosure Controls. Based on the controls evaluation, our principal executive officer and principal financial officer have concluded that the Disclosure Controls are effective to ensure that material information relating to El Paso CGP Company and its consolidated subsidiaries is made known to management, including the principal executive officer and principal financial officer, on a timely basis.

Officer Certification. The certifications from the principal executive officer and principal financial officer required under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 have been included as Exhibits to this Quarterly Report.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings.

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

Item 2. Changes in Securities and Use of Proceeds.

None.

Item 3. Defaults Upon Senior Securities.

None.

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

None.

Item 5. Other Information.

None.

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

a. Exhibits.

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

Exhibit Number	Description
*31.A	Certification of Chief Executive Officer pursuant to § 302 of the Sarbanes-Oxley Act of 2002.
*31.B	Certification of Chief Financial Officer pursuant to § 302 of the Sarbanes-Oxley Act of 2002.
*32.A	Certification of Chief Executive Officer pursuant to 18 U.S.C. § 1350 as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002.
*32.B	Certification of Chief Financial Officer pursuant to 18 U.S.C. § 1350 as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002.

Undertaking

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

b. Reports on Form 8-K

None.

SIGNATURES

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

EL PASO CGP COMPANY

Date: August 14, 2003

/s/ D. DWIGHT SCOTT

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

Date: August 14, 2003

/s/ JEFFREY I. BEASON

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