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, 2005

OR

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

For the transition period from to

Commission File Number 1-14365

El Paso Corporation

(Exact Name of Registrant as Specified in its Charter)

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

Telephone Number: **(713) 420-2600**
Internet Website: www.elpaso.com

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange 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 $3 per share. Shares outstanding on August 2, 2005: 645,719,039

EL PASO CORPORATION

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

/d	= per day	Mcfe	= thousand cubic feet of natural gas equivalents
Bbl	= barrels	MMBtu	= million British thermal units
BBtu	= billion British thermal units	MMcf	= million cubic feet
Bcf	= billion cubic feet	MMcfe	= million cubic feet of natural gas equivalents
Bcfe	= billion cubic feet of natural gas equivalents	MW	= megawatt
MBbls	= thousand barrels	NGL	= natural gas liquids
Mcf	= thousand cubic feet	TBtu	= trillion British thermal units

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", we are describing El Paso Corporation and/or our subsidiaries.

PART I — FINANCIAL INFORMATION

Item 1. Financial Statements

EL PASO CORPORATION

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

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
Operating revenues	$1,224	$1,524	$2,366	$3,081
Operating expenses				
Cost of products and services	60	435	159	825
Operation and maintenance	438	373	880	774
Depreciation, depletion and amortization	294	263	574	538
Loss on long-lived assets	360	17	381	255
Taxes, other than income taxes	65	66	136	130
	1,217	1,154	2,130	2,522
Operating income (loss)	7	370	236	559
Earnings (loss) from unconsolidated affiliates	(19)	98	171	185
Other income, net	71	30	104	74
Interest and debt expense	(340)	(410)	(690)	(833)
Distributions on preferred interests of consolidated subsidiaries	(3)	(6)	(9)	(12)
Income (loss) before income taxes	(284)	82	(188)	(27)
Income taxes	(51)	48	(57)	58
Income (loss) from continuing operations	(233)	34	(131)	(85)
Discontinued operations, net of income taxes	(5)	(29)	(1)	(106)
Net income (loss)	(238)	5	(132)	(191)
Preferred stock dividends	(8)	—	(8)	—
Net income (loss) available to common stockholders	$ (246)	$ 5	$ (140)	$ (191)
Basic and diluted income (loss) per common share				
Income (loss) from continuing operations	$(0.37)	$ 0.05	$(0.22)	$(0.13)
Discontinued operations, net of income taxes	(0.01)	(0.04)	—	(0.17)
Net income (loss) per common share	$(0.38)	$ 0.01	$(0.22)	$(0.30)
Basic and diluted average common shares outstanding	641	639	640	639
Dividends declared per common share	$ 0.04	$ 0.04	$ 0.08	$ 0.08

See accompanying notes.

EL PASO CORPORATION

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

	June 30, 2005	December 31, 2004
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,540	$ 2,117
Accounts and notes receivable		
Customers, net of allowance of $77 in 2005 and $199 in 2004	975	1,388
Affiliates	90	133
Other	151	188
Assets from price risk management activities	576	601
Margin and other deposits held by others	328	79
Deferred income taxes	607	418
Other	539	708
Total current assets	4,806	5,632
Property, plant and equipment, at cost		
Pipelines	19,609	19,418
Natural gas and oil properties, at full cost	15,693	14,968
Power facilities	957	1,550
Gathering and processing systems	64	171
Other	629	882
	36,952	36,989
Less accumulated depreciation, depletion and amortization	18,265	18,177
Total property, plant and equipment, net	18,687	18,812
Other assets		
Investments in unconsolidated affiliates	2,275	2,614
Assets from price risk management activities	1,203	1,584
Goodwill and other intangible assets, net	422	428
Other	2,283	2,313
	6,183	6,939
Total assets	$29,676	$31,383

See accompanying notes.

EL PASO CORPORATION

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

	June 30, 2005	December 31, 2004
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 792	$ 1,052
Affiliates	8	21
Other	399	483
Short-term financing obligations, including current maturities	1,099	955
Liabilities from price risk management activities	920	852
Margin and other deposits	342	131
Western Energy Settlement	—	44
Accrued interest	281	333
Other	818	701
Total current liabilities	4,659	4,572
Long-term financing obligations, less current maturities	16,379	18,241
Other		
Liabilities from price risk management activities	1,390	1,026
Deferred income taxes	1,528	1,312
Western Energy Settlement	—	351
Other	1,861	2,076
	4,779	4,765
Commitments and contingencies		
Securities of subsidiaries	59	367
Stockholders' equity		
4.99% Convertible perpetual preferred stock, par value $0.01 per share; authorized 50,000,000 shares; issued 750,000 shares in 2005; stated at liquidation value	750	—
Common stock, par value $3 per share; authorized 1,500,000,000 shares; issued 653,065,090 shares in 2005 and 651,064,508 shares in 2004	1,959	1,953
Additional paid-in capital	4,431	4,538
Accumulated deficit	(2,941)	(2,809)
Accumulated other comprehensive income (loss)	(183)	1
Treasury stock (at cost); 7,361,325 shares in 2005 and 7,767,088 shares in 2004	(189)	(225)
Unamortized compensation	(27)	(20)
Total stockholders' equity	3,800	3,438
Total liabilities and stockholders' equity	$29,676	$31,383

See accompanying notes.

EL PASO CORPORATION

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

	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
Cash flows from operating activities		
Net loss	$ (132)	$ (191)
Less loss from discontinued operations, net of income taxes	(1)	(106)
Net loss from continuing operations	(131)	(85)
Adjustments to reconcile net loss to net cash from operating activities		
Depreciation, depletion and amortization	574	538
Loss on long-lived assets	381	255
Earnings from unconsolidated affiliates, adjusted for cash distributions	(24)	(27)
Deferred income taxes	4	37
Other non-cash items	35	53
Other asset and liability changes	(812)	(636)
Cash provided by continuing operations	27	135
Cash provided by (used in) discontinued operations	(17)	161
Net cash provided by operating activities	10	296
Cash flows from investing activities		
Additions to property, plant and equipment	(806)	(782)
Purchases of interests in equity investments	(15)	(21)
Net proceeds from the sale of assets and investments	834	165
Proceeds from settlement of a foreign currency derivative	131	—
Cash paid for acquisitions, net of cash acquired	(178)	2
Net change in restricted cash	62	447
Net change in notes receivable from unconsolidated affiliates	5	98
Other	47	—
Cash provided by (used in) continuing operations	80	(91)
Cash provided by discontinued operations	70	1,113
Net cash provided by investing activities	150	1,022
Cash flows from financing activities		
Payments to retire long-term debt and other financing obligations	(1,563)	(1,024)
Net proceeds from the issuance of long-term debt and other financing obligations	458	50
Net proceeds from the issuance of preferred stock	723	—
Redemption of preferred stock of subsidiary	(300)	—
Dividends paid	(51)	(49)
Contributions from discontinued operations	53	909
Issuances of common stock, net	—	73
Other	(4)	(21)
Cash used in continuing operations	(684)	(62)
Cash used in discontinued operations	(53)	(1,274)
Net cash used in financing activities	(737)	(1,336)
Change in cash and cash equivalents	(577)	(18)
Cash and cash equivalents		
Beginning of period	2,117	1,429
End of period	$ 1,540	$ 1,411

See accompanying notes.

EL PASO CORPORATION

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

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
Net income (loss)	$(238)	$ 5	$(132)	$(191)
Foreign currency translation adjustments (net of income taxes of $6 and $7 in 2005 and $14 and $51 in 2004)	(4)	(24)	7	(20)
Unrealized net gains (losses) from cash flow hedging activity				
Unrealized mark-to-market gains (losses) arising during period (net of income taxes of $13 and $89 in 2005 and $2 and $12 in 2004)	17	(4)	(172)	(23)
Reclassification adjustments for changes in initial value to the settlement date (net of income taxes of $1 and $12 in 2005 and $7 and $15 in 2004)	2	24	(19)	39
Other comprehensive income (loss)	15	(4)	(184)	(4)
Comprehensive income (loss)	$(223)	$ 1	$(316)	$(195)

See accompanying notes.

EL PASO CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Basis of Presentation and Significant Accounting Policies

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 this Quarterly Report on Form 10-Q along with our 2004 Annual Report on Form 10-K, as amended, which includes a summary of our significant accounting policies and other disclosures. The financial statements as of June 30, 2005, and for the quarters and six months ended June 30, 2005 and 2004, are unaudited. We derived the balance sheet as of December 31, 2004, from the audited balance sheet filed in our 2004 Annual Report on Form 10-K, as amended. 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 be indicative of the results of operations for the entire year. During the second quarter of 2005, our Board of Directors approved the sale of our south Louisiana gathering and processing assets, which were part of our Field Services segment. These assets and the results of their operations for the quarter and six months ended June 30, 2005, have been reclassified as discontinued operations. Prior period amounts have not been adjusted as these operations were not material to prior period results or historical trends. Additionally, our financial statements for prior periods include reclassifications to conform to the current period presentation. These reclassifications had no effect on our previously reported net income (loss) or stockholders' equity.

Significant Accounting Policies

Our significant accounting policies are discussed in our 2004 Annual Report on Form 10-K, as amended. The information below provides updating information, disclosure where these policies have changed or required interim disclosures with respect to those policies.

Variable Interest Entities

In 2003, the Financial Accounting Standards Board (FASB) issued Financial Interpretation (FIN) No. 46, *Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51*, which we adopted on January 1, 2004. This interpretation defined a variable interest entity as a legal entity whose equity owners do not have sufficient equity at risk 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 or income, including fees paid by the entity.

In conjunction with our application of FIN No. 46, we attempted to obtain financial information on several potential variable interest entities but were unable to obtain that information. The most significant of these entities is the Cordova power project which is the counterparty to our largest tolling arrangement. Under this tolling arrangement, we supply on average a total of 54,000 MMBtu of natural gas per day to the entity's two 274 gross MW power facilities and are obligated to market the power generated by those facilities through 2019. In addition, we pay that entity a capacity charge that ranges from $27 million to $32 million per year related to its power plants. The following is a summary of the financial statement impacts of our transactions with this entity for the six months ended June 30, 2005 and 2004 and as of June 30, 2005 and December 31, 2004:

	2005	2004
	(In millions)	
Operating revenues	$(111)	$(3)
Current liabilities from price risk management activities	21	20
Non-current liabilities from price risk management activities	127	29

As of December 31, 2004, our financial statements included two consolidated entities that own a 238 MW power facility and a 158 MW power facility in Manaus, Brazil. In January 2005, these entities entered into agreements with Manaus Energia, under which Manaus Energia will supply substantially all of the fuel consumed and will purchase all of the power generated by the projects through January 2008, at which time Manaus Energia will assume ownership of the plants. We deconsolidated these two entities in January 2005 because Manaus Energia will absorb a majority of the potential losses of the entities under the new agreements and will assume ownership of the plants at the end of the agreements. The impact of this deconsolidation was an increase in investments in unconsolidated affiliates of $103 million, a decrease in property, plant and equipment of $74 million, a decrease in other assets of $32 million and a decrease in other liabilities of $3 million.

Stock-Based Compensation

We account for our stock-based compensation plans using the intrinsic value method under the provisions of Accounting Principles Board Opinion (APB) No. 25, *Accounting for Stock Issued to Employees,* and its related interpretations. Had we accounted for our stock option grants using Statement of Financial Accounting Standards (SFAS) No. 123, *Accounting for Stock-Based Compensation,* rather than APB No. 25, the loss and per share impacts of stock-based compensation on our financial statements would have been different. The following table shows the impact on net income (loss) and income (loss) per share had we applied SFAS No. 123:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
	(In millions)			
Net income (loss) available to common stockholders as reported	$ (246)	$ 5	$ (140)	$ (191)
Add: Stock-based compensation expense in net income (loss), net of taxes	3	7	5	11
Deduct: Stock-based compensation expense determined under fair value-based method for all awards, net of taxes	5	11	10	21
Net loss available to common stockholders, pro forma	$ (248)	$ 1	$ (145)	$ (201)
Income (loss) per share:				
Basic and diluted, as reported	$(0.38)	$0.01	$(0.22)	$(0.30)
Basic and diluted, pro forma	$(0.39)	$ —	$(0.23)	$(0.31)

New Accounting Pronouncements Issued But Not Yet Adopted

As of June 30, 2005, there were several accounting standards and interpretations that had not yet been adopted by us. Below is a discussion of significant standards that may impact us.

Accounting for Stock-Based Compensation. In December 2004, the FASB issued SFAS No. 123R, *Share-Based Payment: an amendment of SFAS No. 123 and 95.* This standard requires that companies measure and record the fair value of their stock based compensation awards at fair value on the date they are granted to employees. This fair value is determined using a variety of assumptions, including those related to volatility rates, forfeiture rates and the option pricing model used (e.g. binomial or Black Scholes). These assumptions could differ from those we have utilized in determining our proforma compensation expense (indicated above). This standard will also impact the manner in which we recognize the income tax impacts of our stock compensation programs in our financial statements. This standard is required to be adopted beginning January 1, 2006. Upon adoption, we will apply the standard prospectively for new stock-based compensation arrangements and the unvested portion of existing arrangements. We are currently evaluating the impact of this adoption on our consolidated financial statements.

Accounting for Deferred Taxes on Foreign Earnings. In December 2004, the FASB issued FASB Staff Position (FSP) No. 109-2, *Accounting and Disclosure Guidance for the Foreign Earnings Repatriation Provision within the American Jobs Creation Act of 2004.* FSP No. 109-2 clarified the existing accounting literature that requires companies to record deferred taxes on foreign earnings, unless they intend to indefinitely reinvest those earnings outside the U.S. This pronouncement will temporarily allow companies that are evaluating whether to repatriate foreign earnings under the American Jobs Creation Act of 2004 to delay recognizing any related taxes until that decision is made. This pronouncement also requires companies that are considering repatriating earnings to disclose the status of their evaluation and the potential amounts being considered for repatriation. The U.S. Treasury Department has indicated that additional guidance for applying the repatriation provisions of the American Jobs Creation Act of 2004 will be issued. We have not yet determined the potential range of our foreign earnings that could be impacted by this legislation and FSP No. 109-2, and we continue to evaluate whether we will repatriate any foreign earnings and the impact, if any, that this pronouncement will have on our financial statements.

Accounting for Asset Retirement Obligations. In March 2005, the FASB issued FIN No. 47, *Accounting for Conditional Asset Retirement Obligations.* FIN No. 47 requires companies to record a liability for those asset retirement obligations in which the timing and/or amount of settlement of the obligation are uncertain. These conditional obligations were not addressed by SFAS No. 143, *Accounting for Asset Retirement Obligations*, which we adopted on January 1, 2003. FIN No. 47 will require us to accrue a liability when a range of scenarios indicates that the potential timing and/or settlement amounts of our conditional asset retirement obligations can be determined. We will adopt the provisions of this standard in the fourth quarter of 2005 and have not yet determined the impact, if any, that this pronouncement will have on our financial statements.

Accounting for Pipeline Integrity Costs. In June 2005, the Federal Energy Regulatory Commission (FERC), issued an accounting release that will impact certain costs our interstate pipelines incur related to their pipeline integrity programs. This release will require us to expense certain pipeline integrity costs incurred after January 1, 2006, instead of capitalizing them as part of our property, plant and equipment. Although we continue to evaluate the impact that this accounting release will have on our consolidated financial statements, we currently estimate that we would be required to expense an additional amount of pipeline integrity costs under the release in the range of approximately $23 million to $39 million annually.

2. Acquisitions

In July 2005, we announced that our subsidiary, El Paso Production Holding Company (EPPH), will acquire Medicine Bow Energy Corporation for $814 million in cash. This transaction is expected to close during the third quarter of 2005.

3. Divestitures

Sales of Assets and Investments

During the six months ended June 30, 2005 and 2004, we completed the sale of a number of assets and investments in each of our business segments. The following table summarizes the proceeds from these sales:

	2005	2004
	(In millions)	
Regulated		
Pipelines	$ 35	$ 50
Non-regulated		
Power	176	99
Field Services	501	—
Other		
Corporate	121	16
Total continuing	833[1]	165
Discontinued	85	1,261
Total	$918	$1,426

(1) Proceeds exclude returns of capital from unconsolidated affiliates and cash transferred with the assets sold and include costs incurred for disposal. These increased our sales proceeds by $1 million for the six months ended June 30, 2005.

The following table summarizes the significant assets sold during the six months ended June 30:

	2005	2004
Pipelines	• Facilities located in the southeastern U.S.	• Australia pipeline • Aircraft
Power	• Cedar Brakes I and II • Interest in a power plant in India • Interest in a power plant in England • 4 domestic power facilities • Power turbine	• Mohawk River Funding IV • Utility Contract Funding (UCF) • Bastrop Company equity investment
Field Services	• 9.9% interest in general partner of Enterprise Products Partners, L.P. • 13.5 million common units in Enterprise • Interest in Indian Springs natural gas gathering system and processing facility	• None
Corporate	• Lakeside Technology Center	• Aircraft
Discontinued	• Interest in Paraxylene facility • MTBE processing facility • International natural gas and oil production properties	• Natural gas and oil production properties in Canada • Aruba and Eagle Point refineries and other petroleum assets

In the third quarter of 2005, we also completed the sale of our 50 percent interest in the Korean Independent Energy Corporation power facility. We will record the receipt of $284 million in proceeds and a $109 million gain in the third quarter of 2005 related to this sale in our Power segment. Additionally, in the second and third quarters of 2005, we announced the sales of substantially all of our other Asia power assets. We expect to receive total proceeds of approximately $180 million for these assets.

Under SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, we classify assets to be disposed of as held for sale or, if appropriate, discontinued operations when they have received appropriate approvals by our management or Board of Directors and when they meet other criteria. As of June 30, 2005, we had assets held for sale of $5 million related to two Asian power plants and a domestic power asset, which was fully impaired in previous years. We expect to sell these assets within the next twelve months. As of December 31, 2004, we had assets held for sale of $75 million related to our Indian Springs natural gas gathering system and processing facility which was sold in the first quarter of 2005 and certain domestic power assets.

Discontinued Operations

South Louisiana Gathering and Processing Operations. During the second quarter of 2005, our Board of Directors approved the sale of our south Louisiana gathering and processing assets, which were part of our Field Services segment. This sale is expected to be completed by the end of 2005.

International Natural Gas and Oil Production Operations. During 2004, our Canadian and certain other international natural gas and oil production operations were approved for sale. As of December 31, 2004, we had completed the sale of all of our Canadian operations and substantially all of our operations in Indonesia for total proceeds of approximately $389 million. We completed the sale of substantially all of our remaining properties in 2005 for total proceeds of approximately $6 million.

Petroleum Markets. During 2003, our Board of Directors approved the sales of our petroleum markets businesses and operations. These businesses and operations consisted of our Eagle Point and Aruba refineries, our asphalt business, our Florida terminal, tug and barge business, our lease crude operations, our Unilube blending operations, our domestic and international terminalling facilities and our petrochemical and chemical plants. In 2004, we completed the sales of our Aruba and Eagle Point refineries for $880 million.

The petroleum markets, other international natural gas and oil production operations, and south Louisiana gathering and processing operations discussed above are classified as discontinued operations in our financial statements. As of June 30, 2005 and December 31, 2004, the total assets of our discontinued operations were $193 million and $106 million, and our total liabilities were $121 million and $12 million. These amounts are classified in other current assets and liabilities. The assets and liabilities of our south Louisiana gathering and processing operations as of December 31, 2004, and the results of its operations for periods prior to January 1, 2005, were not reclassified to discontinued operations, as these operations were not material to prior period results or historical trends. The summarized operating results of our discontinued operations were as follows:

	Petroleum Markets	International Natural Gas and Oil Production Operations	South Louisiana Gathering and Processing Operations	Total
	(In millions)			
Operating Results Data				
Quarter Ended June 30, 2005				
Revenues	$ 30	$ —	$ 90	$ 120
Costs and expenses	(33)	(1)	(79)	(113)
Loss on long-lived assets	—	(4)	—	(4)
Other expense	(4)	—	—	(4)
Income (loss) before income taxes	(7)	(5)	11	(1)
Income taxes	1	(2)	5	4
Income (loss) from discontinued operations, net of income taxes	$ (8)	$ (3)	$ 6	$ (5)
Quarter Ended June 30, 2004				
Revenues	$ 54	$ 1	$ —	$ 55
Costs and expenses	(77)	(3)	—	(80)
Gain on long-lived assets	4	—	—	4
Other income	2	—	—	2
Loss before income taxes	(17)	(2)	—	(19)
Income taxes	(3)	13	—	10
Loss from discontinued operations, net of income taxes	$ (14)	$(15)	$ —	$ (29)
Six Months Ended June 30, 2005				
Revenues	$ 74	$ 2	$ 177	$ 253
Costs and expenses	(86)	(2)	(157)	(245)
Gain (loss) on long-lived assets	3	(5)	—	(2)
Other income	11	—	—	11
Income (loss) before income taxes	2	(5)	20	17
Income taxes	13	(3)	8	18
Income (loss) from discontinued operations, net of income taxes	$ (11)	$ (2)	$ 12	$ (1)

	Petroleum Markets	International Natural Gas and Oil Production Operations	South Louisiana Gathering and Processing Operations	Total
		(In millions)		
Six Months Ended June 30, 2004				
Revenues	$ 693	$ 28	$ —	$ 721
Costs and expenses	(730)	(47)	—	(777)
Loss on long-lived assets	(38)	(16)	—	(54)
Interest and debt expense	(3)	1	—	(2)
Other expense	(8)	—	—	(8)
Loss before income taxes	(86)	(34)	—	(120)
Income taxes	(9)	(5)	—	(14)
Loss from discontinued operations, net of income taxes	$ (77)	$(29)	$ —	$(106)

4. Restructuring Costs

During 2004 and 2005, we incurred organizational restructuring costs included in our operation and maintenance expenses as part of our ongoing liquidity enhancement and cost reduction efforts. The discussion below provides additional details of these costs.

Office relocation and consolidation. As of December 31, 2004, we had a liability related to our remaining lease obligations associated with the consolidation of our Houston based operations. This liability was discounted, net of estimated sub-lease rentals. During the quarter and six months ended June 30, 2005, we recorded additional charges of $17 million related to vacating this remaining leased space. In June 2005, we signed a termination agreement releasing us from this lease obligation, which resulted in an additional charge of $10 million. As of June 30, 2005, our total liability was $114 million.

Employee severance, retention, and transition costs. During the six months ended June 30, 2004, we incurred $33 million of employee severance costs, which included severance payments and costs for pension benefits settled under existing benefit plans. During this period, we eliminated approximately 350 full-time positions from our continuing business and approximately 1,100 positions related to businesses we discontinued. During the six months ended June 30, 2005, severance costs were not significant. Substantially all of our employee severance costs have been paid as of June 30, 2005.

5. Loss on Long-Lived Assets

Our loss on long-lived assets consists of realized gains and losses on sales of long-lived assets and impairments of long-lived assets. During each of the periods ended June 30, our loss on long-lived assets was as follows:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
	(In millions)			
Net realized gain	$ (6)	$(6)	$(13)	$(14)
Asset impairments	366	23	394	269
Loss on long-lived assets	360	17	381	255
(Gain) loss on investments in unconsolidated affiliates[1]	87	18	(32)	42
Loss on long-lived assets and investments	$447	$35	$349	$297

[1] See Note 14 for a further description of these gains and losses.

Net Realized Gain

Our 2005 net realized gains are primarily related to a $9 million gain on the sale of facilities located in the southeastern United States in our Pipelines segment. Also, during the second quarter of 2005, our corporate operations recorded a $5 million gain on the sale of our Lakeside Technology Center, which was previously impaired in 2003. Our 2004 net realized gains are primarily related to a gain on aircraft sales associated with our corporate activities.

Asset Impairments

In 2005, our Power segment recorded approximately $388 million of asset impairments. During the quarter ended June 30, 2005, we recorded a $276 million impairment of our long-lived assets associated with the Macae power project in Brazil as a result of ongoing negotiations with Petrobras related to the plant. See Note 10 for a further discussion of these matters. Our Power segment also recorded impairments of $14 million during the first quarter of 2005 and $83 million during the second quarter of 2005 related to our Asian and Central American assets based on additional information received about the value we may receive upon the sale of these assets. Finally, in the first quarter of 2005, we recorded a $15 million impairment of our power turbines based on further information we received about their fair value.

Our 2004 asset impairments primarily occurred in our Power segment, including a $151 million impairment during the first quarter of 2004 related to our Manaus and Rio Negro power plants in Brazil based on the status of our negotiations to extend the power contracts at these plants, which was negatively impacted by changes in the Brazilian political environment. In addition, our Power segment recorded a $98 million impairment charge during the first quarter of 2004 related to the sale of our subsidiary, Utility Contract Funding, which owned a restructured power contract, and $10 million of impairments in the second quarter of 2004 on our domestic power plants to adjust the carrying value of these plants to their expected sales price. Finally, our Field Services segment recorded $7 million of impairments in the second quarter of 2004, primarily related to the abandonment of miscellaneous assets.

6. Income Taxes

Income taxes included in our income (loss) from continuing operations for the periods ended June 30 were as follows:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
	(In millions, except rates)			
Income taxes	$(51)	$48	$(57)	$ 58
Effective tax rate	18%	59%	30%	(215)%

We compute our quarterly taxes under the effective tax rate method based on applying an anticipated annual effective rate to our year-to-date income or loss, except for significant unusual or extraordinary transactions. Income taxes for significant unusual or extraordinary transactions are computed and recorded in the period that the specific transaction occurs. During 2005, our overall effective tax rate on continuing operations was different than the statutory rate of 35% due primarily to:

- Impairments of certain foreign investments for which there was only a partial corresponding income tax benefit, as well as foreign income taxed at different rates;
- Benefits recorded on book versus tax differences related to certain of our Asian and Indian power assets as further described below;
- A reduction of our liabilities for tax contingencies as a result of an IRS settlement on the 1995 to 1997 Coastal Corporation income tax returns of $33 million, expiration of a tax indemnity claim, and approval of a 1986 refund claim; and

- Other items including (i) state income taxes (including valuation allowances) and state tax adjustments to reflect income tax returns as filed, net of federal income tax effects; (ii) earnings/losses from unconsolidated affiliates where we anticipate receiving dividends; and (iii) non-deductible dividends on the preferred stock of subsidiaries.

We have not historically recorded U.S. deferred tax assets or liabilities on book versus tax basis differences for a substantial portion of our international investments based on our intent to indefinitely reinvest earnings from these investments outside the U.S. However, based on current sales negotiations on certain of our Asian power assets, we currently expect to receive these sales proceeds within the U.S. During the six months ended June 30, 2005, our effective tax rate was impacted upon recording net deferred tax assets on book versus tax basis differences in these investments based on the status of these negotiations. We also recorded deferred tax benefits on the sale of an Indian power asset. As of June 30, 2005, and December 31, 2004, we have deferred tax assets of $97 million and $6 million and deferred tax liabilities of $39 million in both periods related to these investments.

In 2004, our overall effective tax rate on continuing operations was impacted by impairments of certain of our foreign investments for which there was either a partial or no corresponding tax benefit. Additionally, for the six month period ended June 30, 2004, income tax expense in a period in which there was a pre-tax loss resulted in a negative effective tax rate.

7. Earnings Per Share

We have excluded 73 million and 16 million of potentially dilutive securities for the quarters and six months ended June 30, 2005 and 2004, from the determination of diluted earnings per share (as well as their related income statement impacts) due to their antidilutive effect on income (loss) per common share. The excluded securities included convertible preferred stock and restricted stock in 2005 and stock options, trust preferred securities and convertible debentures in 2005 and 2004.

8. Price Risk Management Activities

The following table summarizes the carrying value of the derivatives used in our price risk management activities as of June 30, 2005 and December 31, 2004. In the table, derivatives designated as hedges primarily consist of instruments used to hedge our natural gas and oil production. Derivatives from power contract restructuring activities relate to power purchase and sale agreements that arose from our activities in that business and other commodity-based derivative contracts relate to our historical energy trading activities. Interest rate and foreign currency hedging derivatives consist of instruments to hedge our interest rate and currency risks on long-term debt.

	June 30, 2005	December 31, 2004
	(In millions)	
Net assets (liabilities)		
Derivatives designated as hedges	$(640)	$(536)
Derivatives from power contract restructuring activities(1)	60	665
Other commodity-based derivative contracts(1)	36	(61)
Total commodity-based derivatives	(544)	68
Interest rate and foreign currency hedging derivatives(2)	13	239
Net assets (liabilities) from price risk management activities(3)	$(531)	$ 307

(1) Derivatives from power contract restructuring activities as of December 31, 2004 includes $596 million of derivative contracts sold in connection with the sale of Cedar Brakes I and II in March 2005. In connection with this sale, we also assigned or terminated other commodity-based derivatives that had a fair value liability of $240 million as of December 31, 2004.

(2) In March 2005, we repurchased approximately €528 million of debt, of which €375 million was hedged with interest rate and foreign currency derivatives. As a result of the repurchase, we removed the hedging designation on these derivatives and cancelled

substantially all of the contracts. We recorded a gain of approximately $2 million during the first quarter of 2005 upon the reversal of the related accumulated other comprehensive income associated with these derivatives.

(3) Included in both current and non-current assets and liabilities on the balance sheet.

Our derivative contracts are recorded in our financial statements at fair value. The best indication of fair value is quoted market prices. However, when quoted market prices are not available, we estimate the fair value of those derivative contracts. Prior to April 2005, we used commodity prices from market-based sources such as the New York Mercantile Exchange for forward pricing data within two years. For forecasted settlement prices beyond two years, we used a combination of commodity pricing data from market-based sources and other independent pricing sources to develop price curves. These curves were then used to estimate the value of settlements in future periods based on the contractual settlement quantities and dates. Finally, we discounted these estimated settlement values using a LIBOR curve for the majority of our derivative contracts or by using an adjusted risk free rate for our restructured power contracts.

Effective April 1, 2005, we began using new forward pricing data provided by Platts Research and Consulting, our independent pricing source, due to their decision to discontinue the publication of the pricing data we had been utilizing in prior periods. In addition, due to the nature of the new forward pricing data, we extended the use of that data over the entire contractual term of our derivative contracts. Previously, we only used Platts' pricing data to value our derivative contracts beyond two years. Based on our analysis, we do not believe the overall impact of this change in estimate was material to our results for the period.

9. Debt, Other Financing Obligations and Other Credit Facilities

We had the following long-term and short-term borrowings and other financing obligations:

	June 30, 2005	December 31, 2004
	(In millions)	
Short-term financing obligations, including current maturities	$ 1,099(1)	$ 955
Long-term financing obligations	16,379	18,241
Total	$17,478	$19,196

(1) Includes $599 million of zero coupon debentures that the holders may require us to redeem in February 2006, prior to their stated maturities.

Long-Term Financing Obligations

From January 1, 2005 through the date of this filing, we had the following changes in our long-term financing obligations:

Company	Type	Interest Rate	Book Value	Cash Received/ Paid
			(In millions)	
Issuances				
Colorado Interstate Gas Company (CIG)	Senior Notes due 2015	5.95%	$ 200	$ 197
Cheyenne Plains Gas Pipeline Company[(1)]	Non-recourse term loan due 2015	Variable	266	261
	Increases through June 30, 2005		$ 466	$ 458
Repayments, repurchases, retirements and other				
El Paso	Zero coupon debenture[(2)]	—	$ 236	$ 237
El Paso	Notes	6.88%	167	167
Cedar Brakes I[(3)]	Non-recourse notes	8.5%	241	15
Cedar Brakes II[(3)]	Non-recourse notes	9.88%	334	14
El Paso[(4)]	Euro notes	5.75%	695	722
CIG	Debentures	10.00%	180	180
Other	Long-term debt	Various	331	228
	Decreases through June 30, 2005		$2,184	$1,563
Other	Long-term debt		5	5
	Decreases through filing date		$2,189	$1,568

(1) In addition to the borrowing, we have an associated letter of credit facility for $12 million, under which we issued $6 million of letters of credit in May 2005. We also concurrently entered into swaps to convert the variable interest rate on approximately $213 million of this debt to a current fixed rate of 5.94 percent.

(2) This security has a yield-to-maturity of approximately four percent.

(3) Prior to the sale of Cedar Brakes I and II, we made $29 million of scheduled principal repayments. Upon the sale of these entities in March 2005, the remaining balance of the debt was eliminated.

(4) We recorded a $26 million loss on the early extinguishment of this debt.

On July 1, 2005, we remarketed our $272 million, 6.14% Senior Notes that were due August 16, 2007. The remarketed notes bear interest at 7.625% and are due August 16, 2007. The proceeds from the offering are being held by a collateral agent in connection with our 9.0% equity security units. For a further discussion of our equity security units, see our 2004 Annual Report on Form 10-K, as amended. The equity security unit holders are obligated to fulfill their commitment to purchase approximately 13.6 million shares of our common stock on August 16, 2005. At that time, we will issue the common stock and will receive approximately $272 million in cash.

We recorded accretion expense on our zero coupon bonds of $6 million and $9 million during the second quarter of 2005 and 2004, and $13 million and $18 million during the six months ended June 30, 2005 and 2004. These amounts are added to the principal balance each period and are included in our long term debt. We account for redemption of zero coupon debentures as a financing activity in our statement of cash flows, which included this accretion. During the six months ended June 30, 2005 we redeemed $236 million of our zero coupon debentures of which $34 million represented increased principal due to the accretion of interest on the debentures.

Credit Facilities

As of June 30, 2005, we had borrowing capacity under our $3 billion credit agreement of $0.4 billion. Amounts outstanding under the credit agreement were a $1.2 billion term loan and $1.4 billion of letters of credit. For a further discussion of our $3 billion credit agreement, our other credit facilities and their related restrictive covenants, see our 2004 Annual Report on Form 10-K, as amended.

The availability of borrowings under our $3 billion credit agreement and our ability to incur additional debt is subject to various financial and non-financial covenants and restrictions. There have been no substantial changes to our restrictive covenants from those described in our Annual Report of Form 10-K, as amended. However, El Paso CGP Company is no longer required to maintain a minimum net worth of $850 million due to the repayment of the debt covered by the indenture.

Letters of Credit

As of June 30, 2005, we had outstanding letters of credit of approximately $1.5 billion, of which $1.4 billion was outstanding under our $3 billion credit agreement and $102 million was supported with cash collateral. Included in our outstanding letters of credit were approximately $1.0 billion of letters of credit securing our recorded obligations related to price risk management activities.

10. Commitments and Contingencies

Legal Proceedings

Western Energy Settlement. In June 2003, we entered into various agreements to resolve the principal litigation, investigations, claims, and regulatory proceedings arising out of the sale or delivery of natural gas and/or electricity to the western United States (the Western Energy Settlement). In April 2005, we paid the remaining $442 million due under a 20 year cash payment obligation that arose under certain of these agreements and recorded an additional $59 million charge in the first quarter of 2005 resulting from this prepayment. These agreements also included a Joint Settlement Agreement or JSA where we agreed to certain conditions regarding service and facilities on El Paso Natural Gas Company (EPNG). In June 2003, El Paso, the California Public Utilities Commission (CPUC), Pacific Gas and Electric Company, Southern California Edison Company, and the City of Los Angeles filed the JSA with the FERC. In November 2003, the FERC approved the JSA with minor modifications. Our east of California shippers filed requests for rehearing, which were denied by the FERC on March 30, 2004. Certain shippers have appealed the FERC's ruling to the U.S. Court of Appeals for the District of Columbia, where this matter is pending. This appeal has been fully briefed but has not yet been set for oral argument.

Shareholder/Derivative/ERISA Litigation

Shareholder Litigation. Twenty-eight purported shareholder class action lawsuits have been pending since 2002 and are consolidated in federal court in Houston, Texas. This consolidated lawsuit, which alleges violations of federal securities laws against us and several of our current and former officers and directors, includes allegations regarding the accuracy or completeness of press releases and other public statements made during the class period from 2001 through early 2004 related to wash trades, mark-to-market accounting, off-balance sheet debt, the overstatement of oil and gas reserves and manipulation of the California energy market. Discovery in the consolidated lawsuit is currently stayed.

Derivative Litigation. Since 2002, six shareholder derivative actions have also been filed. Three of the actions allege the same claims as in the consolidated shareholder class action suit described above, with one of the actions including a claim for compensation disgorgement against certain individuals. Discovery in two of those three lawsuits are stayed in federal court in Houston, Texas. The third, originally pending in Delaware, was voluntarily dismissed by the plaintiffs in July 2005. The Delaware plaintiffs' claims will be pursued with two other actions consolidated in state court in Houston, Texas. The state court lawsuits generally allege that the manipulation of California gas prices exposed us to claims of antitrust conspiracy, FERC penalties and erosion of share value and are set for trial in January 2006. The sixth derivative action, *Laties v. El Paso, et al.* was filed in Delaware in April 2005 against our former Chief Executive Officer, William Wise and current and former members of our Board of Directors. This derivative action seeks restitution of the 2001 incentive compensation paid to William Wise due to the Company's restatement of its financial statements for that year.

ERISA Class Action Suits. In December 2002, a purported class action lawsuit entitled *William H. Lewis, III v. El Paso Corporation, et al.* was filed in the U.S. District Court for the Southern District of

Texas alleging generally that our direct and indirect communications with participants in the El Paso Corporation Retirement Savings Plan included misrepresentations and omissions that caused members of the class to hold and maintain investments in El Paso stock in violation of the Employee Retirement Income Security Act (ERISA). That lawsuit was subsequently amended to include allegations relating to our reporting of natural gas and oil reserves. Discovery in this lawsuit is currently stayed.

We and our representatives have insurance coverages that are applicable to each of these shareholder, derivative and ERISA lawsuits. There are certain deductibles and co-pay obligations under some of those insurance coverages for which we have established certain accruals we believe are adequate.

Cash Balance Plan Lawsuit. In December 2004, a lawsuit entitled *Tomlinson, et al. v. El Paso Corporation and El Paso Corporation Pension Plan* was filed in U.S. District Court for Denver, Colorado. The lawsuit seeks class action status and alleges that the change from a final average earnings formula pension plan to a cash balance pension plan, the accrual of benefits under the plan, and the communications about the change violate the ERISA and/or the Age Discrimination in Employment Act. Our costs and legal exposure related to this lawsuit are not currently determinable.

Retiree Medical Benefits Matters. We currently serve as the plan administrator for a medical benefits plan that covers a closed group of retirees of the Case Corporation who retired on or before June 30, 1994. Case was formerly a subsidiary of Tenneco, Inc. that was spun off prior to our acquisition of Tenneco in 1996. In connection with the Tenneco-Case Reorganization Agreement of 1994, Tenneco assumed the obligation to provide certain medical and prescription drug benefits to eligible retirees and their spouses. We assumed this obligation as a result of our merger with Tenneco. However, we believe that our liability for these benefits is limited to certain maximums, or caps, and costs in excess of these maximums are assumed by plan participants. In 2002, we and Case were sued by individual retirees in federal court in Detroit, Michigan in an action entitled *Yolton et al. v. El Paso Tennessee Pipeline Company and Case Corporation.* The suit alleges, among other things, that El Paso and Case violated ERISA, and that they should be required to pay all amounts above the cap. Although such amounts will vary over time, the amounts above the cap have recently been approximately $1.8 million per month. Case further filed claims against El Paso asserting that El Paso is obligated to indemnify, defend, and hold Case harmless for the amounts it would be required to pay. In February 2004, a judge ruled that Case would be required to pay the amounts incurred above the cap. Furthermore, in September 2004, a judge ruled that pending resolution of this matter, El Paso must indemnify and reimburse Case for the monthly amounts above the cap. These rulings have been appealed. In the meantime, El Paso will indemnify Case for any payments Case makes above the cap. While we believe we have meritorious defenses to the plaintiffs' claims and to Case's crossclaim, if we were required to ultimately pay for all future amounts above the cap, and if Case were not found to be responsible for these amounts, our exposure could be as high as $400 million, on an undiscounted basis.

Natural Gas Commodities Litigation. Beginning in August 2003, several lawsuits were filed against El Paso and El Paso Marketing L.P. (EPM), formerly El Paso Merchant Energy L.P., our affiliate, in which plaintiffs alleged, in part, that El Paso, EPM and other energy companies conspired to manipulate the price of natural gas by providing false price reporting information to industry trade publications that published gas indices. Those cases, all filed in the United States District Court for the Southern District of New York, are as follows: *Cornerstone Propane Partners, L.P. v. Reliant Energy Services Inc., et al.*; *Roberto E. Calle Gracey v. American Electric Power Company, Inc., et al.*; and *Dominick Viola v. Reliant Energy Services Inc., et al.* In December 2003, those cases were consolidated with others into a single master file in federal court in New York for all pre-trial purposes. In September 2004, the court dismissed El Paso from the master litigation. EPM and approximately 27 other energy companies remain in the litigation. In January 2005, a purported class action lawsuit styled *Leggett et al. v Duke Energy Corporation et al.* was filed against El Paso, EPM and a number of other energy companies in the Chancery Court of Tennessee for the Twenty-Fifth Judicial District at Somerville on behalf of all residential and commercial purchasers of natural gas in the state of Tennessee. Plaintiffs allege the defendants conspired to manipulate the price of natural gas by providing false price reporting information to industry trade publications that published gas indices. We have also had similar purported class claims filed in the U.S. District Court for the Eastern District of California by and on behalf of commercial and residential customers in that state. The case of *Texas-Ohio Energy, Inc. v. CenterPoint Energy, Inc., et al.* was filed in November 2003; *Fairhaven Power v. El Paso Corporation, et al.* was filed in September 2004; *Utility Savings and Refund Services, et al. v. Reliant Energy, et al.* was filed in December 2004; *Abelman Art Glass, et al. v. Encana Corporation, et al.* was filed in December 2004; and *Ever-Bloom Inc. v. AEP Energy Services Inc. et al* was filed in June 2005, and *FLI Liquidating Trust v. Oneok Inc.* was filed in July 2005. The defendants' motion to dismiss in the *Texas-Ohio* matter has been granted and similar motions are anticipated in the other cases. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

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 due to the alleged mismeasurement. The plaintiff seeks royalties along with interest, expenses, and punitive damages. The plaintiff also seeks injunctive relief with regard to future 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). Motions to dismiss were argued before a representative appointed by the court. In May 2005, the representative issued its recommendation, which if adopted by the district court judge, will result in the dismissal on jurisdictional grounds of six of the seven *Qui Tam* actions filed by Grynberg against El Paso subsidiaries. The seventh case involves only a few midstream entities owned by El Paso, which have meritorious defenses to the underlying claims. If the district court judge adopts the representative's recommendations, an appeal by the plaintiff of the district court's order is likely. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Will Price (formerly Quinque). A number of our subsidiaries are named as defendants in *Will Price, et al. v. Gas Pipelines and Their Predecessors, et al.,* filed in 1999 in the District Court of Stevens County, Kansas. Plaintiffs allege that the defendants mismeasured natural gas volumes and heating content of natural gas on non-federal and non-Native American lands and seek to recover royalties that they contend they 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, attorneys' 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 of a nationwide class of natural gas working interest owners and natural gas royalty owners was denied in April 2003. Plaintiffs were granted leave to file a Fourth Amended Petition, which narrows the proposed class to royalty owners in wells in Kansas, Wyoming and Colorado and removes claims as to heating content. A second class action petition has since been filed as to the heating content claims. Motions for class certification have been briefed and argued in both proceedings, and the parties are awaiting the court's ruling. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Bank of America. We are a named defendant, along with Burlington Resources, Inc., in two class action lawsuits styled as *Bank of America, et al. v. El Paso Natural Gas Company, et al.,* and *Deane W. Moore, et al. v. Burlington Northern, Inc., et al.,* each filed in 1997 in the District Court of Washita County, State of Oklahoma and subsequently consolidated by the court. The plaintiffs have filed reports alleging damages of approximately $480 million which includes alleged royalty underpayments from 1982 to the present on natural gas produced from specified wells in Oklahoma, plus interest from the time such amounts were allegedly due. The plaintiffs have also requested punitive damages. The court has certified the plaintiff classes of royalty and overriding royalty interest owners. The consolidated class action has been set for trial in the fourth quarter of 2005. While Burlington accepted our tender of the defense of these cases in 1997, pursuant to the spin-off agreement entered into in 1992 between EPNG and Burlington Resources, Inc., and had been defending the matter since that time, at the end of 2003 it asserted contractual claims for indemnity against us. A third action, styled *Bank of America, et al. v. El Paso Natural Gas and Burlington Resources Oil and Gas Company,* was filed in October 2003 in the District Court of Kiowa County, Oklahoma asserting similar claims as to specified shallow wells in Oklahoma, Texas and New Mexico. Defendants succeeded in transferring this action to Washita County. A class has not been certified. We have filed an action styled *El Paso Natural Gas Company v. Burlington Resources, Inc. and Burlington Resources Oil and Gas Company, L.P.* against Burlington in state court in Harris County relating to the indemnity issues between Burlington and us. That action is currently stayed by agreement of the parties. We believe we have substantial defenses to the plaintiffs' claims as well as to the claims for indemnity by Burlington. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Araucaria. We own a 60 percent interest in a 484 MW gas-fired power project known as the Araucaria project located near Curitiba, Brazil. The Araucaria project has a 20-year power purchase agreement (PPA) with a government-controlled regional utility. In December 2002, the utility ceased making payments to the project and, as a result, the Araucaria project and the utility are currently involved in international arbitration over the PPA, which is scheduled for hearing in the first quarter of 2006. A Curitiba court has ruled that the arbitration clause in the PPA is invalid. The project company is appealing this ruling. Our investment in the Araucaria project was $187 million at June 30, 2005. We have political risk insurance that covers a substantial portion of our investment in the project. Based on the future outcome of our dispute under the PPA and depending on our ability to collect amounts from the utility or under our political risk insurance policies, we could be required to write down the value of our investment.

Macae. We own a 928 MW gas-fired power plant known as the Macae project located near the city of Macae, Brazil. The Macae project revenues are derived from sales to the spot market, bilateral contracts and minimum capacity and revenue payments. The minimum capacity and energy revenue payments of the Macae project are paid by Petrobras until August 2007 under a participation agreement. Petrobras has filed a notice of arbitration with an international arbitration institution that effectively seeks rescission of the participation agreement and reimbursement of a portion of the capacity payments that it has made. If such claim were successful, it would result in a termination of the minimum revenue payments as well as Petrobras' obligation to provide a firm gas supply to the project through 2012. Beginning in December 2004, and continuing through the second quarter of 2005, Petrobras has failed to make payments that were due under the participation agreement. Various actions have been filed in Brazilian courts and before the arbitration panel to address Petrobras' payment obligations during the pendency of the arbitration proceedings. Although various appellate proceedings in such actions are outstanding, currently the arbitration panel has required Petrobras to pay past due amounts and additional amounts owed during the arbitration process, subject to Macae's obligation to post a bank guarantee as security for any repayment obligation if Petrobras were to prevail on the merits. Due to this ongoing dispute, during the first six months of 2005 we have not recognized approximately $99 million of revenues under our participation agreement, because of the uncertainty about their collectibility. We believe we have substantial defenses to the claims of Petrobras and will vigorously defend our legal rights. In addition, we will continue to seek reasonable negotiated settlements of this dispute, including the restructuring of the participation agreement or the sale of the plant. Macae has non-recourse debt of approximately $276 million at June 30, 2005, and Petrobras' non-payment has created an event of default under the applicable loan agreements. As a result, we have classified the entire $276 million of debt as current. We also have restricted cash balances of approximately $14 million as of June 30, 2005, which are reflected in current assets, related to required debt service reserve balances, debt service payment accounts and funds held for future distribution by Macae. We have also issued cash collateralized letters of credit of approximately $47 million as part of funding the required debt service reserve accounts. The restricted cash related to these letters of credit has also been classified as a current asset. In light of the default of Petrobras under the participation agreement and the potential inability of Macae to continue to make ongoing payments under its loan agreements, one or more of the lenders could exercise certain remedies under the loan agreements in the future, one of which could be an acceleration of the amounts owed under the loan agreements which could ultimately result in the lenders foreclosing on the Macae project.

In light of the pending arbitration proceedings, and as a result of continued negotiations and discussions with Petrobras regarding this dispute, we may sell our investment in the Macae power facility to Petrobras in connection with the eventual resolution of this dispute or exchange our interest in the plant for Brazilian production properties owned by Petrobras. We recorded a $276 million impairment charge on our investment and also reserved $18 million of related receivables in the second quarter of 2005 based on information regarding the potential value we may receive from the resolution of this matter. In the event that the lenders call the loans and ultimately foreclose on the project, we may incur additional losses of up to approximately $204 million. As new information becomes available or future material developments occur, we will reassess the carrying value of our interests in this project.

MTBE. In compliance with the 1990 amendments to the Clean Air Act, we used the gasoline additive methyl tertiary-butyl ether (MTBE) in some of our gasoline. We have also produced, bought, sold and distributed MTBE. A number of lawsuits have been filed throughout the U.S. regarding MTBE's potential impact on water supplies. We and some of our subsidiaries are among the defendants in over 60 such lawsuits. As a result of a ruling issued on March 16, 2004, these suits have been consolidated for pre-trial purposes in multi-district litigation in the U.S. District Court for the Southern District of New York. The plaintiffs, certain state attorneys general and various water districts, seek remediation of their groundwater, prevention of future contamination, a variety of compensatory damages, punitive damages, attorney's fees, and court costs. The plaintiff states of California and New Hampshire have filed an appeal to the 2nd Circuit Court of Appeals challenging the removal of the cases from state to federal court. That appeal is pending. On April 20, 2005, the judge denied a motion by defendants to dismiss the lawsuits. In that opinion the Court recognized, for certain states, a potential commingled product market share basis for collective liability. Our costs and legal exposure related to these lawsuits are not currently determinable.

Wise Arbitration. William Wise, our former Chief Executive Officer, initiated an arbitration proceeding alleging that we breached his employment agreement, as well as several other alleged agreements by failing to make certain payments to him following his departure from El Paso in 2003. Although Mr. Wise initially sought approximately $20 million in additional compensation, Mr. Wise revised his claims and sought cash compensation in excess of $15 million, as well as injunctive relief that would require us to make certain future payments. The arbitration panel issued an interim decision in July 2005 generally finding that Mr. Wise was not entitled to any payments other than those set forth in his employment agreement that governed his post employment compensation. A final decision will be issued following additional briefings.

Government Investigations

Power Restructuring. El Paso has cooperated with the SEC with regard to an investigation of our power plant contract restructurings and the related disclosures and accounting treatment for the restructured power contracts, including, in particular, the Eagle Point restructuring transaction completed in 2002. In July 2005, we were informed by the staff of the SEC that they do not intend to recommend any enforcement action concerning this investigation.

Wash Trades. In June 2002, we received an informal inquiry from the SEC regarding the issue of round trip trades. Although we do not believe any round trip trades occurred, we submitted data to the SEC in July 2002. In July 2002, we received a federal grand jury subpoena for documents concerning round trip or wash trades. We have complied with those requests. We have also cooperated with the U.S. Attorney regarding an investigation of specific transactions executed in connection with hedges of our natural gas and oil production and the restatement of such hedges. On May 24, 2005, we received a subpoena from the SEC requesting the production of documents related to such production hedges. We are cooperating with the SEC investigation.

Price Reporting. In October 2002, the FERC issued data requests regarding price reporting of transactional data to the energy trade press. We provided information to the FERC, the Commodity Futures Trading Commission (CFTC) and the U.S. Attorney in response to their requests. In the first quarter of 2003, we announced a settlement with the CFTC of the price reporting matter providing for the payment of a civil monetary penalty by EPM of $20 million, $10 million of which is payable in 2006, without admitting or denying the CFTC holdings in the order. We are continuing to cooperate with the U.S. Attorney's investigation of this matter.

Reserve Revisions. In March 2004, we received a subpoena from the SEC requesting documents relating to our December 31, 2003 natural gas and oil reserve revisions. We have also received federal grand jury subpoenas for documents with regard to these reserve revisions and we cooperated with the U.S. Attorney's investigation related to this matter. In June 2005, we were informed that the U.S. Attorney's office closed this investigation and will not pursue prosecution at this time. We will continue to cooperate with the SEC in its investigation related to such reserve revisions.

Iraq Oil Sales. In September 2004, The Coastal Corporation (now known as El Paso CGP Company, which we acquired in January 2001) received a subpoena from the grand jury of the U.S. District Court for the Southern District of New York to produce records regarding the United Nations' Oil for Food Program governing sales of Iraqi oil. The subpoena seeks various records related to transactions in oil of Iraqi origin during the period from 1995 to 2003. In November 2004, we received an order from the SEC to provide a written statement and to produce certain documents in connection with The Coastal Corporation's and El Paso's participation in the Oil for Food Program. In June 2005, we received an additional request for documents and information from the SEC. We have also received informal requests for information and documents from the United States Senate's Permanent Subcommittee of Investigations and the House of Representatives International Relations Committee related to Coastal's purchases of Iraqi crude under the Oil for Food Program. We are cooperating with the U.S. Attorney's, the SEC's, the Senate Subcommittee's, and the House Committee's investigations of this matter.

Carlsbad. In August 2000, a main transmission line owned and operated by EPNG ruptured at the crossing of the Pecos River near Carlsbad, New Mexico. Twelve individuals at the site were fatally injured. In June 2001, the U.S. Department of Transportation's Office of Pipeline Safety (DOT) issued a Notice of Probable Violation and Proposed Civil Penalty to EPNG. The Notice alleged violations of DOT regulations, proposed fines totaling $2.5 million and proposed corrective actions. In April 2003, the National Transportation Safety Board (NTSB) issued its final report on the rupture, finding that the rupture was probably caused by internal corrosion that was not detected by EPNG's corrosion control program. In December 2003, this matter was referred by the DOT to the Department of Justice (DOJ). We recently entered into a tolling agreement with the DOJ to attempt to reach resolution of this civil proceeding. In addition, we, EPNG and several of its current and former employees had received several federal grand jury subpoenas for documents or testimony related to the Carlsbad rupture. In July 2005, we were informed by the DOJ that the United States is not pursuing any criminal prosecutions associated with the rupture.

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. There are also other regulatory rules and orders in various stages of adoption, review and/or implementation, none of which we believe will have a material impact on us.

Rates and Regulatory Matters

Selective Discounting Notice of Inquiry (NOI). In November 2004, the FERC issued a NOI seeking comments on its policy regarding selective discounting by natural gas pipelines. In May 2005, the FERC issued an order reaffirming its prior practice of permitting pipelines to adjust their ratemaking throughput downward in rate cases to reflect discounts given by pipelines for competitive reasons when the discount is given to meet competition from another natural gas pipeline.

EPNG Rate Case. In June 2005, EPNG filed a rate case with the FERC proposing an increase in revenues of 10.6 percent or $56 million over current tariff rates, new services and revisions to certain terms and conditions of existing services, including the adoption of a fuel tracking mechanism. The rate case would be effective January 1, 2006. In addition, the reduced tariff rates provided to EPNG's former full requirements (FR) customers under the terms of our FERC approved systemwide capacity allocation proceeding will expire on January 1, 2006. The combined effect of the proposed increase in tariff rates and the expiration of the lower rates to EPNG's FR customers are estimated to increase our revenues by approximately $138 million. In July 2005, the FERC accepted certain of the proposed tariff revisions, including the adoption of a fuel tracking mechanism and set the rate case for hearing and technical conference. The FERC directed the scheduling of the technical conference within 150 days of the order and held the hearing pending resolution of the various matters identified for consideration at the technical conference. We anticipate continued discussions with intervening parties and are uncertain of the settlement of this rate case.

SNG Rate Case. In August 2004, SNG filed a rate case with the FERC seeking an annual rate increase of $35 million, or 11 percent in jurisdictional rates and certain revisions to its effective tariff regarding terms and conditions of service. In April 2005, SNG reached a tentative settlement in principle that would resolve all issues in our rate proceeding, and filed the negotiated offer of settlement with the FERC on April 29, 2005. SNG implemented the settlement rates on an interim basis as of March 1, 2005 as negotiated rates with all shippers which elected to be consenting parties under the rate settlement. In an order issued in July 2005, the FERC approved the settlement. Under the terms of the settlement, SNG reduced the proposed increase in its base tariff rates by approximately $21 million; reduced its fuel retention percentage and agreed to an incentive sharing mechanism to encourage additional fuel savings; received approval for capital maintenance tracker that will allow it to recover costs through its rates; adjusted the rates for its South Georgia facilities and agreed to file its next general rate case no earlier than March 1, 2009 and no later than March 31, 2010. The settlement also provided for changes regarding SNG's terms and conditions of service. We do not expect the settlement to have a material impact on our future financial results. In addition, as a result of the contract extensions required by the settlement, the contract terms for firm service now average approximately seven years.

Other Contingencies

Navajo Nation. Nearly 900 looped pipeline miles of the north mainline of our EPNG pipeline system are located on property inside the Navajo Nation. We currently pay approximately $2 million per year for the real property interests, such as easements, leases and rights-of-way located on Navajo Nation trust lands. These real property interests are scheduled to expire in October 2005. We are in negotiations with the Navajo Nation to obtain their consent to renew these interests, but the Navajo Nation has made a demand of more than ten times the existing fee. We will continue to negotiate in order to reach an agreement on a renewal, but we are also exploring other options including potentially developing collaborative projects to benefit the Navajo Nation in lieu of cash payments. If we are unable to reach a new consent agreement with the Navajo Nation (which is arguably required for renewal of the U.S. Department of the Interior's extension of EPNG's current easement across trust lands) the impact is uncertain. Historically, we have continued renewal negotiations with the Navajo Nation substantially beyond the prior easement's expiration, without litigation or interruption to our operations. As our renewal efforts continue, we may incur litigation and other costs and, ultimately, higher consent fees. Although the FERC has rejected a request made in the rate case filed on June 25, 2005 for a tracking mechanism that would have provided an assurance of recovery of the cost of the Navajo right-of-way, the FERC did invite EPNG to seek permission to include the cost of the right-of-way in its pending rate case if the final cost becomes known and measurable within a reasonable time after the close of the test period on December 31, 2005.

Brazilian Matters. We own a number of interests in various production properties, power and pipeline assets in Brazil, including our Macae project discussed previously. Our total investment in Brazil was approximately $1.3 billion as of June 30, 2005. In a number of our assets and investments, Petrobras either serves as a joint owner, a customer or a shipper to the asset or project. Although we have no material current disputes with Petrobras with regard to the ownership or operation of our production and pipeline assets, current disputes on the Macae power plant between us and Petrobras may negatively impact these investments and the impact could be material. In addition, although the Macae power plant is currently dispatching only small quantities of electricity, a recent rupture in the local distribution company's pipeline that supplies it gas has resulted in the plant temporarily being unable to generate electricity. We are currently assessing the time it will take for the pipeline to be repaired. We also own an investment in the Porto Velho power plant. The Porto Velho project is in the process of negotiating certain provisions of its power purchase agreements (PPA) with Eletronorte, including the amount of installed capacity, energy prices, take or pay levels, the term of the first PPA and other issues. In addition, in October 2004, the project experienced an outage with a steam turbine which resulted in a partial reduction in the plant's capacity. The project expects to repair the steam turbine by the first quarter of 2006. We are uncertain what impact this outage will have on the PPAs.

Although the current terms of the PPAs and the ongoing contract negotiations do not indicate an impairment of our investment, we may be required to write down the value of our investment if these negotiations are resolved unfavorably. Our investment in Porto Velho was approximately $316 million at June 30, 2005.

For each of our outstanding legal and other contingent 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. While the outcome of these matters cannot be predicted with certainty and there are still uncertainties related to the costs we may incur, based upon our evaluation and experience to date, we believe we have established appropriate reserves for these matters. However, it is possible that new information or future developments could require us to reassess our potential exposure related to these matters and adjust our accruals accordingly. As of June 30, 2005, we had approximately $172 million accrued, net of related insurance receivables, for all outstanding legal and other contingent matters.

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, 2005, we had accrued approximately $371 million, including approximately $358 million for expected remediation costs and associated onsite, offsite and groundwater technical studies, and approximately $13 million for related environmental legal costs, which we anticipate incurring through 2027. Of the $371 million accrual, $100 million was reserved for facilities we currently operate, and $271 million was reserved for non-operating sites (facilities that are shut down or have been sold) and Superfund sites.

Our reserve estimates range from approximately $371 million to approximately $531 million. Our accrual represents a combination of two estimation methodologies. First, where the most likely outcome can be reasonably estimated, that cost has been accrued ($82 million). Second, where the most likely outcome cannot be estimated, a range of costs is established ($289 million to $449 million) and if no one amount in that range is more likely than any other, the lower end of the expected range has been accrued. By type of site, our reserves are based on the following estimates of reasonably possible outcomes.

	June 30, 2005	
Sites	**Expected**	**High**
	(In millions)	
Operating	$100	$111
Non-operating	244	374
Superfund	27	46
Total	$371	$531

Below is a reconciliation of our accrued liability from January 1, 2005, to June 30, 2005 (in millions):

Balance as of January 1, 2005	$380
Additions/adjustments for remediation activities	15
Payments for remediation activities	(26)
Other changes, net	2
Balance as of June 30, 2005	$371

For the last six months of 2005, we estimate that our total remediation expenditures will be approximately $43 million. In addition, we expect to make capital expenditures for environmental matters of approximately $92 million in the aggregate for the years 2005 through 2009. These expenditures primarily relate to compliance with clean air regulations.

Polychlorinated Biphenyls (PCB) Cost Recoveries. Pursuant to a consent order executed by Tennessee Gas Pipeline (TGP), our subsidiary, in May 1994, with the EPA, TGP has been conducting various remediation activities at certain of its compressor stations associated with the presence of PCBs, and certain other hazardous materials. In May 1995, following negotiations with its customers, TGP filed an agreement with the FERC that established a mechanism for recovering a substantial portion of the environmental costs identified in its PCB remediation project. The agreement, which was approved by the FERC in November 1995, provided for a PCB surcharge on firm and interruptible customers' rates to pay for eligible remediation costs, with these surcharges to be collected over a defined collection period. TGP has received approval from the FERC to extend the collection period, which is now currently set to expire in June 2006. The agreement also provided for bi-annual audits of eligible costs. As of June 30, 2005, TGP had pre-collected PCB costs by approximately $129 million. The pre-collected amount will be reduced by future eligible costs incurred for the remainder of the remediation project. To the extent actual eligible expenditures are less than the amounts pre-collected, TGP will refund to its customers the difference, plus carrying charges incurred up to the date of the refunds. As of June 30, 2005, TGP has recorded a regulatory liability (included in other non-current liabilities on its balance sheet) of $102 million for the estimated future refund obligations.

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 48 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, 2005, we have estimated our share of the remediation costs at these sites to be between $27 million and $46 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 Superfund 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, regulations, and orders of regulatory agencies, as well as claims for damages to property and the environment or injuries to employees and other persons 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 related to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe our reserves are adequate.

Guarantees

We are involved in various joint ventures and other ownership arrangements that sometimes require additional financial support that results in the issuance of financial and performance guarantees. See our 2004 Annual Report on Form 10-K, as amended, for a description of these commitments. As of June 30, 2005, we had approximately $28 million of both financial and performance guarantees not otherwise reflected in our financial statements. We also periodically provide indemnification arrangements related to assets or businesses we have sold. As of June 30, 2005, we had accrued $56 million related to these arrangements.

11. Retirement Benefits

The components of net benefit cost for our pension and postretirement benefit plans for the periods ended June 30 are as follows:

	Quarters Ended June 30,				Six Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
	2005	2004	2005	2004	2005	2004	2005	2004
	(In millions)				(In millions)			
Service cost	$ 6	$ 8	$—	$—	$ 12	$ 16	$—	$—
Interest cost	29	30	8	8	58	61	15	16
Expected return on plan assets	(42)	(47)	(3)	(3)	(84)	(95)	(6)	(6)
Amortization of net actuarial loss	16	12	—	1	32	24	—	2
Amortization of transition obligation	—	—	2	2	—	—	4	4
Amortization of prior service cost[1]	(1)	(1)	—	—	(2)	(2)	—	—
Net benefit cost	$ 8	$ 2	$ 7	$ 8	$ 16	$ 4	$13	$16

[1] As permitted, the amortization of any prior service cost is determined using a straight-line amortization of the cost over the average remaining service period of employees expected to receive benefits under the plan.

In 2004, we adopted FSP No. 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003*. This pronouncement required us to record the impact of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 on our postretirement benefit plans that provide drug benefits that are covered by that legislation. The adoption of FSP No. 106-2 decreased our accumulated postretirement benefit obligation by $49 million. In addition, it reduced our net periodic benefit cost by approximately $3 million for the first six months of 2005. Our actual and expected contributions for 2005 were not reduced by subsidies under this legislation.

We made $33 million of cash contributions to our Supplemental Executive Retirement Plan (SERP) and other postretirement plans during the six months ended June 30, 2005 and 2004. We expect to contribute an additional $2 million to the SERP and $34 million to our other postretirement plans for the remainder of 2005. Contributions to our other retirement benefit plans will be less than $1 million in 2005.

12. Capital Stock

Convertible Perpetual Preferred Stock

In April 2005, we issued $750 million of convertible perpetual preferred stock. Cash dividends on the preferred stock are paid quarterly at the rate of 4.99% per annum. Each share of the preferred stock is convertible at the holder's option, at any time, subject to adjustment, into 76.7754 shares of our common stock under certain conditions. This conversion rate represents an equivalent conversion price of approximately $13.03 per share. The conversion rate is subject to adjustment based on certain events which include, but are not limited to, fundamental changes in our business such as mergers or business combinations as well as distributions of our common stock or adjustments to the current rate of dividends on our common stock. We will be able to cause the preferred stock to be converted into common stock after five years if our common stock is trading at a premium of 130 percent to the conversion price.

The net proceeds of $723 million from the issuance of the preferred stock, together with cash on hand, was used to prepay our Western Energy Settlement of approximately $442 million in April 2005, and to pay the redemption price (an aggregate of $300 million plus accrued dividends of $3 million) of the 6,000,000 outstanding shares of 8.25% Series A cumulative preferred stock of our subsidiary, El Paso Tennessee Pipeline Co. (EPTP), in May 2005.

Dividends

During the six months ended June 30, 2005, we paid dividends of approximately $51 million to common stockholders. The dividends on our common stock were treated as a reduction of additional paid-in-capital since we currently have an accumulated deficit. We have also paid dividends of approximately $26 million subsequent to June 30, 2005. On July 28, 2005, the Board of Directors declared a quarterly dividend of $0.04 per share on the company's outstanding common stock. The dividend will be payable on October 3, 2005 to shareholders of record on September 2, 2005.

On May 26, 2005 and July 28, 2005, the Board of Directors declared quarterly dividends of $10.53 and $12.47 per share on our 4.99% convertible perpetual preferred stock. The first dividend was paid on July 1, 2005 to stockholders of record on June 15, 2005. The second dividend will be payable on October 3, 2005 to stockholders of record on September 15, 2005.

We expect dividends paid on our common and preferred stock in 2005 will be taxable to our stockholders because we anticipate that these dividends will be paid out of current or accumulated earnings and profits for tax purposes.

13. Business Segment Information

Our regulated business consists of our Pipelines segment, while our non-regulated businesses consist of our Production, Marketing and Trading, Power, and Field Services segments. Our segments are strategic business units that provide a variety of energy products and services. They are managed separately as each segment requires different technology and marketing strategies. Our corporate operations include our general and administrative functions, as well as a telecommunications business and various other contracts and assets, all of which are immaterial. During the second quarter of 2005, we reclassified our south Louisiana gathering and processing assets, which were part of our Field Services segment, as discontinued operations. Our operating results for the quarter and six months ended June 30, 2005 reflect these operations as discontinued. Prior period amounts have not been adjusted as these operations were not material to prior period results or historical trends.

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. Our business operations consist of both consolidated businesses as well as substantial investments in unconsolidated affiliates. We believe EBIT is useful to our investors because it allows them to more effectively evaluate the performance of all of our businesses and investments. Also, 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. EBIT may not be comparable to measures used by other companies. Additionally, EBIT should be considered in conjunction with net income and other performance measures such as operating income or operating cash flow. Below is a reconciliation of our EBIT to our income (loss) from continuing operations for the periods ended June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
	(In millions)			
Total EBIT	$ 59	$ 498	$ 511	$ 818
Interest and debt expense	(340)	(410)	(690)	(833)
Distributions on preferred interests of consolidated subsidiaries	(3)	(6)	(9)	(12)
Income taxes	51	(48)	57	(58)
Income (loss) from continuing operations	$(233)	$ 34	$(131)	$ (85)

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

Quarter Ended June 30,	Regulated	Non-regulated					
	Pipelines	Production	Marketing and Trading	Power	Field Services	Corporate[1]	Total
			(In millions)				
2005							
Revenues from external customers	$634	$171[2]	$ 240	$ 112	$ 23	$ 24	$1,204
Intersegment revenues	19	281[2]	(261)	(3)	5	(21)	20[3]
Operation and maintenance	214	99	9	78	4	34	438
Depreciation, depletion and amortization	108	157	1	10	1	17	294
(Gain) loss on long-lived assets	(3)	—	—	361	6	(4)	360
Operating income (loss)	$262	$175	$ (32)	$(357)	$ (5)	$(36)	$ 7
Earnings (losses) from unconsolidated affiliates	38	—	—	(59)	2	—	(19)
Other income, net	9	1	2	35	—	24	71
EBIT	$309	$176	$ (30)	$(381)	$ (3)	$(12)	$ 59
2004							
Revenues from external customers	$595	$144[2]	$ 187	$ 202	$375	$ 29	$1,532
Intersegment revenues	22	286[2]	(328)	34	53	(75)	(8)[3]
Operation and maintenance	172	77	10	97	25	(8)	373
Depreciation, depletion and amortization	101	131	3	12	4	12	263
(Gain) loss on long-lived assets	—	—	—	16	6	(5)	17
Operating income (loss)	$260	$202	$(154)	$ 56	$ 7	$ (1)	$ 370
Earnings from unconsolidated affiliates	41	2	—	24	31	—	98
Other income (expense), net	7	—	2	22	(11)	10	30
EBIT	$308	$204	$(152)	$ 102	$ 27	$ 9	$ 498

(1) Includes 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. For the quarters ended June 30, 2005 and 2004, we recorded an intersegment revenue elimination of $39 million and $75 million and an operations and maintenance expense elimination of less than $1 million and $1 million, which is included in the "Corporate" column, to remove intersegment transactions.

(2) Revenues from external customers include gains and losses related to our hedging of price risk associated with our natural gas and oil production. Intersegment revenues represent sales to our Marketing and Trading segment, which is responsible for marketing our production.

(3) Relates to intercompany activities between our continuing operations and our discontinued operations.

Six Months Ended June 30,	Regulated Pipelines	Non-regulated Production	Non-regulated Marketing and Trading	Non-regulated Power	Non-regulated Field Services	Corporate[1]	Total
			(In millions)				
2005							
Revenues from external customers	$1,382	$302[2]	$ 333	$ 191	$ 65	$ 51	$2,324
Intersegment revenues	39	589[2]	(529)	(5)	11	(63)	42[3]
Operation and maintenance	417	183	19	129	3	129	880
Depreciation, depletion and amortization	219	303	2	22	2	26	574
(Gain) loss on long-lived assets	(10)	—	—	388	7	(4)	381
Operating income (loss)	$ 624	$355	$(218)	$(395)	$ (3)	$(127)	$ 236
Earnings (losses) from unconsolidated affiliates	76	—	—	(87)	182	—	171
Other income, net	21	4	3	51	—	25	104
EBIT	$ 721	$359	$(215)	$(431)	$179	$(102)	$ 511
2004							
Revenues from external customers	$1,293	$277[2]	$ 368	$ 351	$720	$ 72	$3,081
Intersegment revenues	45	599[2]	(668)	92	95	(163)	—
Operation and maintenance	352	162	23	194	51	(8)	774
Depreciation, depletion and amortization	201	271	6	28	7	25	538
(Gain) loss on long-lived assets	(1)	—	—	256	8	(8)	255
Operating income (loss)	$ 608	$405	$(329)	$(148)	$ 17	$ 6	$ 559
Earnings from unconsolidated affiliates	74	3	—	40	68	—	185
Other income (expense), net	12	—	13	41	(22)	30	74
EBIT	$ 694	$408	$(316)	$ (67)	$ 63	$ 36	$ 818

(1) Includes 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. For the six months ended June 30, 2005 and 2004, we recorded an intersegment revenue elimination of $103 million and $163 million and an operations and maintenance expense elimination of less than $1 million and $1 million, which is included in the "Corporate" column, to remove intersegment transactions.

(2) Revenues from external customers include gains and losses related to our hedging of price risk associated with our natural gas and oil production. Intersegment revenues represent sales to our Marketing and Trading segment, which is responsible for marketing our production.

(3) Relates to intercompany activities between our continuing operations and our discontinued operations.

Total assets by segment are presented below:

	June 30, 2005	December 31, 2004
	(In millions)	
Regulated		
Pipelines	$16,056	$15,988
Non-regulated		
Production	4,518	4,080
Marketing and Trading	2,718	2,404
Power	2,348	3,599
Field Services	121	686
Total segment assets	25,761	26,757
Corporate	3,722	4,520
Discontinued operations	193	106
Total consolidated assets	$29,676	$31,383

14. Investments in Unconsolidated Affiliates and Related Party Transactions

We hold investments in various unconsolidated affiliates which are accounted for using the equity method of accounting. Our principal equity method investees are international pipelines, interstate pipelines and power generation plants. Our income statement reflects our share of net earnings from unconsolidated affiliates, which includes income or losses directly attributable to the net income or loss of our equity investments as well as impairments and other adjustments. In addition, for investments we are in the process of selling, or for those that have been previously impaired, we evaluate the income generated by the investment and record an amount that we believe is realizable. For losses, we assess whether such amounts have already been considered in a related impairment. Our net ownership interest and earnings (losses) from our unconsolidated affiliates are as follows:

	Net Ownership Interest	Earnings (Losses) from Unconsolidated Affiliates		Earnings (Losses) from Unconsolidated Affiliates	
	June 30,	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	2005	2004	2005	2004
	(Percent)	(In millions)			
Domestic:					
Enterprise Products Partners, L.P.[1]	—	$ —	$ —	$183	$ —
GulfTerra Energy Partners, L.P.[1]	—	—	29	—	63
Citrus	50	18	21	33	28
Midland Cogeneration Venture (MCV)[2]	44	(4)	(2)	(3)	3
Great Lakes Gas Transmission	50	14	16	31	36
Other Domestic Investments	various	4	8	6	9
Total domestic		32	72	250	139
Foreign:					
Asia Investments[3]	various	—	20	(68)	41
Central American Investments[4]	various	(55)	—	(49)	3
PPN[5]	—	—	—	22	—
Other Foreign Investments	various	4	6	16	2
Total foreign		(51)	26	(79)	46
Total earnings from unconsolidated affiliates		$(19)	$ 98	$171	$185

(1) In January 2005, we sold all of these remaining interests to Enterprise and recognized a $183 million gain.

(2) Our proportionate share of MCV's losses, after intercompany eliminations, was $14 million during the second quarter of 2005. We did not record our remaining proportionate share of MCV's losses as these losses resulted primarily from changes in the fair value of their derivative contracts, which we believe did not affect the value of our investment and would not be realized. We did not recognize substantially all of our proportionate share of MCV's earnings, after intercompany eliminations, of approximately $58 million during the six months ended June 30, 2005 for the same reasons.

(3) Consists of our investments in 12 power plants, including Korea Independent Energy Corporation, Meizhou Wan Generating, Habibullah Power and Saba Power Company. Our proportionate share of earnings reported by our Asia investments was $19 million and $44 million, for the quarter and six months ended June 30, 2005. We decreased our proportionate share of equity earnings for our Asia investments by $8 million and $19 million, for the quarter and six months ended June 30, 2005, to reflect the amount of earnings we believe will be realized.

(4) Consists of our investments in 6 power plants. Our proportionate share of earnings reported by our Central American investments was $2 million and $8 million for the quarter and six months ended June 30, 2005. We recorded an impairment of $57 million during the quarter ended June 30, 2005 related to these investments.

(5) We sold our interest in March 2005 and recorded a $22 million gain.

The table below reflects our recognized impairment charges and gains and losses on sales of equity investments that are included in earnings (losses) from unconsolidated affiliates for the periods ended June 30:

Investment	Quarter Ended June 30,	Six Months Ended June 30,
	Pre-tax Gain (Loss) (In millions)	
2005		
Impairments		
Asia power investments[1]	$(11)	$(93)
Central American power investments[1]	(57)	(57)
Other foreign investments[1]	(16)	(17)
Midland Cogeneration Venture[2]	(4)	(4)
Gain on sale of PPN	—	22
Gain on sale of Enterprise	—	183
Other	1	(2)
	$(87)	$ 32
2004		
Impairments		
Milford power facility[1]	$ —	$ (2)
Power plants held for sale[1]	(19)	(35)
Other	1	(5)
	$(18)	$(42)

(1) We impaired our interests in these investments based on information received regarding the potential value we may receive when we sell the investments.

(2) We impaired our investment in this power facility due to delays in the timing of expected cash flow receipts from this investment.

The summarized financial information below includes our proportionate share of the operating results of our unconsolidated affiliates, including affiliates in which we hold a less than 50 percent interest as well as those in which we hold a greater than 50 percent interest for the periods ended June 30:

	Quarter Ended June 30,			Six Months Ended June 30,		
	MCV	Other Investments	Total	MCV	Other Investments	Total
		(In millions)			(In millions)	
2005						
Operating results data						
Revenues	$ 62	$342	$404	$127	$ 625	$ 752
Operating expenses	69	208	277	34	384	418
Income (loss) from continuing operations	(17)	67	50	75	134	209
Net income (loss)[1]	(17)[2]	67	50	75[2]	134	209
2004						
Operating results data						
Revenues	$ 69	$558	$627	$139	$1,072	$1,211
Operating expenses	60	359	419	113	691	804
Income (loss) from continuing operations	(2)	107	105	3	214	217
Net income (loss)[1]	(2)	112	110	3	216	219

[1] Includes net income of $10 million and $7 million for the quarters ended June 30, 2005 and 2004, and $14 million and $21 million for the six months ended June 30, 2005 and 2004, related to our proportionate share of affiliates in which we hold a greater than 50 percent interest.

[2] Includes $3 million of losses during the second quarter of 2005 and $17 million of earnings during the six months ended June 30, 2005 attributable to transactions with El Paso which were eliminated.

We received distributions and dividends from our investments of $64 million and $72 million for each of the quarters ended June 30, 2005 and 2004, and $147 million and $168 million for the six months ended June 30, 2005 and 2004.

Related Party Transactions

We enter into a number of transactions with our unconsolidated affiliates in the ordinary course of conducting our business. The following table shows the income statement impact on transactions with our affiliates for the periods ended June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
		(In millions)		
Operating revenue	$43	$63	$92	$118
Cost of sales	2	38	6	60
Reimbursement for operating expenses	—	34	1	65
Other income	5	4	9	9

GulfTerra Energy Partners, L.P.

Prior to the sale of our interests in GulfTerra to Enterprise in September 30, 2004, our Field Services segment managed GulfTerra's daily operations and performed all of GulfTerra's administrative and operational activities under a general and administrative services agreement or, in some cases, separate operational agreements. GulfTerra contributed to our income through our general partner interest and our ownership of common and preference units. We did not have any loans to or from GulfTerra.

In December 2003, GulfTerra and a wholly owned subsidiary of Enterprise executed definitive agreements to merge and form the second largest publicly traded energy partnership in the United States. On July 29, 2004, GulfTerra's unitholders approved the adoption of its merger agreement with Enterprise which was completed in September 2004. In January 2005, we sold our remaining 9.9 percent interest in the general partner of Enterprise and approximately 13.5 million common units in Enterprise for $425 million, which resulted in a gain of approximately $183 million. We also sold our membership interest in two subsidiaries that own and operate natural gas gathering systems and the Indian Springs processing facility to Enterprise for $75 million, which resulted in a loss of approximately $1 million.

During 2004, our segments conducted transactions in the ordinary course of business with GulfTerra, including operational services and sales of natural gas under transportation contracts, the net financial impact of which are included in revenues. We incurred losses on our transportation contracts with GulfTerra, net of other revenues, of $4 million for the quarter and six months ended June 30, 2004. Expenses paid to GulfTerra were $36 million and $56 million and reimbursements from GulfTerra were $23 million and $45 million for the quarter and six months ended June 30, 2004.

Contingent Matters that Could Impact Our Investments

Economic Conditions in the Dominican Republic. We have investments in power projects in the Dominican Republic with an aggregate exposure of approximately $60 million. We own an approximate 25 percent ownership interest in a 416 MW power generating complex known as Itabo. We also own an approximate 48 percent interest in a 67 MW heavy fuel oil fired power project known as the CEPP project. The country is emerging from an economic crisis that developed in 2003 resulting in a significant devaluation of the Dominican peso. As a result of these economic conditions, combined with the high prices on imported fuels, and due to their inability to pass through these high fuel costs to their consumers, the local distribution companies that purchase the electrical output of these facilities were delinquent in their payments to CEPP and Itabo, and to the other generating facilities in the Dominican Republic. The government of the Dominican Republic has signed an agreement with the IMF and World Bank that restores lending programs and provides for the recovery of the power sector. This led to the government's agreement to keep payments current and address the arrears to the generating companies. In addition, a recent local court decision has resulted in the potential inability of CEPP to continue to receive payments for its power sales, which may affect CEPP's ability to operate. The local court decision has been stayed pending our appeal to the Supreme Court of the Dominican Republic. We continue to monitor the economic and payment situation in the Dominican Republic and as new information becomes available or future material developments arise, it is possible that future impairments of these investments may occur.

Bolivia. We own an eight percent interest in the Bolivia to Brazil pipeline in which we have approximately $96 million of exposure, including guarantees, as of June 30, 2005. During the second quarter of 2005, political disputes in Bolivia related to pressure to nationalize the energy industry led to the resignation of the president of Bolivia. Additionally, recent changes in Bolivian law also increased the combined rate of production taxes and royalties to 50 percent and required that existing exploration contracts be renegotiated. Further deterioration of the political environment in Bolivia could potentially lead to a disruption or cessation of the supply of gas from Bolivia and impact the payments that the Bolivia to Brazil pipeline receives from Petrobras. We continue to monitor the political situation in Bolivia and as new information becomes available or future material developments arise, it is possible that a future impairment of our investment may occur.

Berkshire Power Project. We own a 56 percent direct equity interest in a 261 MW power plant, Berkshire Power, located in Massachusetts. Berkshire's lenders have asserted that Berkshire is in default on its loan agreement (but no remedies have been exercised at this point). We supply natural gas to Berkshire under a fuel management agreement. Berkshire had the ability to delay payment of 33 percent of the amounts due to us under the fuel supply agreement, up to a maximum of $49 million which Berkshire reached in March 2005. We reserved the cumulative amount of the delayed payments based on Berkshire's inability to generate adequate cash flows related to this agreement. We continue to supply fuel to the plant under the fuel supply agreement and we may incur losses if amounts owed on future fuel deliveries are not paid for under this agreement because of Berkshire's inability to generate adequate cash flow and the uncertainty surrounding their negotiations with their lenders.

Brazil. For contingent matters that could impact our investments in Brazil, see Note 10.

Duke Litigation. Citrus Trading Corporation (CTC), a direct subsidiary of Citrus Corp. (Citrus), in which we own a 50 percent equity interest, has filed suit against Duke Energy LNG Sales, Inc. (Duke) and PanEnergy Corp., an affiliate of Duke, seeking damages of $185 million for breach of a gas supply contract and wrongful termination of that contract. Duke sent CTC notice of termination of the gas supply contract alleging failure of CTC to increase the amount of an outstanding letter of credit as collateral for its purchase obligations. Duke has filed in federal court an amended counter claim joining Citrus and a cross motion for partial summary judgment, requesting that the court find that Duke had a right to terminate its gas sales contract with CTC due to the failure of CTC to adjust the amount of the letter of credit supporting its purchase obligations. CTC filed an answer to Duke's motion, which is currently pending before the court. An unfavorable outcome on this matter could impact the value of our investment in Citrus.

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 2004 Annual Report on Form 10-K, as amended, and the financial statements and notes presented in Item 1 of this Quarterly Report on Form 10-Q.

During the second quarter of 2005, we discontinued our south Louisiana gathering and processing operations, which were part of our Field Services segment. Our operating results for the quarter and six months ended June 30, 2005 reflect these operations as discontinued. Prior period amounts have not been adjusted as these operations were not material to prior period results or historical trends.

Overview

Since the beginning of 2005, we have completed the following activities in connection with the ongoing execution of our strategic plan:

- Our Pipeline segment made further progress on its plans by settling a rate case at Southern Natural Gas Company (SNG), recontracting with large customers on the SNG and EPNG systems, and making progress on several pipeline expansion projects in our pipeline systems and at our Elba Island LNG facility;
- Our Production segment continued to make progress on its turnaround and the stabilization of its production rates through its capital program and four strategic acquisitions of natural gas and oil properties totalling approximately $1.1 billion, including our recently announced Medicine Bow acquisition, which we expect to close in the third quarter of 2005 for approximately $814 million;
- We continued the exit of our legacy trading business through the assignment or termination of derivative contracts associated with Cedar Brakes I and II;
- We completed the sale of a number of assets and investments including, among others, our remaining general and limited partnership interests in Enterprise, interests in Cedar Brakes I and II, the Lakeside Technology Center, and our interest in a Korean power facility. Total proceeds from these sales were approximately $1.2 billion ($918 million through June 30, 2005);
- We reduced our net debt to $15.9 billion (debt of $17.48 billion, net of cash of $1.54 billion) as of June 30, 2005, lowering our net debt by $1.1 billion; and
- We completed a private placement of $750 million of 4.99% convertible perpetual preferred stock. The proceeds from this offering were used to prepay our remaining deferred payment obligation on the Western Energy Settlement for $442 million and to redeem the $300 million of EPTP, 8.25%, Series A cumulative preferred stock.

Capital Resources and Liquidity

Our 2004 Annual Report on Form 10-K, as amended, includes a detailed discussion of our liquidity, financing activities, contractual obligations and commercial commitments. The information presented below updates, and you should read it in conjunction with, the information disclosed in that Form 10-K, as amended.

During the six months ended June 30, 2005, we continued to reduce our overall debt as part of our Long Range Plan announced in December 2003. Our activity during the six months ended June 30, 2005 was as follows (in millions):

Short-term financing obligations, including current maturities	$ 955
Long-term financing obligations	18,241
Total debt as of December 31, 2004	19,196
Principal amounts borrowed	466
Repayments/retirements of principal	(1,563)
Sales of entities[1]	(546)
Other reductions	(75)
Total debt as of June 30, 2005	$17,478

[1] Related to the sale of Cedar Brakes I and II.

For a further discussion of our long-term debt and other financing obligations, and other credit facilities, see Item 1, Financial Statements, Note 9.

Our net available liquidity as of June 30, 2005 was $1.7 billion, which consisted of $0.4 billion of availability under our $3 billion credit agreement and $1.3 billion of available cash. The availability of borrowings under our credit agreement and our ability to incur additional debt is subject to various conditions as further described in Item 1, Financial Statements, Note 9 and our 2004 Annual Report on Form 10-K, as amended, Part II, Item 8, Financial Statements and Supplementary Data, Note 15, which we currently meet. These conditions include compliance with financial covenants and ratios requiring our Debt to Consolidated EBITDA not to exceed 6.5 to 1 and our ratio of Consolidated EBITDA to interest expense and dividends to be equal to or greater than 1.6 to 1, each as defined in our $3 billion credit agreement. As of June 30, 2005, our ratio of Debt to Consolidated EBITDA was 4.68 to 1 and our ratio of Consolidated EBITDA to interest expense and dividends was 2.06 to 1.

We believe we will be able to meet our ongoing liquidity and cash needs through the combination of available cash, cash flow from operations and borrowings under our $3 billion credit agreement. However, a number of factors could influence our liquidity sources, as well as the timing and ultimate outcome of our ongoing efforts and plans as further discussed in our 2004 Annual Report on Form 10-K, as amended.

Overview of Cash Flow Activities for 2005 Compared to 2004

For the six months ended June 30, 2005 and 2004, our cash flows are summarized as follows:

	2005	2004
	(In billions)	
Cash Inflows		
Continuing operating activities		
Net loss before discontinued operations	$(0.1)	$(0.1)
Non-cash income adjustments	0.9	0.8
Change in assets and liabilities	(0.8)	(0.6)
	—	0.1
Continuing investing activities		
Net proceeds from the sale of assets and investments	0.8	0.2
Proceeds from settlement of foreign currency derivatives	0.1	—
Reduction of restricted cash	0.1	0.4
Other	0.1	0.1
	1.1	0.7
Continuing financing activities		
Net proceeds from the issuance of long-term debt	0.5	0.1
Proceeds from the issuance of preferred and common stock	0.7	0.1
Contributions from discontinued operations	0.1	0.9
	1.3	1.1
Total cash inflows	$ 2.4	$ 1.9
Cash Outflows		
Continuing investing activities		
Additions to property, plant and equipment	$ 0.8	$ 0.8
Net cash paid for acquisitions	0.2	—
	1.0	0.8
Continuing financing activities		
Payments to retire debt and redeem preferred interests	1.6	1.0
Redemption of preferred stock	0.3	—
Other	0.1	0.1
	2.0	1.1
Total cash outflows	$ 3.0	$ 1.9
Net change in cash	$(0.6)	$ —

Cash From Continuing Operating Activities

Overall, cash inflows from our continuing operating activities for the first six months of 2005 were slightly below cash inflows from continuing operating activities during the same period of 2004. The decrease in operating cash flow in 2005 as compared to 2004 was due primarily to differences in working capital utilization in the two periods. In the first six months of 2005, we experienced a $0.8 billion use of working capital, which included a $0.2 billion payment to assign or terminate derivative contracts in connection with the sale of Cedar Brakes I and II, $0.2 billion of hedging derivative settlements and $0.4 billion for the prepayment of the Western Energy Settlement. In the first six months of 2004, we experienced a $0.6 billion use of working capital primarily due to a payment to settle the principal litigation under the Western Energy Settlement.

Cash From Continuing Investing Activities

Net cash provided by our continuing investing activities was $0.1 billion for the six months ended June 30, 2005. Our investing activities consisted of the following (in billions):

Production exploration, development and acquisition expenditures	$(0.6)
Pipeline expansion, maintenance and integrity projects	(0.3)
Decrease in restricted cash	0.1
Settlement of a foreign currency derivative	0.1
Proceeds from sales of assets and investments	0.8
Total continuing investing activities	$ 0.1

Cash received from sales of assets and investments was primarily from the sale of our remaining interests in Enterprise and the sale of the Lakeside Technology Center. The settlement of a foreign currency derivative relates to cash received on a derivative entered into to hedge currency and interest rate risk on a portion of our Euro denominated debt. This derivative was settled upon the retirement of that debt. In July 2005, we announced that we will acquire Medicine Bow for $0.8 billion. The acquisition will be funded by existing cash on hand and a new $500 million, five-year revolving credit facility which will be collateralized by a portion of EPPH's existing natural gas and oil reserves. We intend to repay this facility within one year from closing through an issuance of equity. We also expect additional capital expenditures of $0.3 billion in our Production segment and $0.7 billion in our Pipelines segment during the remainder of 2005.

Cash From Continuing Financing Activities

Net cash used in our continuing financing activities was $0.7 billion for the six months ended June 30, 2005. We generated cash of $1.2 billion from the issuance of $0.7 billion of convertible preferred stock, and $0.5 billion of long-term debt on CIG and Cheyenne Plains. However, we made repayments of $0.9 billion to retire third party long-term debt, paid $0.7 billion to retire a portion of our Euro-denominated debt and redeemed $0.3 billion of cumulative preferred stock of EPTP, our subsidiary.

Commodity-based Derivative Contracts

We use derivative financial instruments in our hedging activities, power contract restructuring activities and in our historical energy trading activities. The following table details the fair value of our commodity-based derivative contracts by year of maturity as of June 30, 2005:

Source of Fair Value	Maturity Less Than 1 year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity 6 to 10 Years	Maturity Beyond 10 Years	Total Fair Value
			(In millions)			
Derivatives designated as hedges						
Assets	$ 16	$ 9	$ —	$ —	$ —	$ 25
Liabilities	(423)	(196)	(27)	(19)	—	(665)
Total derivatives designated as hedges	(407)	(187)	(27)	(19)	—	(640)
Assets from power contract restructuring derivatives[1]	20	40	—	—	—	60
Other commodity-based derivatives						
Exchange-traded positions[2]						
Assets	115	243	135	13	—	506
Liabilities	(102)	(9)	(1)	—	—	(112)
Non-exchange-traded positions						
Assets	421	379	197	151	27	1,175
Liabilities[1]	(394)	(591)	(312)	(186)	(50)	(1,533)
Total other commodity-based derivatives	40	22	19	(22)	(23)	36
Total commodity-based derivatives	$(347)	$(125)	$ (8)	$ (41)	$(23)	$ (544)

(1) Includes $6 million of intercompany derivatives that eliminate in consolidation and had no impact on our consolidated assets and liabilities from price risk management activities for the six months ended June 30, 2005.

(2) Exchange-traded positions are those traded on active exchanges such as the New York Mercantile Exchange, the International Petroleum Exchange and the London Clearinghouse.

Below is a reconciliation of our commodity-based derivatives for the period from January 1, 2005 to June 30, 2005:

	Derivatives Designated as Hedges[1]	Derivatives from Power Contract Restructuring Activities	Other Commodity-Based Derivatives	Total Commodity-Based Derivatives
		(In millions)		
Fair value of contracts outstanding at January 1, 2005	$(536)	$ 665	$ (61)	$ 68
Fair value of contract settlements during the period	182	(616)	282	(152)
Change in fair value of contracts	(286)	11	(182)	(457)
Option premiums received, net	—	—	(3)	(3)
Net change in contracts outstanding during the period	(104)	(605)	97	(612)
Fair value of contracts outstanding at June 30, 2005	$(640)	$ 60	$ 36	$(544)

(1) In December 2004, we designated a number of our other commodity-based derivative contracts in our Marketing and Trading segment as hedges of our 2005 and 2006 natural gas production. As a result, we reclassified this $592 million liability to derivatives designated as hedges in December 2004.

The fair value of contract settlements during the period represents the estimated amounts of derivative contracts settled through physical delivery of a commodity or by a claim to cash as accounts receivable or payable. The fair value of contract settlements also includes physical or financial contract terminations due to counterparty bankruptcies and the sale or settlement of derivative contracts through early termination or through the sale of the entities that own these contracts.

In March 2005, we sold our Cedar Brakes I and II subsidiaries and their related restructured power contracts, which had a fair value of $596 million as of December 31, 2004. In connection with the sale, we also assigned or terminated other commodity-based derivatives that had a fair value liability of $240 million as of December 31, 2004.

The change in fair value of contracts during the period represents the change in value of contracts from the beginning of the period, or the date of their origination or acquisition, until their settlement or, if not settled, until the end of the period.

Segment Results

Below are our results of operations (as measured by EBIT) by segment. Our regulated business consists of our Pipelines segment, while our unregulated businesses consist of our Production, Marketing and Trading, Power and Field Services segments. Our segments are strategic business units that provide a variety of energy products and services. They are managed separately as each segment requires different technology and marketing strategies. Our corporate activities include our general and administrative functions, as well as a telecommunications business and various other contracts and assets. During the second quarter of 2005, we discontinued our south Louisiana gathering and processing operations, which were part of our Field Services segment. Our operating results for the quarter and six months ended June 30, 2005 reflect these operations as discontinued. Prior period amounts have not been adjusted as these operations were not material to prior period results or historical trends.

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. Our business operations consist of both consolidated businesses as well as investments in unconsolidated affiliates. We believe EBIT is useful to our investors because it allows them to more effectively evaluate the performance of all of our businesses and investments. Also, 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. EBIT may not be comparable to measures used by other companies. Additionally, EBIT should be considered in conjunction with net income and other performance measures such as operating income or operating cash flow. Below is a reconciliation of our consolidated EBIT to our consolidated net income (loss) for the periods ended June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
	(In millions)			
Regulated Business				
Pipelines	$ 309	$ 308	$ 721	$ 694
Non-regulated Businesses				
Production	176	204	359	408
Marketing and Trading	(30)	(152)	(215)	(316)
Power	(381)	102	(431)	(67)
Field Services	(3)	27	179	63
Segment EBIT	71	489	613	782
Corporate	(12)	9	(102)	36
Consolidated EBIT from continuing operations	59	498	511	818
Interest and debt expense	(340)	(410)	(690)	(833)
Distributions on preferred interests of consolidated subsidiaries	(3)	(6)	(9)	(12)
Income taxes	51	(48)	57	(58)
Income (loss) from continuing operations	(233)	34	(131)	(85)
Discontinued operations, net of income taxes	(5)	(29)	(1)	(106)
Net income (loss)	$(238)	$ 5	$(132)	$(191)

Overview of Segment Results

For the six months ended June 30, 2005, our segment EBIT was $613 million. During the six month period, our Pipelines, Production and Field Services segments contributed $1,259 million of combined EBIT. These positive contributions were partially offset by the EBIT losses of $215 million in our Marketing and Trading segment and $431 million in our Power segment. The following overview summarizes the results of operations by operating segment compared to our internal expectations for the period.

Pipelines — Our Pipelines segment generated EBIT of $721 million, which was slightly above our expectations for the period.

Production — Our Production segment generated EBIT of $359 million, which was slightly above our expectations for the period. Lower than expected production volumes and higher depreciation and production costs were more than offset by higher than expected commodity prices.

Marketing and Trading — Our Marketing and Trading segment generated an EBIT loss of $215 million, which was a greater loss than our expectations. The performance was driven by significant mark-to-market losses on our production-related derivatives due to natural gas price increases during the period. In addition, our power contracts, primarily our Cordova tolling agreement, experienced significant losses during the period due to changes in natural gas and power prices.

Power — Our Power segment generated an EBIT loss of $431 million, which was a greater loss than expected and was impacted by significant impairments of our Macae project in Brazil and impairments of our Asian and Central American power assets based on additional information received about the value we may receive upon the sale of these assets.

Field Services — Our Field Services segment generated EBIT of $179 million, which was consistent with our expectations and was primarily due to the gain on the sale of our remaining interests in Enterprise.

For the remainder of 2005, we expect the trends discussed above to continue in our Pipeline and Production segments, given the historic stability in our pipeline business and the current favorable pricing environment for natural gas and oil. We also anticipate our Marketing and Trading segment's EBIT will continue to be volatile due to changes in natural gas and power prices as they relate to our trading portfolio. In our Power segment, we may generate EBIT losses as we continue to sell or pursue the sale of our Asian and Central American power plant portfolio and continue negotiations with Petrobras relating to our Macae power investment. Finally, we expect our EBIT to decline in our Field Services segment as a result of the completion of sales of substantially all of our remaining gathering and processing assets. Below is a discussion of our individual segment results.

Regulated Business — Pipelines Segment

Operating Results

Below are the operating results and analysis of these results for our Pipelines segment for the periods ended June 30:

Pipelines Segment Results	Quarter Ended June 30, 2005	Quarter Ended June 30, 2004	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
	(In millions except volume amounts)			
Operating revenues	$ 653	$ 617	$ 1,421	$ 1,338
Operating expenses	(391)	(357)	(797)	(730)
Operating income	262	260	624	608
Other income	47	48	97	86
EBIT	$ 309	$ 308	$ 721	$ 694
Throughput volumes (BBtu/d)	20,316	19,935	21,444	21,223

The following contributed to our overall EBIT increase of $1 million and $27 million for the quarter and six months ended June 30, 2005 as compared to the same periods in 2004:

	Quarter Ended June 30,				Six Months Ended June 30,			
	Revenue	Expense	Other	EBIT	Revenue	Expense	Other	EBIT
	Favorable/(Unfavorable) (In millions)				Favorable/(Unfavorable) (In millions)			
Contract modifications/terminations/settlements	$14	$ —	$ 1	$ 15	$ 46	$ —	$ 1	$ 47
Gas not used in operations, processing revenues and other natural gas sales	(1)	10	—	9	19	1	—	20
Favorable resolution in 2004 of measurement dispute at a processing plant	—	—	—	—	(10)	—	—	(10)
Pipeline expansions	22	(8)	2	16	38	(15)	2	25
Higher allocated costs	—	(25)	—	(25)	—	(46)	—	(46)
Equity earnings from our investment in Citrus	—	—	(3)	(3)	—	—	5	5
Other(1)	1	(11)	(1)	(11)	(10)	(7)	3	(14)
Total impact on EBIT	$36	$(34)	$(1)	$ 1	$ 83	$(67)	$11	$ 27

(1) Consists of individually insignificant items across several of our pipeline systems.

The following provides further discussion on the items listed above as well as an outlook on events that may affect our operations in the future.

Contract Modifications/Terminations/Settlements. Included in this item are (i) the impact of ANR completing the restructuring of its transportation contracts with one of its shippers on its Southwest and Southeast Legs as well as a related gathering contract in March 2005, which increased revenues and EBIT by $29 million in the first quarter of 2005 (ii) the impact of ANR's settlement in the second quarter of 2005 of two transportation agreements previously rejected in the bankruptcy of USGen New England, Inc., which increased EBIT by $15 million and (iii) the impact of the termination, in April 2004, of EPNG's restrictions on remarketing expiring capacity contracts resulting in increased revenues and EBIT of $5 million during the first six months of 2005 as compared to 2004. ANR's settlement with USGen will not have an ongoing impact on our Pipelines segment results.

SoCal successfully acquired approximately 750 MMcf/d of capacity on EPNG's system under new contracts with various terms extending from 2009 to 2011 commencing September 2006. We are in the process of consummating the transaction entered into in December 2004 by executing the relevant transportation service agreements with SoCal. Effective September 2006, approximately 500 MMcf/d of capacity formerly held by SoCal to serve its non-core customers will be available for recontracting. We are continuing in our efforts to remarket the remaining expiring capacity to serve SoCal's non-core customers or to serve new markets. We are also pursuing the option of using some or all of this capacity to provide new services to existing markets. At this time, we are uncertain how much of this remaining capacity formerly held by SoCal will be recontracted, and if so at what rates.

Gas Not Used in Operations, Processing Revenues and Other Natural Gas Sales. For some of our regulated pipelines, the financial impact of operational gas, net of gas used in operations is based on the amount of natural gas we are allowed to recover and dispose of according to our tariffs or FERC orders, relative to the amount of gas we use for operating purposes, and the price of natural gas. Gas not needed for operations results in revenues to us, which are driven by volumes and prices during a given period. These recoveries of gas on our systems relative to amounts we use are based on factors such as system throughput, facility enhancements and the ability to operate the systems in the most efficient and safe manner. In 2005, the sale of higher volumes of natural gas made available by storage realignment projects was partially offset by higher volumes of gas utilized in operations, resulting in an overall favorable impact on our operating results in 2005 versus 2004. We anticipate that this overall activity will continue to vary in the future and will be impacted by things such as rate actions, some of which have already been implemented, the efficiency of our pipeline operations, natural gas prices and other factors. For a further discussion of this area of our business, refer to our 2004 Annual Report on Form 10-K, as amended.

Expansions. In June 2005, SNG filed with the FERC for permission to construct a 176 mile expansion of its system which will provide 500,000 Mcf/d of firm transportation to be phased in over four years beginning in May 2007. Total cost estimates for the project are approximately $321 million and construction is expected to begin upon FERC approval in 2006. This expansion is currently expected to increase our revenues by an estimated $62 million annually.

As of January 31, 2005, our Cheyenne Plains pipeline was placed in-service. As a result, revenues increased by $28 million and overall EBIT increased by $13 million during the first six months of 2005 compared to the same period in 2004.

In April 2003, the FERC approved the expansion of the Elba Island LNG facility to increase the base load sendout rate of the facility from 446 MMcf/d to 806 MMcf/d. Our current cost estimates for the expansion are approximately $157 million and as of June 30, 2005, our expenditures were approximately $118 million. We commenced construction in July 2003 and expect to place the expansion in service in February 2006. As a result of increasing levels of capital invested in the expansion, higher AFUDC in 2005 resulted in higher EBIT compared to 2004. This expansion is currently expected to increase our revenues by an estimated $29 million annually.

In June 2005, the FERC issued a certificate authorizing CIG to construct the Raton Basin expansion, which will add 104 MMcf/d of capacity to its system. The project is fully subscribed for 10 years, of which 14 percent is held by an affiliate. Construction began in June and the project is expected to be in service by October 2005. This expansion is currently expected to increase revenues by an estimated $9 million in 2006 and an estimated $13 million annually thereafter.

In order to meet increased demand in EPNG's markets and comply with FERC orders, EPNG completed Phases I, II and III of its Line 2000 Power-up project in 2004, which increased the capacity of that line by 320 MMcf/d. In addition, in June 2005, EPNG received FERC certificate approval for the EPNG

Cadiz to Ehrenberg project that will increase its north-to-south capacity by 372 MMcf/d. The project is scheduled to be in service by late 2005. Construction and conversion will begin as soon as we receive approval from the California State Land Commission and the U.S. Department of the Interior's Bureau of Land Management. EPNG expects to earn revenues associated with these expansions beginning in January 2006, the effective date of its recent rate filing.

Allocated Costs. We allocate general and administrative costs to each business segment. The allocation is based on the estimated level of effort devoted to each segment's operations and the relative size of its EBIT, gross property and payroll as compared to our consolidated totals. During the quarter and six months ended June 30, 2005, the Pipelines segment was allocated higher costs than the same periods in 2004, primarily due to an increase in our benefits accrued under our retirement plan and higher legal, insurance and professional fees. In addition, we were allocated a larger percentage of El Paso's total corporate costs due to the significance of our asset base and earnings to the overall El Paso asset base and earnings.

Accounting for Pipeline Integrity Costs. In June 2005, the FERC issued an accounting release that will impact certain costs our interstate pipelines incur related to their pipeline integrity programs. This release will require us to expense certain pipeline integrity costs incurred after January 1, 2006 instead of capitalizing them as part of our property, plant and equipment. Although we continue to evaluate the impact that this accounting release will have on our consolidated financial statements, we currently estimate that we would be required to expense an additional amount of pipeline integrity costs under the release in the range of approximately $23 million to $39 million annually.

Regulatory and Other Matters

Our pipeline systems periodically file for changes in their rates which are subject to the approval of the FERC. Changes in rates and other tariff provisions resulting from these regulatory proceedings have the potential to negatively impact our profitability.

EPNG Rate Case. In June 2005, EPNG filed a rate case with the FERC proposing an increase in revenues of 10.6 percent or $56 million over current tariff rates, subject to refund, and also proposing new services and revisions to certain terms and conditions of existing services, including the adoption of a fuel tracking mechanism. The rate case would be effective January 1, 2006. In addition, the reduced tariff rates provided to EPNG's former full requirements (FR) customers under the terms of its FERC approved systemwide capacity allocation proceeding will expire on January 1, 2006. The combined effect of the proposed increase in tariff rates and the expiration of the lower rates to EPNG's FR customers are estimated to increase our revenues by approximately $138 million. In July 2005, the FERC accepted certain of the proposed tariff revisions, including the adoption of a fuel tracking mechanism and set the rate case for hearing and technical conference. The FERC directed the scheduling of the technical conference within 150 days of the order and delayed setting a date for the hearing pending resolution of the various matters identified for consideration at the technical conference. We anticipate continued discussions with intervening parties in an attempt to settle the matter and are uncertain of the settlement of this rate case.

The FERC has initially rejected a request made by EPNG in the rate case filed on June 25, 2005 for a tracking mechanism that would have provided an assurance of recovery of the cost of a right-of-way across Navajo Nation land. However, the FERC did invite EPNG to seek a waiver of FERC regulations to permit the cost of the right-of-way to be included in its pending rate case if the final cost becomes known and measurable within a reasonable time after the close of the test period on December 31, 2005. The timing and/or extent of recovery could impact our future financial results.

SNG Rate Case and Other Matter. In August 2004, SNG filed a rate case with the FERC seeking an annual rate increase of $35 million, or 11 percent in jurisdictional rates and certain revisions to its effective tariff regarding terms and conditions of service. In April 2005, SNG reached a tentative settlement in principle that would resolve all issues in our rate proceeding, and filed the negotiated offer of settlement with the FERC on April 29, 2005. SNG implemented the settlement rates on an interim basis as of March 1, 2005 as negotiated rates with all shippers which elected to be consenting parties under the rate settlement. In an order issued in July 2005, the FERC approved the settlement. Under the terms of the settlement, SNG reduced the proposed increase in its base tariff rates by approximately $21 million; reduced its fuel retention percentage and agreed to an incentive sharing mechanism to encourage additional fuel savings; received approval for a capital maintenance tracker that will allow it to recover costs through its rates; adjusted the rates for its South Georgia facilities and agreed to file its next general rate case no earlier than March 1, 2009 and no later than March 31, 2010. The settlement also provided for changes regarding SNG's terms and conditions of service. We do not expect the settlement to have a material impact on its future financial results. In addition, as a result of the contract extensions required by the settlement, the contract terms for firm service now average approximately seven years.

A majority of SNG contracts for firm transportation service with its largest customer, Atlanta Gas Light Company (AGL), were due to expire in 2005. In April 2004, SNG and AGL executed definitive agreements pursuant to which AGL agreed to extend its firm transportation service contracts with SNG for 926,534 Mcf/d for a weighted average term of 6.5 years between 2008 and 2015. In connection with this agreement, SNG sold to AGL approximately 250 miles of certain pipeline facilities and nine measurement facilities in the metropolitan Atlanta area for a transfer price of approximately $32 million. In late 2004 and early 2005 the FERC and the Georgia Public Service Commission (GPSC) approved these transactions. In March 2005, the transaction was closed and SNG recorded a gain of $7 million from the sale of these facilities.

For a further discussion of our current and upcoming rate proceedings, refer to our 2004 Annual Report on Form 10-K, as amended.

Non-regulated Business — Production Segment

Overview

Our Production segment conducts our natural gas and oil exploration and production activities. Our operating results in this segment are driven by a variety of factors including the ability to acquire or locate and develop economic natural gas and oil reserves, extract those reserves with minimal production costs, sell the products at attractive prices, and to minimize our total administrative costs. We continue to manage our business with a goal to stabilize production by improving the production mix across our operating areas through a more balanced allocation of our capital to development and exploration projects, and through acquisition activities with low risk development opportunities that provide operating synergies with our existing operations.

Significant Operational Factors Since December 31, 2004

Since December 31, 2004, we have experienced the following:

- *Higher realized prices.* During the first six months of 2005, we continued to benefit from a strong commodity pricing environment. Realized natural gas prices, which include the impact of our hedges, increased eight percent while oil, condensate and NGL prices increased 33 percent compared to 2004.
- *Average daily production of 775 MMcfe/d (excluding discontinued operations of 3 MMcfe/d).* Our average daily production in the second quarter of 2005 increased approximately two percent over the first quarter of 2005 and was relatively stable compared with the third and fourth quarters of 2004. Specifically, during the last twelve months we have experienced increased production in our onshore region, relatively stable production in our offshore Gulf of Mexico region, and declining production in our Texas Gulf Coast region due to normal declines and mechanical well failures. In addition, we acquired the remaining interest in UnoPaso located in Brazil in July 2004 and began consolidating this operation. During the first six months of 2005, our operations in Brazil produced at an average of approximately 54 MMcfe/d, and our first quarter 2005 acquisitions of domestic producing properties discussed below benefited our average daily production by approximately 44 MMcfe/d. In July 2005, hurricanes in the Gulf of Mexico caused us to shut in production for periods of time impacting production volumes by approximately 12 MMcfe/d for the month.

- *Acquisitions and other capital expenditures.* During the first six months of 2005, our capital expenditures of $651 million included acquisitions in east and south Texas and the purchase of the interest held by one of our partners under a net profits interest agreement for a total of $271 million. These acquisitions added properties with approximately 140 Bcfe of proved reserves and 52 MMcfe/d of production at the acquisition dates. More importantly, the Texas acquisitions offer additional exploration upside in two of our key operating areas. We have integrated these acquisitions into our operations with minimal additional administrative expenses.

  In July 2005, we announced we will acquire Medicine Bow, a privately held energy company with an estimated 356 Bcfe of proved reserves, primarily in the Rocky Mountains and east Texas, for $814 million. Of this proved reserve amount, our net interest of approximately 226 Bcfe will not be consolidated in our reserves, as these reserves are owned by an unconsolidated affiliate of Medicine Bow. The operating results associated with these unconsolidated reserves will be reported through an equity interest. Concurrent with this announcement, our Marketing and Trading segment entered into several derivative positions associated with the properties to be acquired as further discussed on page 52. The acquisition of these properties will complement our existing core operations, diversify our commodity mix and increase our reserve life. The transaction is expected to close during the third quarter of 2005.

- *Drilling Results.* In 2005, we have announced deep shelf discoveries at West Cameron Block 75 and West Cameron Block 62 in the Gulf of Mexico. At West Cameron Block 75, we tested the discovery and anticipate deliverability of approximately 40 MMcfe/d to begin in the fourth quarter of 2005, after the installation of facilities. We own a 36 percent working interest and an approximate 30 percent net revenue interest in the West Cameron Block 75.

Outlook for the last six months of 2005

For 2005, we anticipate the following:

- Total capital expenditures of approximately $1.1 billion for the last six months of 2005, including amounts to be paid to acquire Medicine Bow.

- Daily production volumes for the year to average in excess of 810 MMcfe/d, including approximately 10 MMcfe/d expected from the Medicine Bow acquisition and 24 MMcfe/d from Medicine Bow's interest in an unconsolidated affiliate.

- Cash operating costs to be approximately $1.45/Mcfe as we continue to focus on cost control, operating efficiencies, and process improvements.

- Industry-wide increases in drilling and oilfield service costs that will require constant monitoring of capital spending programs.

- A domestic unit of production depletion rate of $2.10/Mcfe in the third quarter of 2005 as compared to $2.04/Mcfe in the second quarter of 2005, due to higher finding and development costs and the costs of acquired reserves. We also expect our depletion rate to increase further in the fourth quarter of 2005 as we complete the announced Medicine Bow acquisition.

Production Hedge Position

As part of our overall strategy, we hedge our natural gas and oil production to stabilize cash flows, reduce the risk of downward commodity price movements on our sales and to protect the economic assumptions associated with our capital investment and acquisition programs. Our Marketing and Trading segment has also entered into other derivative contracts that are designed to provide price protection to the overall company, which are discussed further in that segment's operating results. Our hedging activities are further discussed in our 2004 Annual Report on Form-10-K, as amended.

Overall, we experienced a significant decrease in the fair value of our hedging derivatives in the first six months of 2005. These non-cash fair value decreases are generally deferred in our accumulated other comprehensive income and will be realized in our operating results at the time the production volumes to which they relate are sold. As of June 30, 2005, the fair value of these positions that is deferred in accumulated other comprehensive income was a pre-tax loss of $281 million. The income impact of the settlement of these derivatives will be substantially offset by the impact of the corresponding change in the price to be received when the hedged production is sold.

Operating Results

Below are the operating results and analysis of these results for the periods ended June 30:

Production Segment Results	Quarter Ended June 30, 2005	Quarter Ended June 30, 2004	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004
	(In millions)			
Operating Revenues:				
Natural gas	$ 354	$ 363	$ 707	$ 731
Oil, condensate and NGL	96	66	181	143
Other	2	1	3	2
Total operating revenues	452	430	891	876
Transportation and net product costs[1]	(12)	(13)	(25)	(27)
Total operating margin	440	417	866	849
Operating Expenses:				
Depreciation, depletion and amortization	(157)	(131)	(303)	(271)
Production costs[2]	(59)	(44)	(114)	(86)
Restructuring charges	(2)	(2)	(2)	(11)
General and administrative expenses	(43)	(37)	(84)	(73)
Taxes other than production and income	(4)	(1)	(8)	(3)
Total operating expenses[1]	(265)	(215)	(511)	(444)
Operating income	175	202	355	405
Other income	1	2	4	3
EBIT	$ 176	$ 204	$ 359	$ 408

	Quarter Ended June 30, 2005	Quarter Ended June 30, 2004	Quarter Percent Variance	Six Months Ended June 30, 2005	Six Months Ended June 30, 2004	Six Months Percent Variance
Volumes, prices and costs:						
Natural gas						
Volumes (MMcf)	57,790	61,535	(6)%	113,948	127,234	(10)%
Average realized prices including hedges ($/Mcf)[3][4]	$ 6.13	$ 5.90	4%	$ 6.20	$ 5.75	8%
Average realized prices excluding hedges ($/Mcf)[3]	$ 6.35	$ 5.95	7%	$ 6.03	$ 5.81	4%
Average transportation costs ($/Mcf)	$ 0.17	$ 0.14	21%	$ 0.17	$ 0.15	13%
Oil, condensate and NGL						
Volumes (MBbls)	2,260	1,937	17%	4,396	4,647	(5)%
Average realized prices including hedges ($/Bbl)[3]	$ 42.39	$ 34.11	24%	$ 41.16	$ 30.86	33%
Average realized prices excluding hedges ($/Bbl)[3]	$ 43.07	$ 34.11	26%	$ 41.68	$ 30.86	35%
Average transportation costs ($/Bbl)	$ 0.59	$ 1.54	(62)%	$ 0.67	$ 1.35	(50)%
Total equivalent volumes (MMcfe)	71,351	73,157	(2)%	140,327	155,115	(10)%
Production costs ($/Mcfe)						
Average lease operating cost	$ 0.76	$ 0.51	49%	$ 0.69	$ 0.50	38%
Average production taxes	0.07	0.09	(22)%	0.13	0.06	117%
Total production cost[2]	$ 0.83	$ 0.60	38%	$ 0.82	$ 0.56	46%
Average general and administrative cost ($/Mcfe)	$ 0.61	$ 0.51	20%	$ 0.60	$ 0.47	28%
Unit of production depletion cost ($/Mcfe)	$ 2.05	$ 1.64	25%	$ 2.02	$ 1.61	25%

(1) Transportation and net product costs are included in operating expenses on our consolidated statements of income.

(2) Production costs include lease operating costs and production related taxes (including ad valorem and severance taxes).

(3) Prices are stated before transportation costs

(4) The average realized prices for natural gas, including hedges listed above, reflect the amounts recorded by the Production segment for sales of natural gas volumes. On a consolidated basis, El Paso receives a lower cash price on a portion of the volumes sold as further discussed in our 2004 Annual Report on Form 10-K, as amended.

Quarter and Six Months Ended June 30, 2005 Compared to Quarter and Six Months Ended June 30, 2004

Our EBIT for the quarter and six months ended June 30, 2005 decreased $28 million and $49 million as compared to the quarter and six months ended June 30, 2004. The table below lists the significant variances in our operating results in the quarter and six months ended June 30, 2005 as compared to the same periods in 2004:

Quarter Ended June 30,	Operating Revenue	Operating Expense	Other[(1)]	EBIT Impact
	Variance Favorable/(Unfavorable) (In millions)			
Natural Gas Revenue				
Higher realized prices in 2005	$ 23	$ —	$ —	$ 23
Lower volumes in 2005	(22)	—	—	(22)
Impact from hedge program in 2005 versus 2004	(10)	—	—	(10)
Oil, Condensate, and NGL Revenue				
Higher realized prices in 2005	20	—	—	20
Higher volumes in 2005	11	—	—	11
Impact from hedge program in 2005 versus 2004	(1)	—	—	(1)
Depreciation, Depletion, and Amortization Expense				
Higher depletion rate in 2005	—	(29)	—	(29)
Lower production volumes in 2005	—	3	—	3
Production Costs				
Higher lease operating costs in 2005	—	(17)	—	(17)
Lower production taxes in 2005	—	2	—	2
Other				
Higher general and administrative costs in 2005	—	(6)	—	(6)
Other	1	(3)	—	(2)
Total variances	$ 22	$(50)	$ —	$(28)

Six Months Ended June 30,	Operating Revenue	Operating Expense	Other[(1)]	EBIT Impact
	Variance Favorable/(Unfavorable) (In millions)			
Natural Gas Revenue				
Higher realized prices in 2005	$ 25	$ —	$ —	$ 25
Lower volumes in 2005	(77)	—	—	(77)
Impact from hedge program in 2005 versus 2004	28	—	—	28
Oil, Condensate, and NGL Revenue				
Higher realized prices in 2005	48	—	—	48
Lower volumes in 2005	(8)	—	—	(8)
Impact from hedge program in 2005 versus 2004	(2)	—	—	(2)
Depreciation, Depletion, and Amortization Expense				
Higher depletion rate in 2005	—	(58)	—	(58)
Lower production volumes in 2005	—	24	—	24
Production Costs				
Higher lease operating costs in 2005	—	(19)	—	(19)
Higher production taxes in 2005	—	(9)	—	(9)
Other				
Higher general and administrative costs in 2005	—	(11)	—	(11)
Other	1	6	3	10
Total variances	$ 15	$(67)	$ 3	$(49)

(1) Consists primarily of changes in transportation costs and other income.

Operating Revenues. During 2005, we continued to benefit from a strong commodity pricing environment for natural gas and oil, condensate and NGL. Our hedging program contributed (losses) gains of ($14) million and $17 million for the quarter and six months ended June 30, 2005, compared to ($3) million and ($9) million for the same periods in 2004. Substantially offsetting the impact of the strong commodity pricing environment was a decrease in production volumes versus the same periods in 2004. Although our natural gas and oil production benefited from our east and south Texas acquisitions, our acquisition and consolidation of the remaining interests in UnoPaso in Brazil in July 2004 and increased production in our onshore region, both the Texas Gulf Coast and the offshore regions experienced significant decreases in production due to normal production declines and a lower capital spending program over the last several years. In addition, the Texas Gulf Coast Region was impacted by mechanical well failures.

Depreciation, depletion, and amortization expense. Lower production volumes in 2005 due to the production declines discussed above reduced our depreciation, depletion, and amortization expense. However, more than offsetting this decrease were higher depletion rates due to higher finding and development costs and the cost of acquired reserves.

Production costs. In 2005, we experienced additional costs, including workover costs, as a result of our July 2004 acquisition of UnoPaso located in Brazil, higher domestic workover costs due to the implementation of programs to improve production in the offshore Gulf of Mexico and Texas Gulf Coast regions, higher salt water disposal expenses and higher utility expenses. In addition, our production taxes increased as the result of higher commodity prices in 2005 and higher tax credits taken in 2004 on high cost natural gas wells. The cost per unit increased primarily due to the lower production volumes mentioned above and higher production costs mentioned above.

Other. General and administrative costs are allocated to each business segment. The allocation is based on the estimated level of effort devoted to each segment's operations and the relative size of its EBIT, gross property and payroll as compared to the consolidated totals. During the quarter and six months ended June 30, 2005, the Production segment was allocated higher costs than the same periods in 2004, primarily due to an increase in benefits accrued under retirement plans and higher legal, insurance and professional fees. In addition, the Production segment was allocated a larger percentage of our total corporate costs due to the significance of its asset base and earnings to our overall asset base and earnings. In addition, capitalized overhead costs were lower in 2005 when compared to the same periods in 2004. The cost per unit of general and administrative expenses increased due to a combination of higher costs and lower production volumes discussed above. The decrease in other operating expenses for the six months periods related to employee severance expenses of $2 million in 2005 compared with $11 million in 2004.

Non-regulated Business — Marketing and Trading Segment

Our Marketing and Trading segment's operations focus on the marketing of our natural gas production and the management of our remaining trading portfolio. Our Marketing and Trading segment's portfolio includes both contracts with third parties and contracts with affiliates that require physical delivery of a commodity or financial settlement. We continue to consider opportunities to assign, terminate or otherwise accelerate the liquidation of certain of our legacy trading positions which may result in future losses. For a further discussion of the business activities and portfolio composition of our Marketing and Trading segment, see our 2004 Annual Report on Form 10-K, as amended.

Significant factors impacting or occurring in the six months ended June 30, 2005:

- Increases in natural gas prices continue to have an overall negative impact on the fair value of our natural gas and power derivatives, which generally require us to supply natural gas and power at fixed prices. In addition, natural gas prices increased more than power prices, which negatively impacted the fair value of our Cordova tolling agreement.
- Effective April 1, 2005 we began using new forward pricing data provided by Platts Research and Consulting, our independent pricing source, due to their decision to discontinue the publication of the pricing data we had been utilizing in prior periods. In addition, due to the nature of the new forward

pricing data, we extended the use of that data over the entire contractual term of our derivative contracts. Previously we only used Platts' pricing data to value our derivative contracts beyond two years. Based on our analysis, we do not believe the overall impact of this change in estimate was material to our results for the period.

Operating Results

Below are the overall operating results and analysis of these results for our Marketing and Trading segment for the periods ended June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
	(In millions)			
Overall EBIT:				
Gross margin[1]	$ (21)	$(141)	$(196)	$(300)
Operating expenses	(11)	(13)	(22)	(29)
Operating loss	(32)	(154)	(218)	(329)
Other income	2	2	3	13
EBIT	$ (30)	$(152)	$(215)	$(316)
Gross margin by significant contract type:				
Natural gas contracts				
Production-related and other natural gas derivatives				
Changes in fair value on positions designated as hedges in December 2004	$ —	$(104)	$ —	$(260)
Changes in fair value on production-related contracts	(12)	—	(118)	—
Changes in fair value on other natural gas positions	93	13	119	8
Total production-related and other natural gas derivatives	81	(91)	1	(252)
Transportation-related contracts				
Demand charges	(40)	(40)	(79)	(79)
Settlements	21	26	48	47
Total transportation-related contracts	(19)	(14)	(31)	(32)
Total gross margin — natural gas contracts	62	(105)	(30)	(284)
Power contracts				
Changes in fair value on Cordova tolling agreement	(78)	(18)	(111)	(3)
Changes in fair value on other power derivatives	(22)	(18)	(72)	(13)
Favorable resolution of bankruptcy claim	17	—	17	—
Total gross margin — power contracts	(83)	(36)	(166)	(16)
Total gross margin	$ (21)	$(141)	$(196)	$(300)

(1) Gross margin for our Marketing and Trading segment consists of revenues from commodity trading and origination activities less the costs of commodities sold, including changes in the fair value of our derivative contracts.

Listed below is a discussion of factors, by significant contract type, that affected the profitability of this segment during the quarters and six months ended June 30, 2005 and 2004:

Natural Gas Contracts

Production-related and other natural gas derivatives

- *Derivatives designated as hedges.* The amounts in the above table represent changes in the fair values of derivative contracts that were designated as accounting hedges of our Production segment's natural gas production on December 1, 2004. Losses for the quarter and six months ended June 30, 2004 were a result of increases in natural gas prices relative to the fixed prices in these contracts. Following the designation of these derivatives as accounting hedges in the fourth quarter of 2004, we began reflecting the income impacts of these contracts in our Production segment.
- *Other production-related derivatives.* We hold several option contracts that provide price protection on a portion of our Production segment's anticipated natural gas and oil production. These contracts, which are not accounting hedges and are marked to market in our results each period, provide El Paso with the following floor and ceiling prices on our future natural gas and oil production:

	2005	2006	2007
Natural Gas Options Held at June 30, 2005			
Volumes with Floor Price (TBtu)	36	120	30
Floor Price (per MMBtu)	$6.00	$7.00[1]	$6.00
Volumes with Ceiling Price (TBtu)	—	60	—
Ceiling Price (per MMBtu)	—	$9.50	—
	2007	**2008**	**2009**
Positions Added in July 2005[2]			
Natural Gas Options			
Volumes (TBtu)	21	18	17
Floor Price (per MMBtu)	$7.00	$6.00	$6.00
Ceiling Price (per MMBtu)	$9.00	$10.00	$8.75
Oil Options			
Volumes (MBbls)	1,009	930	—
Floor Price (per Bbl)	$55.00	$55.00	—
Average Ceiling Price (per Bbl)	$60.38	$57.03	—

(1) In July 2005, we paid a net premium of $30 million to raise the floor price on these contracts from $6.00 per MMBtu.
(2) We entered into these positions related to our announced acquisition of Medicine Bow.

In addition to the options described above, we hold several derivative contracts that, on a net basis, obligate us to sell natural gas at fixed prices on 3 TBtu of our Production segment's anticipated 2005 and 2006 natural gas production. The fair value of these production-related fixed price contracts and option contracts held at June 30, 2005 in the table above decreased by $12 million and $118 million during the quarter and six months ended June 30, 2005, due to increasing natural gas prices. In July 2005, we entered into several derivative contracts that obligate us to sell 34 TBtu of natural gas and 1,453 MBbls of oil at fixed prices related to the anticipated 2005 and 2006 natural gas and oil production from our announced acquisition of Medicine Bow.

- *Other natural gas derivatives.* Other natural gas derivatives consist of physical and financial natural gas contracts that impact our earnings as the fair value of these contracts change. These contracts obligate us to either purchase or sell natural gas at fixed prices. Our exposure to natural gas price changes will vary from period to period based on whether we purchase more or less natural gas than we sell under these contracts. Under certain of these contracts, we supply gas to power plants that we partially own. Due to their affiliated nature, we do not currently recognize mark-to-market gains or losses on these contracts to the extent of our ownership interests in the plants. However, should we sell our interests in these plants, we would be required to record the cumulative unrecognized mark-to-market losses on these contracts, which totaled approximately $106 million as of June 30, 2005, net of related hedges.

Transportation-related contracts

- Demand charges paid on our Alliance pipeline capacity contract were $16 million and $32 million in the quarter and six months ended June 30, 2005, versus $15 million and $30 million in the same periods of 2004. Our ability to use our Alliance pipeline capacity contract was relatively consistent during these periods, allowing us to recover approximately 66 percent of our demand charges in the first six months of 2005 and 65 percent in the first six months of 2004. This resulted from the price differentials between the receipt and delivery points remaining relatively consistent during these periods.

- Demand charges paid on our Texas Intrastate and remaining transportation contracts were $24 million and $47 million in the quarter and six months ended June 30, 2005, versus $25 million and $49 million in the same periods of 2004. Our ability to use the capacity under our Texas intrastate contracts improved in 2005 due to increased price differentials between the receipt and delivery points for the contracts. This allowed us to recover approximately 61 percent of the demand charges in the first six months of 2005 compared to only 18 percent during the same period in 2004. However, we only recovered 62 percent of the demand charges on our other transportation contracts in 2005 as compared to 70 percent in 2004, as price differentials between receipt and delivery points for these contracts decreased during the first six months of 2005.

Power Contracts

Cordova tolling agreement

Our Cordova agreement is sensitive to changes in forecasted natural gas and power prices. During 2005 and 2004, forecasted natural gas prices increased relative to power prices, resulting in a decrease in the fair value of the contract.

Other power derivatives

- During the first quarter of 2005, we assigned our contracts to supply power to our Power segment's Cedar Brakes I and II entities to Constellation Energy Commodities Group, Inc. These contracts decreased in fair value by $15 million and $38 million in the quarter and six months ended June 30, 2004. In conjunction with the transfer, we also entered into derivative contracts with Constellation that swap the locational differences in power prices at the Camden, Bayonne and Newark Bay power plants and the Pennsylvania-New Jersey-Maryland power pool's West Hub through 2013. The fair value of these swaps decreased by $6 million and $13 million during the quarter and six months ended June 30, 2005, due to unfavorable changes in the power prices at each location.

- We have a contract to supply power to Morgan Stanley at a fixed price through 2016. This contract increased in fair value by less than $1 million and $10 million during the quarters ended June 30, 2005 and 2004, and decreased in fair value by $90 million and $45 million during the six months ended June 30, 2005 and 2004. The overall decrease in the fair value of these derivatives during the six months ended June 30, 2005 and 2004 resulted from increasing power prices related to these obligations during these periods. However prices during the second quarters of 2005 and 2004 decreased.

- During the six months ended June 30, 2005 and 2004, we were required to purchase power under remaining power contracts, which include those used to manage the risk associated with our other power supply obligations. Due to changes in power prices, the fair value of these contracts decreased by $16 million and increased by $31 million during the quarter and six months ended June 30, 2005, and decreased by $13 million and increased by $70 million during the same periods of 2004.

- On March 24, 2005, a bankruptcy court entered an order allowing Mohawk River Funding III's (MRF III) bankruptcy claims with USGen New England. We received payment on this claim and recognized a gain of $17 million for amounts received in excess of receivables previously recorded.

Operating Expenses

Operating expenses were relatively consistent for the quarters and six months ended June 30, 2005 and 2004. We recorded a $1 million loss in 2005 related to additional payments delayed by the Berkshire power plant under their fuel supply agreement. Berkshire is no longer able to delay any future payments under this agreement. We continue to supply fuel to the plant under the fuel supply agreement and we may incur losses if amounts owed on future deliveries are not paid for under this agreement because of Berkshire's inability to generate adequate cash flow and the uncertainty surrounding their negotiations with their lenders. See Item 1, Financial Statements, Note 14 for additional information on this fuel supply agreement.

Non-regulated Business — Power Segment

As of June 30, 2005, our Power segment primarily consisted of an international power business. Historically, this segment also included domestic power plant operations and a domestic power contract restructuring business. We have sold substantially all of these domestic businesses. Our ongoing focus within the Power segment will be to maximize the value of our assets in Brazil. Our other international power operations are considered non-core activities, and we expect to exit these activities within the next twelve months.

Significant developments in our operations that occurred since December 31, 2004 include:

- *Brazil.* Our Macae project in Brazil has a contract that requires Petrobras to make minimum revenue payments until August 2007. Petrobras has not paid amounts due under the contract for December 2004 through the second quarter of 2005 and has initiated arbitration proceedings related to that obligation. For a further discussion of this matter, see Item 1, Financial Statements, Note 10. As a result of continued negotiations and discussions with Petrobras regarding this dispute, we recorded an impairment of this investment in the second quarter of 2005. This impairment was based on information regarding the potential value we would receive from the resolution of this matter. The future financial performance of the Macae plant will be affected by the ultimate outcome of this dispute, the timing of that outcome, and by regional changes in the Brazilian power markets.

- *Asia.* During the second and third quarters of 2005, we announced the sale of substantially all of our Asian power assets. We recorded impairments on certain of these assets based on information received regarding the potential value we may receive when we sell them. In July 2005, we completed the sale of our 50 percent interest in the KIECO power facility in Korea. The sale resulted in a gain of $109 million, which will be recorded in the third quarter of 2005. We expect to receive total proceeds of approximately $180 million from the sale of our remaining Asian assets, which we expect will be substantially completed by the end of 2005. We will continue to assess the fair value of those assets throughout the sales process, which may result in additional impairments or gains in future periods.

- *Other International Power.* During the second quarter of 2005, we engaged an investment banker to facilitate the sale of our Central American power assets. We recorded an impairment in the second quarter of 2005 based on information received about the value we may receive upon the sale of these assets. We will continue to assess the value of these assets throughout the sales process, which may result in additional impairments that may be significant. See Item 1, Financial Statements, Note 3 for further information on our divestitures.

Operating Results

Below are the overall operating results and analysis of activities within our Power segment for the periods ended June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
	(In millions)			
Overall EBIT:				
Gross margin[1]	$ 101	$ 194	$ 160	$ 354
Operating expenses				
Loss on long-lived assets	(361)	(16)	(388)	(256)
Other operating expenses	(97)	(122)	(167)	(246)
Operating loss	(357)	56	(395)	(148)
Earnings from unconsolidated affiliates				
Impairments, net of gains on sale	(87)	(15)	(148)	(38)
Equity in earnings	28	39	61	78
Other income	35	22	51	41
EBIT	$(381)	$ 102	$(431)	$ (67)

(1) Gross margin for our Power segment consists of revenues from our power plants and the revenues, cost of electricity purchases and changes in fair value of restructured power contracts. The cost of fuel used in the power generation process is included in operating expenses.

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
	(In millions)			
EBIT by Area:				
Brazil				
Impairments	$(294)	$ —	$(294)	$(151)
Earnings from consolidated and unconsolidated plant operations	12	50	26	106
Asia and Other International Power				
Impairments, net[1]	(161)	—	(258)	(5)
Dividend on investment fund	16	—	16	—
Gain on sale of PPN power plant	—	—	22	—
Earnings from consolidated and unconsolidated plant operations	11	20	31	36
Domestic Power				
Power Contract Restructurings:				
Favorable resolution of bankruptcy claim	53	—	53	—
Impairments, net[1]	—	—	—	(96)
Change in fair value of contracts	1	39	11	58
Other Domestic Operations	(10)	2	(8)	6
Other[2]	(9)	(9)	(30)	(21)
EBIT	$(381)	$102	$(431)	$ (67)

(1) Includes impairment charges and gains (losses) on sales of assets and investments, net of any related minority interest.

(2) Other consists of the indirect expenses and general and administrative costs associated with our domestic and international operations, including legal, finance and engineering costs. Direct general and administrative expenses of our domestic and international operations are included in EBIT of those operations. Other also includes gains and losses associated with our power turbine inventory. During the first quarter of 2005, we recorded a $15 million impairment of those turbines based on the receipt of further information about their fair value.

Brazil. In addition to the Macae impairment of $294 million, during the quarter and six months ended June 30, 2005 we did not recognize approximately $54 million and $99 million of our proportionate share of Macae's revenues based on non-payment of these amounts by Petrobras, which significantly affected our earnings at the plant. Partially offsetting the decline in Macae's earnings were lower insurance and general and administrative costs associated with our Brazilian operations. During the first quarter of 2004, we recorded an impairment of our Manaus and Rio Negro power plants based on the status of our negotiations to extend the power contracts, which was negatively impacted by changes in the Brazilian political environment.

Asia and Other International Power. During the second quarter of 2005, we recorded a $111 million impairment, net of related minority interest, on our Central American power assets and a $34 million impairment on our Asian assets. We also recorded $16 million of impairments, net of gains on sales, primarily related to our investments in power plants in Peru, England and Hungary based on the sale or anticipated sale of these projects. In the first quarter of 2005, we also recorded $97 million of impairments, which was primarily associated with our Asian assets based on ongoing sales negotiations.

In addition to these impairments, we did not recognize approximately $8 million and $19 million of our proportionate share of earnings for the quarter and six months ended June 30, 2005 on our Asian power investments since we did not believe these amounts could be realized. In a separate transaction, we also sold our interest in a power plant in India, which had previously been fully impaired. This sale resulted in a gain of $22 million in the first quarter of 2005.

Domestic Power Contract Restructurings. On March 24, 2005, a bankruptcy court entered an order allowing MRF III's bankruptcy claims with USGen New England. In June 2005, we received payment on this claim and recognized a gain of $53 million for amounts received in excess of receivables previously recorded.

With the completion of the sale of Cedar Brakes I and II in March 2005, we have sold substantially all of our domestic power contract restructuring business. As a result, in 2005, there was a substantial reduction in activity in these operations compared to changes in the fair value of these contracts that occurred during 2004. Our remaining operations include derivative contracts and related debt in Mohawk River Funding II (MRF II). We are currently evaluating opportunities to sell our interest in MRF II and our related power supply contracts, which may result in future losses. During the first quarter of 2004, we recorded a loss of $98 million related to the announced sale of Utility Contract Funding and its restructured power contract and related debt.

Other Domestic Operations. Our other domestic operations include:

- *MCV.* In 2004, we impaired our investment in MCV based on a decline in the value of the investment due to increased fuel costs. During the quarter ended June 30, 2005, we recorded a further impairment of $4 million based on a decrease in the fair value of the investment due to delays in the timing of expected cash flow receipts from this investment. After eliminating affiliated transactions, our proportionate share of MCV's reported losses during the second quarter of 2005 was $14 million and our proportionate share of their earnings during the six months ended June 30, 2005 was $58 million. A significant portion of these earnings (losses) related to mark-to-market changes recorded by MCV on their unaffiliated fuel supply contracts. We determined that these fair value changes did not increase or decrease the fair value of our equity investment and could not be realized in the future. Accordingly, we decreased our proportionate share of MCV's losses by $14 million during the second quarter of 2005 and decreased our proportionate share of their earnings by $57 million during the six months ended June 30, 2005. We will continue to assess our ability to recover our investment in MCV and its related operations in the future.

- *Other Domestic Assets.* During the quarter and six months ended June 30, 2004, we recorded earnings from consolidated and unconsolidated affiliates of approximately $41 million and $48 million and impairments of approximately $34 million and $45 million on our domestic power plants to adjust their book value to their estimated sales proceeds.

Non-regulated Business — Field Services Segment

Our Field Services segment has historically conducted our midstream activities. In 2004, these activities included our gathering and processing operations in south Texas and south Louisiana and our general and limited partner interests in GulfTerra and Enterprise. In January 2005, we sold our remaining common units and interest in the general partner of Enterprise and our interests in the Indian Springs natural gas gathering and processing assets to Enterprise. During the second quarter of 2005, our Board of Directors approved the sale of our south Louisiana gathering and processing assets, which we have reclassified as discontinued operations for the quarter and six months ended June 30, 2005. Prior period amounts have not been adjusted as these operations were not material to prior period results or historical trends.

For the quarter and six months ended June 30, 2005, EBIT in our Field Services segment was a loss of $3 million and earnings of $179 million as compared to earnings of $27 million and $63 million during the same periods of 2004 due to the following:

	Favorable (unfavorable) EBIT impact for the quarter ended June 30, 2005 compared to 2004	Favorable (unfavorable) EBIT impact for the six months ended June 30, 2005 compared to 2004
Gathering and processing margins	$(37)	$(79)
Operating expenses	25	59
Gain on sale of GP interest and common units to Enterprise	—	183
Other equity earnings	(30)	(68)
Minority interest	11	22
Other	1	(1)
Total increase (decrease) in EBIT	$(30)	$116

During the quarter and six months ended June 30, 2005, we experienced a decrease in our gathering and processing operations as compared to the same period in 2004, primarily as a result of asset sales.

For a discussion of our historical ownership interests in Enterprise and activities with the partnership, see Item 1, Financial Statements, Note 14. For a discussion of our discontinued operations associated with our gathering and processing assets, see Item 1, Financial Statements Note 3. For a further discussion of the historical business activities of our Field Services segment, see our 2004 Annual Report on Form 10-K, as amended.

Corporate, Net

Our corporate operations include our general and administrative functions as well as a telecommunications business and various other contracts and assets, all of which are immaterial to our results in 2005.

For the quarter and six months ended June 30, 2005, EBIT in our corporate operations was lower than the same periods in 2004 due to the following:

	Favorable (unfavorable) EBIT impact for quarter ended June 30, 2005 compared to 2004	Favorable (unfavorable) EBIT impact for six months ended June 30, 2005 compared to 2004
	(In millions)	
Western Energy Settlement charge in 2005[1]	$ —	$ (59)
Losses on early extinguishment of debt in 2005	—	(29)
Lease termination costs due to office consolidation	(27)	(27)
Change in litigation, insurance and other reserves	(1)	(16)
Other	7	(7)
Total decrease in EBIT	$ (21)	$(138)

(1) In the first quarter of 2005, we incurred this $59 million charge associated with the payment of the Western Energy Settlement obligation earlier than originally expected. This charge has been recorded in operations and maintenance expense.

We have a number of pending litigation matters, including shareholder and other lawsuits filed against us. In all of our legal and insurance matters, we evaluate each suit and claim as to its merits and our defenses. Adverse rulings against us and/or unfavorable settlements related to these and other legal matters would impact our future results.

As discussed in Item I, Financial Statements, Note 4, we had an accrual as of December 31, 2004 related to our remaining lease obligations associated with the consolidation of our Houston-based operations. Our estimated costs were based on a discounted liability, which included estimates of future sublease rentals. During the quarter and six months ended June 30, 2005, we recorded additional charges of $17 million related to vacating this remaining leased space to our downtown Houston location. In June 2005, we signed a termination agreement related to this lease obligation, which resulted in an additional charge of $10 million.

Interest and Debt Expense

Interest and debt expense for the quarter and six months ended June 30, 2005, was $70 million and $143 million lower than the same periods in 2004. Below is an analysis of our interest expense for the periods ended June 30:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
	(In millions)			
Long-term debt, including current maturities	$331	$391	$675	$795
Other	9	19	15	38
Total interest and debt expense	$340	$410	$690	$833

During the quarter and six months ended June 30, 2005, our total interest and debt expense decreased primarily due to the retirements of long-term debt and other financing obligations (net of issuances) during 2005 and 2004. See Item 1. Financial Statements, Note 9 for a further discussion of our activities related to debt repayments and issuances.

Income Taxes

Income taxes included in our income (loss) from continuing operations and our effective tax rates for the period ended June 30 were as follows:

	Quarter Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
	(In millions, except for rates)			
Income taxes	$(51)	$48	$(57)	$ 58
Effective tax rate	18%	59%	30%	(215)%

For a discussion of our effective tax rates, see Item 1, Financial Statements, Note 6.

In October 2004, the American Jobs Creation Act of 2004 was signed into law. This legislation creates, among other things, a temporary incentive for U.S. multinational companies to repatriate accumulated income earned outside the U.S. at an effective tax rate of 5.25%. The U.S. Treasury Department has indicated that additional guidance for applying the repatriation provisions of the American Jobs Creation Act of 2004 will be issued. We are currently evaluating whether we will repatriate any foreign earnings under the American Jobs Creation Act of 2004, and are evaluating the other provisions of this legislation, which may impact our taxes in the future.

Discontinued Operations

We have petroleum markets operations, international natural gas and oil production operations outside of Brazil, and gathering and processing operations in south Louisiana that are classified as discontinued operations in our financial statements. Our south Louisiana gathering and processing assets were approved for sale by our Board of Directors during the second quarter of 2005. Accordingly, these assets and the results of their operations for the quarter and six months ended June 30, 2005, have been reclassified as discontinued operations. Prior period amounts have not been adjusted as these operations did not materially impact prior period results or historical trends.

The loss from our discontinued operations for the second quarter of 2005 was $5 million compared to a loss of $29 million for the same period in 2004. The loss in 2005 consisted of losses of $11 million in our petroleum markets and international production operations and income of $6 million in our south Louisiana gathering and processing operations. The loss in 2004 consisted of losses of $14 million in our petroleum markets operations and $15 million in our international production operations.

The loss from our discontinued operations for the six months ended June 30, 2005 was $1 million compared to a loss of $106 million for the same period in 2004. The loss in 2005 consisted of losses of $13 million in our petroleum markets and international production operations and income of $12 million in our south Louisiana gathering and processing operations. The loss in 2004 consisted of losses of $77 million in our petroleum markets operations, primarily related to losses on the completed sales of our Eagle Point and Aruba refineries along with other operational and severance costs and $29 million of losses in our international production operations, primarily from impairments and losses on sales.

Commitments and Contingencies

See Item 1, Financial Statements, Note 10, which is incorporated herein by reference.

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

We have made statements in this document that constitute forward-looking statements, as that term is defined in the Private Securities Litigation Reform Act of 1995. Forward-looking statements include information concerning possible or assumed future results of operations. The words "believe," "expect," "estimate," "anticipate" and similar expressions will generally identify forward-looking statements. These statements may relate to information or assumptions about:

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

Forward-looking statements are subject to risks and uncertainties. While we believe the assumptions or bases underlying the forward-looking statements are reasonable and are made in good faith, we caution that assumed facts or bases almost always vary from actual results, and these variances can be material, depending upon the circumstances. We cannot assure you that the statements of expectation or belief contained in the forward-looking statements will result or be achieved or accomplished. Important factors that could cause actual results to differ materially from estimates or projections contained in forward-looking statements are described in our 2004 Annual Report on Form 10-K, as amended.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

This information updates, and you should read it in conjunction with, information disclosed in our 2004 Annual Report on Form 10-K, as amended, 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 2004 Annual Report on Form 10-K, as amended, except as presented below:

Market Risk

We are exposed to a variety of market risks in the normal course of our business activities, including commodity price, foreign exchange and interest rate risks. We measure risks on the derivative and non-derivative contracts in our trading portfolio on a daily basis using a Value-at-Risk model. We measure our Value-at-Risk using a historical simulation technique, and we prepare it based on a confidence level of 95 percent and a one-day holding period. This Value-at-Risk was $25 million as of June 30, 2005 and $16 million as of December 31, 2004, and represents our potential one-day unfavorable impact on the fair values of our trading contracts.

Interest Rate Risk

As of June 30, 2005 and December 31, 2004, we had $60 million and $665 million of third party long-term restructured power derivative contracts. In March 2005, we sold Cedar Brakes I and II, which held two power derivative contracts with a combined fair value of $596 million as of December 31, 2004. This sale substantially reduced our exposure to interest rate risks.

Item 4. Controls and Procedures

Material Weaknesses Previously Disclosed

As discussed in our 2004 Annual Report on Form 10-K, as amended, we did not maintain effective controls as of December 31, 2004, over (1) access to financial application programs and data in certain information technology environments, (2) account reconciliations and (3) identification, capture and communication of financial data used in accounting for non-routine transactions or activities. The remedial actions implemented in 2005 related to these material weaknesses are described below.

Evaluation of Disclosure Controls and Procedures

As of June 30, 2005, we carried out an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer (CEO) and our Chief Financial Officer (CFO), as to the effectiveness, design and operation of our disclosure controls and procedures (pursuant to Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act)). As discussed below, we have made various changes in our internal controls which we believe remediate the material weaknesses previously identified by the company. We are relying on those changes in internal controls as an integral part of our disclosure controls and procedures. Based upon the results of the evaluation of our disclosure controls and procedures and based upon our reliance on these revised internal controls, management, including our CEO and CFO, concluded that our disclosure controls and procedures were effective as of June 30, 2005.

Changes in Internal Control Over Financial Reporting

During the first quarter of 2005, we implemented the following changes in our internal control over financial reporting:

- Implemented automated and manual controls for our primary financial system to monitor unauthorized password changes;
- Developed a segregation of duties matrix for our primary financial system that documents existing role assignments;
- Formalized and issued a company-wide account reconciliation policy;
- Implemented an account reconciliation monitoring tool that also allows for aggregation of unreconciled amounts;
- Provided additional training regarding the company-wide account reconciliation policy and appropriate use of the account reconciliation monitoring tool;
- Developed a process to improve communication between commercial and accounting personnel to allow for complete and timely communication of information to record non-routine transactions related to divestiture activity; and
- Implemented an accounting policy that requires a higher level of review of non-routine transactions.

During the second quarter of 2005, we implemented the following changes in our internal control over financial reporting:

- Performed an in-depth analysis of the company's primary financial accounting system to examine existing functional access to identify any potentially incompatible duties.
- Enhanced the segregation of duties matrix for our primary financial accounting system based on the in-depth analysis of user access.
- Modified the primary financial accounting system to eliminate or modify potentially conflicting functionality.

- Rewrote the computer programs for Marketing and Trading's mark-to-market accounting system to significantly reduce the number of different combinations of user access and to modify remaining capabilities to eliminate potentially conflicting duties.

- Implemented a process to evaluate all new user access requests against segregation of duties matrices to ensure no new conflicts are created for our applications described above.

- Separated security administration rights from system update capabilities for our applications described above.

- Implemented monitoring procedures to monitor activities of security administration roles for our applications described above.

- Improved communications to establish the expectation that non-routine transactions must be communicated to ensure timely identification and thorough review of transactions.

- Established periodic business unit meetings to ensure relevant information related to non-routine transactions is captured and validated.

- Enhanced the Disclosure Committee Charter and meeting content to better address areas impacted by non-routine transactions, including discussion of impairments, significant estimates and legal and regulatory changes.

- Established a more rigorous top-down review of the financial statements at the management, corporate and Disclosure Committee levels.

We believe that the changes in our internal controls described above have remediated the material weaknesses. Our testing and an evaluation of the operating effectiveness and sustainability of the changes in internal controls has not been completed at this time. As a result, we may identify additional changes that are required to remediate or improve our internal controls over financial reporting.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Note 10, which is incorporated herein by reference. Additional information about our legal proceedings can be found in Part I, Item 3 of our 2004 Annual Report on Form 10-K, as amended, filed with the Securities and Exchange Commission.

Shoup Natural Gas Processing Plant. On December 16, 2003, El Paso Field Services, L.P. received a Notice of Enforcement (NOE) from the Texas Commission on Environmental Quality (TCEQ) concerning alleged Clean Air Act violations at its Shoup, Texas plant. The alleged violations pertained to exceeding the emission limit, testing, reporting, and recordkeeping issues in 2001. On December 29, 2004, TCEQ issued an Executive Director's Preliminary Report and Petition revising the allegations from the past NOE and seeking a penalty of $419,650. Following discussions with TCEQ, we have executed an agreed order to resolve the allegations for $202,400, which includes a $106,459 penalty payment to TCEQ and a $95,961 payment for a supplemental environmental project. We will make these payments once TCEQ has executed the agreed order.

Air Permit Violation. In March 2003, the Louisiana Department of Environmental Quality (LDEQ) issued a Consolidated Compliance Order and Notice of Potential Penalty to our subsidiary, El Paso Production Company, alleging that it failed to timely obtain air permits for specified oil and gas facilities. El Paso Production Company requested an adjudicatory hearing on the matter. Pursuant to discussions with LDEQ, we have reached an agreement in principle to resolve the allegations for $77,287. The parties are drafting the final settlement document formalizing the agreement.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None.

Item 3. Defaults Upon Senior Securities

None.

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

Proposals presented for a stockholders' vote at our Annual Meeting of Stockholders held on May 26, 2005, included the election of twelve directors, the approval of the El Paso Corporation 2005 Compensation Plan for Non-Employee Directors and the El Paso Corporation 2005 Omnibus Incentive Compensation Plan, and the ratification of the appointment of PricewaterhouseCoopers LLP as independent certified public accountants for the fiscal year 2005.

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

Nominee	FOR	WITHHELD
Juan Carlos Braniff	485,595,368	88,809,979
James L. Dunlap	541,603,167	32,802,181
Douglas L. Foshee	543,249,311	31,156,036
Robert W. Goldman	542,550,733	31,854,615
Anthony W. Hall Jr.	542,862,204	31,543,144
Thomas R. Hix	542,674,189	31,731,159
William H. Joyce	467,120,817	107,284,531
Ronald L. Kuehn, Jr.	538,531,144	35,874,204
J. Michael Talbert	541,856,536	32,548,812
Robert F. Vagt	543,436,611	30,968,737
John L. Whitmire	542,343,901	32,061,447
Joe B. Wyatt	542,582,667	31,822,681

The proposals to approve the El Paso Corporation 2005 Compensation Plan for Non-Employee Directors and the El Paso Corporation 2005 Omnibus Incentive Compensation Plan were adopted with the following voting results:

	FOR	AGAINST	ABSTAIN
Proposal to approve the El Paso Corporation 2005 Compensation Plan for Non-Employee Directors	406,537,306	31,591,247	5,942,757
Proposal to approve the El Paso Corporation 2005 Omnibus Incentive Compensation Plan	379,557,767	58,362,022	6,151,522

The appointment of PricewaterhouseCoopers LLP as El Paso's independent certified public accountants for the fiscal year 2005 was ratified with the following voting results:

	FOR	AGAINST	ABSTAIN
Proposal to ratify the appointment of PricewaterhouseCoopers LLP as independent certified public accountants	488,435,384	81,459,708	4,510,255

Item 5. Other Information

On August 4, 2005, we executed indemnification agreements with certain of our officers. These agreements reiterate the rights to indemnification that are provided to such officers under our by-laws, clarify procedures related to those rights, and provide that such rights are also available to fiduciaries under certain of our employee benefit plans. As is the case under the by-laws, the agreements provide for indemnification to the full extent permitted by Delaware law, including the right to be paid the reasonable expenses (including attorneys' fees) incurred in defending a proceeding related to service as an officer or fiduciary in advance of that proceeding's final disposition. We may maintain insurance, enter into contracts, create a trust fund or use other means available to provide for indemnity payments and advances. In the event of a change in control of El Paso (as defined in the indemnification agreements), we are obligated to pay the costs of independent legal counsel who will provide advice concerning the rights of each officer to indemnity payments and advances. We are filing as an exhibit to this report the form of indemnification agreement and list of senior officers and fiduciaries that entered into such agreement on August 4, 2005.

Item 6. 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 "*". Exhibits designated by "**" are furnished with this report pursuant to Item 601(b)(32) of Regulation S-K. All exhibits not so designated are incorporated herein by reference to a prior filing as indicated.

Exhibit Number	Description
3.A	Second Amended and Restated Certificate of Incorporation Stock (Exhibit 3.A to our Form 8-K filed on May 31, 2005).
3.B	Certificate of Designations of 4.99% Convertible Perpetual Preferred Stock (Exhibit 3.A to our Form 8-K filed on April 15, 2005).
4.A	Registration Rights Agreement, dated April 15, 2005, by and among El Paso Corporation and the Initial Purchasers party thereto (Exhibit 4.A to our Form 8-K filed on April 15, 2005).
4.B	Ninth Supplemental Indenture dated as of July 1, 2005 between El Paso Corporation and HSBC Bank USA, National Association, as trustee (Exhibit 4.A to our Form 8-K filed on July 1, 2005).
4.C	Form of 7.625% Senior Note Due August 16, 2007 (included in Exhibit 4.A to our Form 8-K filed July 1, 2005).
10.A	Purchase Agreement, dated April 11, 2005, by and among El Paso Corporation and the Initial Purchasers party thereto (Exhibit 10.A to our Form 8-K filed on April 15, 2005).
10.B	Agreement and General Release dated May 4, 2005, by and between El Paso Corporation and John W. Somerhalder II (Exhibit 10.A to our Form 8-K filed on May 4, 2005).
10.C	El Paso Corporation 2005 Compensation Plan for Non-Employee Directors (Exhibit 10.A to our Form 8-K filed on May 31, 2005).
10.D	El Paso Corporation 2005 Omnibus Incentive Compensation Plan (Exhibit 10.B to our Form 8-K filed on May 31, 2005).
*10.E	El Paso Corporation Employee Stock Purchase Plan, Amended and Restated Effective as of July 1, 2005.
10.F	Registration Rights Agreement dated as of July 1, 2005 between El Paso Corporation and Credit Suisse First Boston LLC (Exhibit 10.A to our Form 8-K filed on July 1, 2005).
*10.G	Form of Indemnification Agreement executed by El Paso for the benefit of each officer listed in Schedule A thereto, effective August 4, 2005.
*31.A	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.B	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
**32.A	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
**32.B	Certification of Chief Financial Officer pursuant to Section 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.

SIGNATURES

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

EL PASO CORPORATION

Date: August 5, 2005

/s/ D. DWIGHT SCOTT

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

Date: August 5, 2005

/s/ JEFFREY I. BEASON

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