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

Form 10-Q

(Mark One)

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

For the quarterly period ended March 31, 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 May 6, 2005: 644,556,445

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	TBtu	= trillion British thermal units
Mcf	= thousand cubic feet		

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

When we refer to "us", "we", "our", "ours", or "El Paso", 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 March 31,	
	2005	2004
Operating revenues	$1,208	$1,557
Operating expenses		
Cost of products and services	148	390
Operation and maintenance	448	401
Depreciation, depletion and amortization	281	275
Loss on long-lived assets	21	222
Taxes, other than income taxes	72	64
	970	1,352
Operating income	238	205
Earnings from unconsolidated affiliates	190	100
Other income, net	33	37
Interest and debt expense	(350)	(423)
Distributions on preferred interests of consolidated subsidiaries	(6)	(6)
Income (loss) before income taxes	105	(87)
Income taxes	(3)	10
Income (loss) from continuing operations	108	(97)
Discontinued operations, net of income taxes	(2)	(109)
Net income (loss)	$ 106	$ (206)
Basic and diluted income (loss) per common share		
Income (loss) from continuing operations	$ 0.17	$(0.15)
Discontinued operations, net of income taxes	—	(0.17)
Net income (loss) per common share	$ 0.17	$(0.32)
Basic average common shares outstanding	640	638
Diluted average common shares outstanding	642	638
Dividends declared per common share	$ 0.04	$ 0.04

See accompanying notes.

EL PASO CORPORATION

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

	March 31, 2005	December 31, 2004
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,651	$ 2,117
Accounts and notes receivable		
Customers, net of allowance of $199 in 2005 and 2004	1,285	1,388
Affiliates	73	133
Other	193	188
Inventory	137	168
Assets from price risk management activities	740	601
Assets held for sale and from discontinued operations	147	181
Deferred income taxes	670	418
Other	386	438
Total current assets	5,282	5,632
Property, plant and equipment, at cost		
Pipelines	19,405	19,418
Natural gas and oil properties, at full cost	15,485	14,968
Power facilities	1,058	1,534
Gathering and processing systems	168	171
Other	609	882
	36,725	36,973
Less accumulated depreciation, depletion and amortization	17,814	18,161
Total property, plant and equipment, net	18,911	18,812
Other assets		
Investments in unconsolidated affiliates	2,403	2,614
Assets from price risk management activities	1,205	1,584
Goodwill and other intangible assets, net	429	428
Other	2,305	2,313
	6,342	6,939
Total assets	$30,535	$31,383

See accompanying notes.

EL PASO CORPORATION

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

	March 31, 2005	December 31, 2004
Current liabilities		
Accounts payable		
Trade	$ 851	$ 1,052
Affiliates	66	21
Other	472	483
Short-term financing obligations, including current maturities	850	955
Liabilities from price risk management activities	1,196	852
Western Energy Settlement	442	44
Accrued interest	313	333
Other	766	832
Total current liabilities	4,956	4,572
Long-term financing obligations, less current maturities	16,927	18,241
Other		
Liabilities from price risk management activities	1,339	1,026
Deferred income taxes	1,628	1,311
Western Energy Settlement	—	351
Other	1,997	2,076
	4,964	4,764
Commitments and contingencies		
Securities of subsidiaries	365	367
Stockholders' equity		
Common stock, par value $3 per share; authorized 1,500,000,000 shares; issued 651,097,680 shares in 2005 and 651,064,508 shares in 2004	1,953	1,953
Additional paid-in capital	4,513	4,538
Accumulated deficit	(2,749)	(2,855)
Accumulated other comprehensive income (loss)	(151)	48
Treasury stock (at cost); 8,161,454 shares in 2005 and 7,767,088 shares in 2004	(230)	(225)
Unamortized compensation	(13)	(20)
Total stockholders' equity	3,323	3,439
Total liabilities and stockholders' equity	$30,535	$31,383

See accompanying notes.

EL PASO CORPORATION

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

	Quarter Ended March 31,	
	2005	2004
Cash flows from operating activities		
Net income (loss)	$ 106	$ (206)
Less loss from discontinued operations, net of income taxes	(2)	(109)
Net income (loss) before discontinued operations	108	(97)
Adjustments to reconcile net income (loss) to net cash from operating activities		
Depreciation, depletion and amortization	281	275
Loss on long-lived assets	21	222
Earnings from unconsolidated affiliates, adjusted for cash distributions	(107)	(10)
Deferred income taxes	45	(45)
Other non-cash items	28	24
Asset and liability changes	(312)	118
Cash provided by continuing operations	64	487
Cash provided by (used in) discontinued operations	(13)	142
Net cash provided by operating activities	51	629
Cash flows from investing activities		
Additions to property, plant and equipment	(391)	(372)
Purchases of interests in equity investments	(3)	(11)
Net proceeds from the sale of assets and investments	633	24
Proceeds from settlement of a foreign currency derivative	131	—
Cash paid for acquisitions, net of cash acquired	(173)	—
Net change in restricted cash	75	(124)
Other	9	43
Cash provided by (used in) continuing operations	281	(440)
Cash provided by discontinued operations	74	1,057
Net cash provided by investing activities	355	617
Cash flows from financing activities		
Payments to retire long-term debt and other financing obligations	(1,039)	(576)
Net repayments under short-term debt and credit facilities	(1)	—
Net proceeds from the issuance of long-term debt and other financing obligations	197	50
Dividends paid	(26)	(23)
Contributions from discontinued operations	61	834
Issuances of common stock, net	—	73
Other	(3)	(16)
Cash provided by (used in) continuing operations	(811)	342
Cash used in discontinued operations	(61)	(1,199)
Net cash used in financing activities	(872)	(857)
Change in cash and cash equivalents	(466)	389
Cash and cash equivalents		
Beginning of period	2,117	1,429
End of period	$ 1,651	$ 1,818

See accompanying notes.

EL PASO CORPORATION

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

	Quarter Ended March 31, 2005	Quarter Ended March 31, 2004
Net income (loss)	$ 106	$(206)
Foreign currency translation adjustments (net of income taxes of $1 in 2005 and less than $1 in 2004)	11	14
Unrealized net gains (losses) from cash flow hedging activity		
Unrealized mark-to-market losses arising during period (net of income taxes of $102 in 2005 and $10 in 2004)	(189)	(19)
Reclassification adjustments for changes in initial value to the settlement date (net of income taxes of $13 in 2005 and $8 in 2004)	(21)	15
Other comprehensive income (loss)	(199)	10
Comprehensive loss	$ (93)	$(196)

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 Annual Report on Form 10-K for the fiscal year ended December 31, 2004, as amended on April 8, 2005 and May 6, 2005, which includes a summary of our significant accounting policies and other disclosures. The financial statements as of March 31, 2005, and for the quarters ended March 31, 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. In mid 2004, we discontinued our Canadian and certain other international natural gas and oil production operations. Our results for all periods reflect these operations as discontinued.

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 required a company to consolidate a variable interest entity if it is allocated a majority of the entity's losses or returns, 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 quarters ended March 31, 2005 and 2004 and as of March 31, 2005 and December 31, 2004:

	2005	2004
	(In millions)	
Operating revenues	$(33)	$15
Current liabilities from price risk management activities	23	20
Non-current liabilities from price risk management activities	53	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 March 31,	
	2005	2004
	(In millions)	
Net income (loss) as reported	$ 106	$ (206)
Add: Stock-based compensation expense in net income (loss), net of taxes	2	4
Deduct: Stock-based compensation expense determined under fair value-based method for all awards, net of taxes	5	10
Pro forma net income (loss)	$ 103	$ (212)
Income (loss) per share:		
Basic and diluted, as reported	$0.17	$(0.32)
Basic and diluted, pro forma	$0.16	$(0.33)

New Accounting Pronouncements Issued But Not Yet Adopted

As of March 31, 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. However, companies are permitted to adopt the standard early. Upon adoption, we can select whether to apply the standard retroactively by restating our historical financial statements or prospectively for new stock-based compensation arrangements and the unvested portion of existing arrangements. We are currently evaluating the timing of our adoption and the impact of this standard 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 not issued final guidelines for applying the repatriation provisions of the American Jobs Creation Act. 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 FASB Interpretation (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 or amount of settlement of the obligation are uncertain. These conditional obligations were not addressed by SFAS No. 143, which we adopted on January 1, 2003. FIN No. 47 will require us to accrue a liability when a range of scenarios indicate that the potential timing and 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.

2. Divestitures

Sales of Assets and Investments

During the quarters ended March 31, 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[1]	$ 32	$ 2
Non-regulated		
Power	110	6
Field Services	501	—
Other		
Corporate	—	8
Total continuing[2]	643	16
Discontinued	79	1,243
Total	$722	$1,259

(1) Proceeds are non-cash assets received in connection with the transfer of certain pipeline and measurement facilities pursuant to definitive agreements extending firm transportation service contracts with a pipeline customer.

(2) Proceeds exclude returns of capital from unconsolidated affiliates and cash transferred with the assets sold and include costs incurred for disposal. These decreased our sales proceeds by $10 million for the quarter ended March 31, 2005 and increased our sales proceeds by $8 million for the quarter ended March 31, 2004.

The following table summarizes the significant assets sold during the quarters ended March 31:

	2005	2004
Pipelines	• Facilities located in the southeastern U.S.	• Aircraft
Power	• Interests in Cedar Brakes I and II • Interest in a power plant in India • Eagle Point power facility • Rensselaer power facility	• Mohawk River Funding IV
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	• None	• Aircraft
Discontinued	• Interest in Paraxylene facility • MTBE processing facility	• Natural gas and oil production properties in Canada • Aruba and Eagle Point refineries

In April 2005, we also completed the sale of our interest in the Enfield power facility in England for approximately $50 million, the sale of a power turbine for $15 million and the sale of real estate for $2 million.

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 March 31, 2005, we had assets held for sale of $122 million related to our Lakeside Technology Center and certain domestic power assets which were fully impaired in previous years and which we expect to sell 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 were sold in the first quarter of 2005 and certain domestic power assets.

Discontinued Operations

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 expect to complete the sale of the remainder of these properties in 2005.

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 and other international natural gas and oil production operations discussed above are classified as discontinued operations in our financial statements. All of the assets and liabilities of these discontinued businesses are classified as current assets and liabilities as of March 31, 2005 and December 31, 2004. The summarized financial results and financial position data of our discontinued operations were as follows:

	Petroleum Markets	International Natural Gas and Oil Production Operations	Total
		(In millions)	
Operating Results Data			
Quarter Ended March 31, 2005			
Revenues	$ 44	$ 2	$ 46
Costs and expenses	(53)	(1)	(54)
Gain (loss) on long-lived assets	3	(1)	2
Other income	15	—	15
Income before income taxes	9	—	9
Income taxes	12	(1)	11
Income (loss) from discontinued operations, net of income taxes	$ (3)	$ 1	$ (2)
Quarter Ended March 31, 2004			
Revenues	$ 639	$ 27	$ 666
Costs and expenses	(653)	(44)	(697)
Loss on long-lived assets	(42)	(93)	(135)
Other expense	(2)	—	(2)
Interest and debt expense	(3)	1	(2)
Loss before income taxes	(61)	(109)	(170)
Income taxes	(6)	(55)	(61)
Loss from discontinued operations, net of income taxes	$ (55)	$ (54)	$(109)

	Petroleum Markets	International Natural Gas and Oil Production Operations	Total
		(In millions)	
Financial Position Data			
March 31, 2005			
Assets of discontinued operations			
Accounts and notes receivable	$ —	$ 1	$ 1
Inventory	2	—	2
Other current assets	1	1	2
Property, plant and equipment, net	12	5	17
Other non-current assets	3	—	3
Total assets	$ 18	$ 7	$ 25
Liabilities of discontinued operations			
Accounts payable	$ 2	$ 1	$ 3
Other current liabilities	2	—	2
Other non-current liabilities	3	—	3
Total liabilities	$ 7	$ 1	$ 8
December 31, 2004			
Assets of discontinued operations			
Accounts and notes receivable	$ 39	$ 2	$ 41
Inventory	8	—	8
Other current assets	3	1	4
Property, plant and equipment, net	14	6	20
Other non-current assets	33	—	33
Total assets	$ 97	$ 9	$ 106
Liabilities of discontinued operations			
Accounts payable	$ 5	$ 1	$ 6
Other current liabilities	3	—	3
Other non-current liabilities	3	—	3
Total liabilities	$ 11	$ 1	$ 12

3. Restructuring Costs

During 2004, 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. In May 2004, we announced that we would consolidate our Houston-based operations into one location. This consolidation was substantially completed by the end of 2004. As a result, as of December 31, 2004, we had established an accrual totaling $80 million to record the discounted liability, net of estimated sub-lease rentals, for our obligations under our existing lease terms. These leases expire at various times through 2014. Of the approximate 888,000 square feet of office space that we lease, we have vacated approximately 741,000 square feet as of March 31, 2005. In addition, we have subleased approximately 238,000 square feet of this space. Actual moving expenses related to the relocation were insignificant and were expensed in the period that they were incurred. All amounts related to the relocation are expensed in our corporate operations. We will incur additional charges as we vacate the remaining space that we lease, and estimate that the total additional accrual and charge could be $10 million to $20 million. In addition, we are currently reviewing our options regarding early release from the lease obligation, which if completed in its current form, will result in a further increase in amounts we have accrued. Based on current negotiations, the termination and early release of our obligations could result in additional accruals of $15 million to $20 million.

Employee severance, retention, and transition costs. During the quarter ended March 31, 2004, we incurred $27 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. As of March 31, 2005, all but $12 million of the total employee severance, retention and transition costs had been paid.

4. 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 the quarters ended March 31, our loss on long-lived assets was as follows:

	2005	2004
	(In millions)	
Net realized gain	$ (7)	$ (8)
Asset impairments	28	230
Loss on long-lived assets	21	222
(Gain) loss on investments in unconsolidated affiliates[1]	(119)	19
(Gain) loss on long-lived assets and investments	$ (98)	$ 241

[1] See Note 16 for a further description of these gains and losses.

Net Realized Gain

Our 2005 net realized gains are primarily related to a gain on the sale of facilities located in the southeastern United States in our Pipelines segment. Our 2004 net realized gains are primarily related to a gain on aircraft sales associated with our corporate activities.

Asset Impairments

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 and a $14 million impairment of our Asian assets based on additional information received during the sales process.

In the first quarter of 2004, our Power segment recorded a $135 million impairment 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. Our Power segment also recorded a $98 million impairment charge related to the sale of our subsidiary, Utility Contract Funding, which owned a restructured power contract.

5. Income Taxes

Income taxes included in our income (loss) from continuing operations for the quarters ended March 31 were as follows:

	2005	2004
	(In millions, except rates)	
Income taxes	$(3)	$ 10
Effective tax rate	(3)%	(11)%

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 the first quarter of 2005, our overall effective tax rate on continuing operations was negative (i.e. there was an overall tax benefit in a period in which there was income) due primarily to a $30 million reduction in our liabilities for tax contingencies as a result of an IRS settlement on the 1995 to 1997 Coastal Corporation income tax returns. Also impacting our effective tax rate were tax benefits recognized on the sale of a foreign investment and state tax adjustments to reflect income tax returns as filed. Partially offsetting these items was the tax impact of an impairment of certain of our foreign investments for which there was no corresponding tax benefit. During the first quarter of 2004, our overall effective tax rate on continuing operations was negative due primarily to the impairment of certain of our foreign investments for which there was no corresponding tax benefit.

6. Earnings Per Share

We calculated basic and diluted earnings per common share amounts as follows for the quarters ended March 31:

	2005		2004	
	Basic	Diluted	Basic	Diluted
	(In millions, except per common share amounts)			
Income (loss) from continuing operations	$ 108	$ 108	$ (97)	$ (97)
Discontinued operations, net of income taxes	(2)	(2)	(109)	(109)
Adjusted net income (loss)	$ 106	$ 106	$ (206)	$ (206)
Average common shares outstanding	640	640	638	638
Effect of dilutive securities				
Stock options	—	1	—	—
Restricted stock	—	1	—	—
Adjusted average common shares outstanding	640	642	638	638
Earnings per common share				
Income (loss) from continuing operations	$0.17	$0.17	$(0.15)	$(0.15)
Discontinued operations, net of income taxes	—	—	(0.17)	(0.17)
Adjusted net income (loss)	$0.17	$0.17	$(0.32)	$(0.32)

We exclude potentially dilutive securities from the determination of diluted earnings per share (as well as their related income statement impacts) when their impact on income (loss) per common share is antidilutive. For the quarter ended March 31, 2004, all of our securities were antidilutive due to our loss from continuing operations. For the quarter ended March 31, 2005, we excluded our equity security units, trust preferred securities, and convertible debentures based on their antidilutive impact. Our diluted earnings per share could be negatively impacted by a proposed accounting standard that would affect the manner in which certain redemption features of our convertible debentures are treated for earnings per share calculations. For a further discussion of these convertible debentures, as well as other instruments, refer to our 2004 Annual Report on Form 10-K, as amended.

7. Price Risk Management Activities

The following table summarizes the carrying value of the derivatives used in our price risk management activities as of March 31, 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.

	March 31, 2005	December 31, 2004
	(In millions)	
Net assets (liabilities)		
Derivatives designated as hedges	$(760)	$(536)
Derivatives from power contract restructuring activities[1]	65	665
Other commodity-based derivative contracts[1]	46	(61)
Total commodity-based derivatives	(649)	68
Interest rate and foreign currency hedging derivatives[2]	59	239
Net assets (liabilities) from price risk management activities[3]	$(590)	$ 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.

8. Inventory

We have the following inventory recorded on our balance sheets:

	March 31, 2005	December 31, 2004
	(In millions)	
Materials and supplies and other	$128	$130
Natural gas liquids and natural gas in storage	9	38
Total inventory	$137	$168

9. Western Energy Settlement

As of December 31, 2004 and March 31, 2005, we had a liability of $395 million and $442 million related to a 20 year cash payment obligation that arose out of the Western Energy Settlement. In the first quarter of 2005, we incurred a charge of approximately $59 million in operation and maintenance expense in our corporate operations associated with the anticipated payment of this obligation earlier than originally expected. In April 2005, we prepaid this deferred obligation.

10. Debt, Other Financing Obligations and Other Credit Facilities

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

	March 31, 2005	December 31, 2004
	(In millions)	
Short-term financing obligations, including current maturities	$ 850	$ 955
Long-term financing obligations	16,927	18,241
Total	$17,777	$19,196

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
	Increases through March 31, 2005		200	197
Cheyenne Plains Gas Pipeline Company[1]	Non-recourse term loan due 2015	Variable	266	261
	Increases through filing date		$ 466	$ 458
Repayments, repurchases, retirements and other				
El Paso	Zero coupon debenture	—[2]	$ 185	$ 187
Cedar Brakes I[3]	Non-recourse notes	8.5%	226	15
Cedar Brakes II[3]	Non-recourse notes	9.88%	320	14
El Paso[4]	Euro notes	5.75%	695	722
Other	Long-term debt	Various	193	101
	Decreases through March 31, 2005		1,619	1,039
El Paso	Long-term debt	Various	5	5
	Decreases through filing date		$1,624	$1,044

(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 balance of the debt obligations was eliminated.

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

Credit Facilities

As of March 31, 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.

Letters of Credit

As of March 31, 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 credit securing our recorded obligations related to price risk management activities.

11. 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). These agreements included a Joint Settlement Agreement or JSA where we agreed to certain conditions regarding service and facilities on 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 Federal Energy Regulatory Commission (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. We expect this appeal to be fully briefed by the summer of 2005.

Shareholder/Derivative/ERISA Litigation

Shareholder Litigation. Since 2002, 29 purported shareholder class action lawsuits alleging violations of federal securities laws have been filed against us and several of our current and former officers and directors. One of these lawsuits has been dismissed and the remaining 28 lawsuits have been consolidated in federal court in Houston, Texas. The consolidated lawsuit generally challenges 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. 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. These actions are currently stayed. Two actions are now consolidated in state court in Houston, Texas and generally allege that the manipulation of California gas prices exposed us to claims of antitrust conspiracy, FERC penalties and erosion of share value. A 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. This lawsuit has been 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 the all residential and commercial purchasers of natural gas in the state of Tennessee during the past three years. 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; and *Abelman Art Glass, et al. v. Encana Corporation, et al.* was filed in December 2004. 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. The plaintiff in this case seeks royalties that he contends the government should have received had the volume and heating value been differently measured, analyzed, calculated and reported, together with interest, treble damages, civil penalties, expenses and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. These matters have been consolidated for pretrial purposes (*In re: Natural Gas Royalties Qui Tam Litigation,* U.S. District Court for the District of Wyoming, filed June 1997). Motions to dismiss have been briefed and argued and the parties are awaiting the court's ruling. 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 seek an accounting and damages for 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, as well as punitive damages. The court has certified the plaintiff classes of royalty and overriding royalty interest owners. The plaintiffs have filed expert reports alleging damages in excess of $1 billion. Pursuant to a recent summary judgment decision, the court ruled that claims previously released by the settlement of *Altheide v. Meridian,* a nation-wide royalty class action against Burlington and its affiliates are barred from being reasserted in this action. We believe that this ruling eliminates a material, but yet unquantified portion of the alleged class damages. The consolidated class action has been set for trial in the third 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. 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. A Curitiba court has ruled that the arbitration clause in the PPA is invalid, and has enjoined the project company from prosecuting its arbitration under penalty of approximately $173,000 in daily fines. The project company is appealing this ruling, and has obtained a stay order in any imposition of daily fines pending the outcome of the appeal. Our investment in the Araucaria project was $186 million at March 31, 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 with property, plant and equipment having a net book value of $694 million as of March 31, 2005. 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. Beginning in December 2004, and continuing through the first quarter of 2005, Petrobras has failed to make payments that were due under the participation agreement. In February 2005, Petrobras obtained a ruling from a Brazilian court directing Petrobras to deposit one-half of the payments to a court account and to pay us the other half. This ruling was vacated by another Brazilian court in April 2005 due to Petrobras' failure to pay the amounts in accordance with the ruling. Due to this ongoing dispute, we have not recognized approximately $45 million of revenues under our participation agreement in the first quarter of 2005, due to the uncertainty about their collectibility. 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's obligation to provide a firm gas supply to the project through 2012. 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 $275 million at March 31, 2005, and Petrobras' non-payment has created an event of default under the applicable loan agreements. As a result, we have classified the entire $275 million of debt as current. We also have restricted cash balances of approximately $22 million as of March 31, 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, we have evaluated whether any impairment of our interest in the long-lived assets of the project and our remaining accounts receivable from Petrobras of $24 million, is required at March 31, 2005. Based upon our review of the possible outcomes of the arbitration and potential settlements of the dispute, and despite the fact that we have not recognized revenues under the participation agreement in the first quarter of 2005, we do not believe that an impairment of these interests is required at this time. However, if our assessment of the potential outcomes of the arbitration or settlement opportunities changes, we may be required to write down some or all of the project's long-lived assets and accounts receivable. In the event that the lenders call the loans and ultimately foreclose on the project, our loss would be approximately $479 million as of March 31, 2005. 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 or are in the process of being 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. 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 employment and other agreements by failing to make certain payments to him following his departure from El Paso in 2003. Mr. Wise seeks approximately $20 million in additional compensation. Discovery is underway, with a hearing scheduled in the summer of 2005.

Government Investigations

Power Restructuring. In October 2003, we announced that the SEC had authorized the staff of the Fort Worth Regional Office to conduct an investigation of certain aspects of our periodic reports filed with the SEC. The investigation appears to be focused principally on 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. We have cooperated with the SEC 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.

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. We are cooperating with the SEC's and the U.S. Attorney's investigations of this matter.

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 relating 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. 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 five 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. In addition, we, EPNG and several of its current and former employees have received several federal grand jury subpoenas for documents or testimony related to the Carlsbad rupture. We are cooperating with the Department of Justice's investigation of this matter.

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

Accounting for Pipeline Integrity Costs. In November 2004, the FERC issued a proposed accounting release that may impact certain costs our interstate pipelines incur related to their pipeline integrity programs. If the release is enacted as written, we would be required to expense certain future pipeline integrity costs instead of capitalizing them as part of our property, plant and equipment. Although we continue to evaluate the impact of this potential accounting release, we currently estimate that if the release is enacted as written, we would be required to expense an additional amount of pipeline integrity expenditures in the range of approximately $25 million to $41 million annually over the next eight years.

Selective Discounting Notice of Inquiry. In November 2004, the FERC issued a NOI seeking comments on its policy regarding selective discounting by natural gas pipelines. The FERC seeks comments regarding whether its practice of permitting pipelines to adjust their ratemaking throughput downward in rate cases to reflect discounts given by pipelines for competitive reasons is appropriate when the discount is given to meet competition from another natural gas pipeline. Our pipelines filed comments on the NOI. Neither the final outcome of this inquiry nor the impact on our pipelines can be predicted with certainty.

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 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. The outcome of this process is uncertain, but we may incur higher future costs arising from potential litigation or increased right-of-way fees.

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 $1.6 billion as of March 31, 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. 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 PPAs 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 replace or 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 $303 million at March 31, 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 March 31, 2005, we had approximately $624 million accrued, net of related insurance receivables, for all outstanding legal and other contingent matters, including amounts accrued for our Western Energy Settlement.

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 March 31, 2005, we had accrued approximately $383 million, including approximately $371 million for expected remediation costs and associated onsite, offsite and groundwater technical studies, and approximately $12 million for related environmental legal costs, which we anticipate incurring through 2027. Of the $383 million accrual, $102 million was reserved for facilities we currently operate, and $281 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 $383 million to approximately $547 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 ($85 million). Second, where the most likely outcome cannot be estimated, a range of costs is established ($298 million to $462 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.

	March 31, 2005	
Sites	Expected	High
	(In millions)	
Operating	$102	$115
Non-operating	252	383
Superfund	29	49
Total	$383	$547

Below is a reconciliation of our accrued liability from January 1, 2005, to March 31, 2005 (in millions):

Balance as of January 1, 2005	$380
Additions/adjustments for remediation activities	13
Payments for remediation activities	(11)
Other changes, net	1
Balance as of March 31, 2005	$383

For the remainder of 2005, we estimate that our total remediation expenditures will be approximately $66 million. In addition, we expect to make capital expenditures for environmental matters of approximately $63 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 March 31, 2005, TGP had pre-collected PCB costs by approximately $127 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 March 31, 2005, TGP has recorded a regulatory liability (included in other non-current liabilities on its balance sheet) of $99 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 53 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 March 31, 2005, we have estimated our share of the remediation costs at these sites to be between $29 million and $49 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, the environment and 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 relating 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 guarantees. As of March 31, 2005, we had approximately $30 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 March 31, 2005, we had accrued $65 million related to these arrangements.

12. Preferred Interests of Consolidated Subsidiaries

As March 31, 2005, our subsidiary, El Paso Tennessee Pipeline Co. (EPTP) had $300 million of 8.25% Series A cumulative preferred stock outstanding. In April 2005, EPTP gave notice of its intent to redeem its preferred stock in May 2005 for $300 million plus accrued dividends.

13. Retirement Benefits

The components of net benefit cost for our pension and postretirement benefit plans for the quarters ended March 31 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2005	2004	2005	2004
	(In millions)			
Service cost	$ 6	$ 8	$—	$—
Interest cost	29	31	7	8
Expected return on plan assets	(42)	(48)	(3)	(3)
Amortization of net actuarial loss	16	12	—	1
Amortization of transition obligation	—	—	2	2
Amortization of prior service cost[1]	(1)	(1)	—	—
Net benefit cost	$ 8	$ 2	$ 6	$ 8

[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 $2 million for the first quarter of 2005. Our actual and expected contributions for 2005 were not reduced by subsidies under this legislation.

We made $18 million and $15 million of cash contributions to our Supplemental Executive Retirement Plan (SERP) and other postretirement plans during the quarters ended March 31, 2005 and 2004. We expect to contribute an additional $4 million to the SERP and $47 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.

14. Capital Stock

Dividends

During the quarter ended March 31, 2005, we paid dividends of approximately $26 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. On April 28, 2005, the Board of Directors declared a quarterly dividend of $0.04 per share on our outstanding common stock. This dividend is payable July 5, 2005 to shareholders of record on June 3, 2005. We expect dividends paid on our common stock in 2005 will be taxable to our common stockholders because we anticipate that these dividends will be paid out of current or accumulated earnings and profits for tax purposes.

In addition, El Paso Tennessee Pipeline Co., our subsidiary, paid dividends (2.0625% per quarter, 8.25% per annum) of approximately $6 million on its Series A cumulative preferred stock.

Convertible Perpetual Preferred Stock

In April 2005, we issued $750 million of convertible perpetual preferred stock. Cash dividends on the preferred stock will be paid quarterly at the rate of 4.99% per annum. Each share of the preferred stock will be 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.

15. 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 2004, we reclassified our Canadian and certain other international natural gas and oil production operations from our Production segment to discontinued operations in our financial statements. Our operating results for all periods presented reflect these operations as discontinued.

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 quarters ended March 31:

	2005	2004
	(In millions)	
Total EBIT	$ 461	$ 342
Interest and debt expense	(350)	(423)
Distributions on preferred interests of consolidated subsidiaries	(6)	(6)
Income taxes	3	(10)
Income (loss) from continuing operations	$ 108	$ (97)

The following tables reflect our segment results as of and for the quarters ended March 31:

	Regulated	Non-regulated					
	Pipelines	Production	Marketing and Trading	Power	Field Services	Corporate[1]	Total
			(In millions)				
2005							
Revenues from external customers	$748	$131[2]	$ 93	$ 79	$130	$ 27	$1,208
Intersegment revenues	20	308[2]	(268)	(2)	6	(64)	—
Operation and maintenance	203	84	10	51	5	95	448
Depreciation, depletion and amortization	111	146	1	12	2	9	281
(Gain) loss on long-lived assets	(7)	—	—	27	1	—	21
Operating income (loss)	$362	$180	$(186)	$ (38)	$ 11	$(91)	$ 238
Earnings (losses) from unconsolidated affiliates	38	—	—	(28)	180	—	190
Other income, net	12	3	1	16	—	1	33
EBIT	$412	$183	$(185)	$ (50)	$191	$(90)	$ 461
2004							
Revenues from external customers	$698	$133[2]	$ 181	$ 149	$345	$ 43	$1,549
Intersegment revenues	23	313[2]	(340)	58	42	(88)	8[3]
Operation and maintenance	180	85	13	97	26	—	401
Depreciation, depletion and amortization	100	140	3	16	3	13	275
(Gain) loss on long-lived assets	(1)	—	—	224	2	(3)	222
Operating income (loss)	$348	$203	$(175)	$(188)	$ 10	$ 7	$ 205
Earnings from unconsolidated affiliates	33	1	—	29	37	—	100
Other income (expense), net	5	—	3	20	(11)	20	37
EBIT	$386	$204	$(172)	$(139)	$ 36	$ 27	$ 342

(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 March 31, 2005 and 2004, we recorded an intersegment revenue elimination of $64 million and $88 million and an operations and maintenance expense elimination of less than $1 million and $8 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:

	March 31, 2005	December 31, 2004
	(In millions)	
Regulated		
Pipelines	$16,085	$15,988
Non-regulated		
Production	4,457	4,080
Marketing and Trading	2,627	2,404
Power	3,003	3,599
Field Services	309	686
Total segment assets	26,481	26,757
Corporate	4,029	4,520
Discontinued operations	25	106
Total consolidated assets	$30,535	$31,383

16. 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, power generation plants, and gathering systems. 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	
	March 31,	Quarter Ended March 31,	
	2005	2005	2004
	(Percent)	(In millions)	
Domestic:			
Enterprise Products Partners[1]	—	$183	$ —
GulfTerra Energy Partners[1]	—	—	34
Citrus	50	15	7
Midland Cogeneration Venture (MCV)[2]	44	1	5
Great Lakes Gas Transmission	50	17	20
Other Domestic Investments	various	3	2
Total domestic		219	68
Foreign:			
Asia Investments[3]	various	(68)	29
PPN[4]	—	22	—
Other Foreign Investments	various	17	3
Total foreign		(29)	32
Total earnings from unconsolidated affiliates		$190	$100

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

(2) Our proportionate share of the earnings reported by MCV was $92 million for the quarter ended March 31, 2005, largely due to changes in accounting for derivative contracts. We decreased our proportionate share of equity earnings for MCV by $20 million to eliminate affiliated transactions and by $71 million to reflect the amount of earnings that we believe will be realized.

(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 $25 million for the quarter ended March 31, 2005. We decreased our proportionate share of equity earnings for our Asia investments by $11 million to reflect the amount of earnings we believe will be realized.

(4) 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 quarters ended March 31:

Investment	Pre-tax Gain (Loss) (In millions)
2005	
Asia investments impairment	$ (82)
Gain on sale of PPN	22
Gain on sale of Enterprise	183
Other	(4)
	$ 119
2004	
Milford power facility	$ (2)
Other	(17)
	$ (19)

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 quarters ended March 31:

	MCV	Other Investments (in millions)	Total
2005			
Operating results data			
Revenues	$65	$283	$348
Operating expenses	(35)	176	141
Income from continuing operations	92	67	159
Net income[(1)]	92	67	159
2004			
Operating results data			
Revenues	$70	$514	$584
Operating expenses	53	332	385
Income from continuing operations	5	107	112
Net income[(1)]	5	104	109

(1) Includes net income of $4 million and $14 million for the quarters ended March 31, 2005 and 2004, related to our proportionate share of affiliates in which we hold a greater than 50 percent interest.

We received distributions and dividends from our investments of $83 million and $96 million for each of the quarters ended March 31, 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 quarters ended March 31:

	2005	2004
	(In millions)	
Operating revenue	$49	$58
Cost of sales	4	22
Reimbursement for operating expenses	1	31
Other income	4	5

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 to 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 sales of natural gas and operational services. For the quarter ended March 31, 2004 revenues received from GulfTerra amounted to $10 million, expenses paid to GulfTerra were $29 million and reimbursements from GulfTerra were $22 million.

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 $105 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. In 2003, an economic crisis developed in the Dominican Republic 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 have been delinquent in their payments to CEPP and Itabo, and to the other generating facilities in the Dominican Republic since April 2003. The failure to pay generators resulted in the inability of the generators to purchase fuel required to produce electricity resulting in significant energy shortfalls in the country. 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. We are contesting the local court decision. We continue to monitor the economic and regulatory situation in the Dominican Republic and as new information becomes available or future material developments arise, it is possible that impairments of these investments 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 continue to reserve the amounts of the delayed payments based on Berkshire's inability to generate adequate cash flows and we recorded a $1 million charge in the first quarter of 2005 related to this agreement. We continue to supply fuel to the plant under the fuel supply agreement and we had a receivable from Berkshire of approximately $7 million as of March 31, 2005, which we collected in May 2005. We may continue to record losses on future fuel deliveries 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 11.

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.

In mid 2004, we discontinued our Canadian and certain other international natural gas and oil production operations. Our results for all periods reflect these operations as discontinued.

Overview

Since the beginning of 2005, we have completed the following activities in connection with the ongoing execution of our strategic plan, an update of which was provided in March 2005:

- Our pipeline segment made further progress on its plans, by reaching a tentative settlement on a rate case at Southern Natural Gas Company (SNG), recontracting with large customers on the SNG and EPNG systems, and completing the Cheyenne Plains Pipeline project;
- Our production segment continued to make progress on its turnaround and the stabilization of its production rates through the completion of three strategic acquisitions of natural gas and oil properties totalling $271 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 our remaining general and limited partnership interests in Enterprise, interests in Cedar Brakes I and II, interests in a paraxylene plant, interest in a natural gas gathering system and processing facility, and a pipeline facility. Total proceeds from these sales were approximately $722 million; and
- We reduced our net debt to $16.1 billion (debt of $17.8 billion, net of cash of $1.65 billion) as of March 31, 2005, lowering our net debt by $953 million; 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 in April 2005 and will be used 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 quarter ended March 31, 2005, we continued to reduce our overall debt as part of our Long-Range Plan announced in December 2003. Our activity during the quarter ended March 31, 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 and other increases	200
Repayments/retirements of principal	(1,010)
Sales of entities[1]	(546)
Other	(63)
Total debt as of March 31, 2005	$17,777

[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 10.

Our net available liquidity as of March 31, 2005 was $1.8 billion, which consisted of $0.4 billion of availability under our $3 billion credit agreement and $1.4 billion of available cash, which includes $180 million intended for the redemption of CIG's 10% bonds maturing in June 2005. 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 10 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 the $3 billion credit agreement. As of March 31, 2005, our ratio of Debt to Consolidated EBITDA was 4.77 to 1 and our ratio of Consolidated EBITDA to interest expense and dividends was 2.0 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.

Overview of Cash Flow Activities for 2005 Compared to 2004

For the quarters ended March 31, 2005 and 2004, our cash flows are summarized as follows:

	2005	2004
	(In billions)	
Cash Inflows		
Continuing operating activities		
Net income (loss) before discontinued operations	$ 0.1	$(0.1)
Non-cash income adjustments	0.3	0.5
Change in assets and liabilities	(0.3)	0.1
	0.1	0.5
Continuing investing activities		
Net proceeds from the sale of assets and investments	0.6	—
Proceeds from settlement of foreign currency derivatives	0.1	—
Other	0.1	0.1
	0.8	0.1
Continuing financing activities		
Net proceeds from the issuance of long-term debt	0.2	0.1
Proceeds from the issuance of common stock	—	0.1
Contributions from discontinued operations	0.1	0.8
	0.3	1.0
Total cash inflows	$ 1.2	$ 1.6

	2005	2004
	(In billions)	
Cash Outflows		
Continuing investing activities		
Additions to property, plant and equipment	$ 0.4	$ 0.4
Net cash paid for acquisitions	0.2	—
Net payments of restricted cash	—	0.1
	0.6	0.5
Continuing financing activities		
Payments to retire debt and redeem preferred interests	1.0	0.6
Other	0.1	0.1
	1.1	0.7
Total cash outflows	$ 1.7	$ 1.2
Net change in cash	$(0.5)	$ 0.4

Cash From Continuing Operating Activities

Overall, cash generated from our continuing operating activities was $0.1 billion during the first quarter of 2005 versus $0.5 billion during the same period of 2004. The $0.4 billion quarter over quarter decrease in operating cash flow was due to differences in working capital utilization in the two periods. In the first quarter of 2005, we paid $240 million to assign or terminate derivative contracts in connection with the sale of Cedar Brakes I and II and had other working capital uses. In the first quarter of 2004, we experienced a $0.1 billion increase in working capital due to various activities, including a $52 million change in stored gas inventory and $40 million from the settlement of margin calls.

Cash From Continuing Investing Activities

Net cash provided by our continuing investing activities was $0.3 billion for the quarter ended March 31, 2005. Our investing activities consisted of the following (in billions):

Production exploration, development and acquisition expenditures	$(0.4)
Pipeline expansion, maintenance and integrity projects	(0.2)
Reduction of restricted cash	0.1
Settlement of a foreign currency derivative	0.1
Proceeds from the sale of assets and investments	0.6
Total continuing investing activities	$ 0.2

Cash received from the sale of assets and investments was primarily from the sale of our remaining interests in Enterprise. For the remainder of 2005, we expect our total capital expenditures to be approximately $1.3 billion, which includes approximately $0.5 billion for our Production segment and $0.8 billion for our Pipelines segment. 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 redemption of that debt.

Cash From Continuing Financing Activities

Net cash used in our continuing financing activities was $0.8 billion for the quarter ended March 31, 2005. Cash provided from our financing activities included $0.1 billion of cash contributed by our discontinued operations and $0.2 billion from the March 2005 issuance of long-term debt on CIG. Cash used in our financing activities included net repayments of $0.3 billion made to retire third party long-term debt and $0.7 billion that was paid to retire a portion of our Euro denominated debt.

Cash From Discontinued Operations

During the first quarter of 2005, our discontinued operations generated $0.1 billion of cash. This was primarily the result of proceeds received from asset sales.

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 March 31, 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	$ 17	$ 11	$ —	$ —	$ —	$ 28
Liabilities	(520)	(235)	(20)	(13)	—	(788)
Total derivatives designated as hedges	(503)	(224)	(20)	(13)	—	(760)
Assets from power contract restructuring derivatives[1]	20	40	5	—	—	65
Other commodity-based derivatives						
Exchange-traded positions[2]						
Assets	64	225	109	6	—	404
Liabilities	(198)	(2)	—	—	—	(200)
Non-exchange-traded positions						
Assets	637	378	244	128	13	1,400
Liabilities[1]	(483)	(562)	(328)	(161)	(24)	(1,558)
Total other commodity-based derivatives	20	39	25	(27)	(11)	46
Total commodity-based derivatives	$(463)	$(145)	$ 10	$ (40)	$(11)	$ (649)

(1) Includes $11 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 quarter ended March 31, 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 March 31, 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	84	(610)	273	(253)
Change in fair value of contracts	(308)	10	(163)	(461)
Option premiums received, net	—	—	(3)	(3)
Net change in contracts outstanding during the period	(224)	(600)	107	(717)
Fair value of contracts outstanding at March 31, 2005	$(760)	$ 65	$ 46	$(649)

(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 year 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. In mid 2004, we discontinued our Canadian and certain other international natural gas and oil production operations. Our results for all periods reflect these operations as discontinued.

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 quarters ended March 31:

	2005	2004
	(In millions)	
Regulated Business		
Pipelines	$ 412	$ 386
Non-regulated Businesses		
Production	183	204
Marketing and Trading	(185)	(172)
Power	(50)	(139)
Field Services	191	36
Segment EBIT	551	315
Corporate	(90)	27
Consolidated EBIT from continuing operations	461	342
Interest and debt expense	(350)	(423)
Distributions on preferred interests of consolidated subsidiaries	(6)	(6)
Income taxes	3	(10)
Income (loss) from continuing operations	108	(97)
Discontinued operations, net of income taxes	(2)	(109)
Net income (loss)	$ 106	$(206)

Overview of Results of Operations

For the quarter ended March 31, 2005, our consolidated EBIT from continuing operations was $461 million of which $551 million was our segment EBIT. During the quarter, our Pipelines, Production and Field Services segments contributed $786 million of combined EBIT. These positive contributions were partially offset by the EBIT losses of $185 million in our Marketing and Trading segment and $50 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 $412 million, which was generally consistent with our expectations for the period.

Production — Our Production segment generated EBIT of $183 million, which was consistent with 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 $185 million, which was a greater loss than our expectations. The performance was driven primarily by significant mark-to-market losses on our production-related derivatives due to natural gas price increases during the period. Our power contracts also experienced significant losses during the period due to changes in natural gas and power prices.

Power — Our Power segment generated an EBIT loss of $50 million, which was a greater loss than expected and was impacted by significant impairments in our Asian operations during the period and ongoing disputes with Petrobras on our Macae project.

Field Services — Our Field Services segment generated EBIT of $191 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 expect to generate EBIT losses as we continue to pursue the sale of our Asian power plant portfolio and remaining domestic plants. In Brazil, we continue to foresee challenges in our Macae power investment. We have also announced our intent to divest of our other remaining international power projects as market conditions warrant. Finally, we expect our EBIT to decline in our Field Services segment as a result of the completion of sales of a majority of our remaining processing assets.

Our earnings in each period were impacted both favorably and unfavorably by a number of factors affecting our businesses including asset and investment losses in our Power segment of $88 million in 2005 and $242 million in 2004, and a $183 million gain in our Field Services segment in 2005 related to the sale of our remaining interest in Enterprise in January 2005. We also recorded a $59 million charge in our corporate operations related to the Western Energy Settlement during the first quarter of 2005. For a more detailed discussion of these items and other items impacting our financial performance for the quarters ended March 31, 2005 and 2004, see the discussions of the individual segment and other results that follow, as well as Item 1, Financial Statements, Notes 3, 4, 11 and 15.

Regulated Businesses — Pipelines Segment

Our Pipelines segment consists of interstate natural gas transmission, storage, LNG terminalling and related services, primarily in the United States. We face varying degrees of competition in this segment from other pipelines and proposed LNG facilities, as well as from alternative energy sources used to generate electricity, such as hydroelectric power, nuclear, coal and fuel oil. For a further discussion of the business activities of our Pipelines segment, see our 2004 Annual Report on Form 10-K, as amended.

Operating Results

Below are the operating results and analysis of these results for our Pipelines segment for each of the quarters ended March 31:

	2005	2004
	(In millions, except volume amounts)	
Operating revenues	$ 768	$ 721
Operating expenses	(406)	(373)
Operating income	362	348
Other income, net	50	38
EBIT	$ 412	$ 386
Throughput volumes (BBtu/d)	22,586	22,510

The following contributed to our overall EBIT increase of $26 million for the quarter ended March 31, 2005 as compared to the same period in 2004:

	Revenue	Expense	Other	EBIT
	Favorable/(Unfavorable) (In millions)			
Contract modifications/terminations	$ 32	$ —	$ —	$32
Gas not used in operations, processing margins and other natural gas sales	20	(9)	—	11
Favorable resolution in 2004 of a measurement dispute at a processing plant	(10)	—	—	(10)
Mainline expansions	16	(7)	—	9
Higher allocated costs[1]	—	(21)	—	(21)
Equity earnings from our investment in Citrus	—	—	8	8
Other[2]	(11)	4	4	(3)
Total impact on EBIT	$ 47	$ (33)	$ 12	$26

(1) Consists primarily of shared services, benefits and corporate overhead allocations.

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

The following provides further discussion of some of the items listed above as well as an outlook on events that may affect our operations in the future. Our 2005 earnings and capital expenditures outlook remains consistent with our strategic plan update in March 2005.

Contract Modifications/Terminations. Included in this item are (i) the impact of ANR completing a 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 by $29 million in the first quarter of 2005 and (ii) the impact of the termination, in April 2004, of EPNG's restrictions on remarketing expiring capacity contracts resulting in increased revenues of $3 million in 2005 as compared to 2004.

In December 2004, EPNG entered into agreements with SoCal to recontract approximately 750 MMcf/d of capacity on its system with various terms extending from 2009 to 2011. Substantially all of the capacity SoCal currently holds on EPNG's system to serve its core (residential and commercial) markets was recontracted as a result of these new agreements. In accordance with the agreement, SoCal gave notice to EPNG in April 2005 that it would terminate its existing capacity contracts. The CPUC recently dismissed consideration of whether local distribution companies (such as SoCal) are obligated to contract for any of their non-core customers. As a result of these events, EPNG will be required to remarket that portion of capacity formerly held by SoCal used to serve its non-core customers, effective September 2006. We are continuing in our efforts to remarket expiring capacity, including marketing efforts to serve SoCal's non-core customers or to serve new markets. At this time, we are uncertain whether this remaining capacity will be recontracted or at what rates this capacity will ultimately be recontracted.

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 order(s), 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. 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, 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. As of January 31, 2005, our Cheyenne Plains Gas Pipeline was placed in-service. As a result, revenues increased by $11 million and overall EBIT increased by $5 million during the first quarter of 2005 compared to the same period in 2004.

Regulatory and Other Matters. In November 2004, the FERC issued a proposed accounting release that may impact certain costs our interstate pipelines incur related to their pipeline integrity programs. If the release is enacted as written, we would be required to expense certain future pipeline integrity costs instead of capitalizing them as part of our property, plant and equipment. Although we continue to evaluate the impact of this potential accounting release, we currently estimate that if the release is enacted as written, we would be required to expense an additional amount of pipeline integrity expenditures in the range of approximately $25 million to $41 million annually over the next eight years.

Our pipeline systems periodically file for changes in their rates which are subject to the approval by FERC. Changes in rates and other tariff provisions resulting from these regulatory proceedings have the potential to negatively impact our profitability. SNG filed a rate case in August 2004; it has reached a tentative settlement in principle that was filed with the FERC on April 29, 2005. The settlement rates were implemented on an interim basis as of March 1, 2005 with all shippers which elected to be consenting parties under the rate settlement. Based on its provisions as currently proposed, we do not expect the settlement to have a material impact on our future costs or EBIT at SNG. The settlement should also have the effect of extending the average contract terms on SNG to seven years. For a further discussion of our current and upcoming rate proceedings, refer to our 2004 Annual Report on Form 10-K, as amended.

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.

ANR has previously filed claims with a bankruptcy court to recover damages from USGen New England, Inc. (USGen) related to two rejected transportation agreements. In April 2005, ANR and USGen signed a Stipulation and Consent Order (Order) with USGen, which provides that ANR will receive approximately $14 million, plus interest on its claims. The Order was approved by the bankruptcy court.

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 locate and develop economic natural gas and oil reserves, extract those reserves with minimal production costs, sell the products at attractive prices, and 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, supplemented by acquisition activities with low risk development opportunities that provide operating synergies with our existing operations.

Operational Factors Affecting the Quarter Ended March 31, 2005

During the first quarter of 2005, our Production segment continued to benefit from a strong commodity price environment and our production volumes were relatively stable from the third and fourth quarters of 2004. However, our production volumes were lower than in the quarter ended March 31, 2004, due to normal production declines and lower capital spending programs over the last several years, combined with limited drilling success. Specifically, during the quarter ended March 31, 2005, we experienced:

- *Higher realized prices.* Realized natural gas prices, which include the impact of our hedges, increased 12 percent and oil, condensate and natural gas liquids (NGL) prices increased 40 percent compared to 2004.
- *Average daily production of 766 MMcfe/d (excluding discontinued operations of 5 MMcfe/d).* Our production remained relatively stable from the third and fourth quarters of 2004 to the first quarter of 2005 for the Onshore and offshore Gulf of Mexico regions while the Texas Gulf Coast region experienced a decline due to normal production declines and mechanical well failures. Average daily production volumes in the first quarter of 2005 benefited from the acquisitions, discussed below, by 26 MMcfe/d. Operations in Brazil continue to produce at an average of approximately 59 MMcfe/d. However, when compared to the first quarter of 2004, our first quarter 2005 total equivalent production declined 13 Bcfe, or 16 percent, due to production declines in the Texas Gulf Coast and offshore Gulf of Mexico regions.
- *Capital expenditures of $425 million.* Our first quarter capital expenditures 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 current production. 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.
- *Drilling Results.* In the first quarter of 2005, we announced a deep shelf discovery at West Cameron Block 75 in the Gulf of Mexico. We tested the discovery and anticipate deliverability of approximately 40 Mcfe/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 this discovery.

Outlook for remainder of 2005

For the remainder of 2005, we anticipate:

- A total capital expenditures budget of approximately $475 to $500 million.
- Daily production volumes for the year to average in excess of 800 MMcfe/d.
- Cash operating costs to be between $1.25/MMcfe and $1.40/MMcfe 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 $2.04/Mcfe in the second quarter of 2005 as compared to $1.97/Mcfe in the first quarter of 2005, due to higher finding and development costs and the costs of acquired reserves.

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 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 discussed above in the first quarter 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 March 31, 2005, the fair value of these positions that is deferred in accumulated other comprehensive income is a loss of $313 million. The income impact of the settlement of these derivative commodity instruments will be substantially offset by the impact of a corresponding change in the price to be received when the hedged natural gas production is sold.

Operating Results

Below are the operating results and analysis of these results for the quarters ended March 31:

	2005	2004
	(In millions)	
Operating Revenues:		
Natural gas	$ 353	$ 368
Oil, condensate and NGL	85	77
Other	1	1
Total operating revenues	439	446
Transportation and net product costs	(13)	(14)
Total operating margin	426	432
Depreciation, depletion and amortization	(146)	(140)
Production costs[1]	(55)	(42)
Restructuring charges	—	(9)
General and administrative expenses	(41)	(36)
Taxes, other than production and income	(4)	(2)
Total operating expenses[2]	(246)	(229)
Operating income	180	203
Other income	3	1
EBIT	$ 183	$ 204

	2005	Percent Variance	2004
Volumes, prices and costs per unit:			
Natural gas			
Volumes (MMcf)	56,158	(15)%	65,699
Average realized prices, including hedges ($/Mcf)[3][4]	$ 6.28	12%	$ 5.61
Average realized prices, excluding hedges ($/Mcf)[3]	$ 5.71	—%	$ 5.69
Average transportation costs($/Mcf)	$ 0.18	20%	$ 0.15
Oil, condensate and NGL			
Volumes (MBbls)	2,136	(21)%	2,710
Average realized prices, including hedges ($/Bbl)[3]	$ 39.86	40%	$ 28.54
Average realized prices, excluding hedges ($/Bbl)[3]	$ 40.20	41%	$ 28.53
Average transportation costs ($/Bbl)	$ 0.75	(39)%	$ 1.22
Total equivalent volumes (MMcfe)	68,976	(16)%	81,958
Production costs ($/Mcfe)			
Average lease operating costs	$ 0.61	24%	$ 0.49
Average production taxes	0.19	533%	0.03
Total production cost[1]	$ 0.80	54%	$ 0.52
Average general and administrative expenses ($/Mcfe)	$ 0.59	34%	$ 0.44
Unit of production depletion cost ($/Mcfe)	$ 2.00	27%	$ 1.58

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

(2) Transportation costs are included in operating expenses on our consolidated statements of income.

(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 Ended March 31, 2005 Compared to Quarter Ended March 31, 2004

Our EBIT for the first quarter of 2005 decreased $21 million as compared to the first quarter of 2004. The table below lists the significant variances in our operating results in the first quarter of 2005 as compared to the first quarter of 2004:

	Variance			
	Operating Revenue	Operating Expense	Other(1)	EBIT Impact
	Favorable/(Unfavorable) (In millions)			
Natural Gas Revenue				
Higher prices in 2005	$ 2	$ —	$ —	$ 2
Lower volumes in 2005	(54)	—	—	(54)
Impact from hedge program in 2005 versus 2004	37	—	—	37
Oil, Condensate, and NGL Revenue				
Higher prices in 2005	25	—	—	25
Lower volumes in 2005	(16)	—	—	(16)
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	—	21	—	21
Production Costs				
Higher lease operating costs in 2005	—	(2)	—	(2)
Higher production taxes in 2005	—	(11)	—	(11)
Other				
Higher general and administrative costs in 2005	—	(5)	—	(5)
Other	—	9	3	12
Total variances	$ (7)	$(17)	$ 3	$(21)

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

Operating Revenues. In the first quarter of 2005, we experienced a significant decrease in production volumes versus the same period in 2004. 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, combined with limited drilling success. In addition, the Texas Gulf Coast region was impacted by mechanical well failures. These declines were offset slightly by higher production in the onshore region. We also had increased natural gas and oil production in Brazil as a result of our acquisition of the remaining interests in, and consolidation of, UnoPaso in July 2004. In addition, our recent domestic acquisitions previously mentioned helped to offset some of our production declines. Offsetting the impact of these overall production declines were higher average realized prices on natural gas and oil, condensate and NGL and a favorable impact from our hedging program. Our hedging gains were $31 million in 2005 as compared to $5 million of hedging losses in 2004.

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.

Production costs. In the first quarter of 2005, we experienced higher gross workover costs due to the implementation of programs in the second half of 2004 to improve production in the offshore Gulf of Mexico and Texas Gulf Coast regions. 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 and higher production costs previously discussed above.

Other. Higher legal expenses, higher benefit costs (primarily associated with pension expense) and reduced capitalized costs, caused our general and administrative expenses to increase in 2005 when compared to the same period 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 related to employee severance expenses of $9 million recorded in the first quarter of 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. Although we currently do not anticipate that we will liquidate all of the transactions in our historical trading portfolio, 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.

Operating Results

Below are the overall operating results and analysis of these results for our Marketing and Trading segment for the quarters ended March 31:

	2005	2004
	(In millions)	
Overall EBIT:		
Gross margin[1]	$(175)	$(159)
Operating expenses	11	16
Operating loss	(186)	(175)
Other income	1	3
EBIT	$(185)	$(172)
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	$ —	$(156)
Changes in fair value on production-related contracts	(106)	—
Changes in fair value on other natural gas positions	26	(5)
Total production-related and other natural gas derivatives	(80)	(161)
Transportation-related contracts		
Demand charges	(39)	(39)
Settlements	27	21
Total transportation-related contracts	(12)	(18)
Total gross margin — natural gas contracts	(92)	(179)
Power contracts		
Changes in fair value on Cordova tolling agreement	(33)	15
Changes in fair value on other power derivatives	(50)	5
Total gross margin — power contracts	(83)	20
Total gross margin	$(175)	$(159)

(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 ended March 31, 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 in the first quarter of 2004 were a result of increases in natural gas prices relative to the fixed prices in these contracts. These losses were historically included in our financial results; however, following their designation as accounting hedges in the fourth quarter of 2004, future income impacts of these contracts are reflected in our Production segment.

- *Other production-related derivatives.* In the fourth quarter of 2004, we entered into option contracts to provide price protection on a portion of our Production segment's anticipated natural gas production in 2005 and 2006. These contracts, which are not accounting hedges and are marked to market in our results each period, will allow El Paso to achieve a floor price of $6.00 per MMBtu on 54 TBtu of our future natural gas production in 2005 and 120 TBtu in 2006. Due to increasing natural gas prices, the fair value of these contracts decreased by $92 million during the first quarter of 2005.

  In the first quarter of 2005, we entered into additional option contracts to provide price protection on a portion of our Production segment's anticipated natural gas production in 2006 and 2007. We received a net premium of approximately $3 million for these options that provide El Paso with a floor price of $6.00 per MMBtu on 30 TBtu of our natural gas production in 2007 and cap us at a ceiling price of $9.50 per MMBtu on 60 TBtu of our natural gas production in 2006. Due to increasing natural gas prices, the fair value of these contracts decreased by $12 million during the first quarter of 2005.

  The fair value of all our option contracts as of March 31, 2005, was $13 million. Should the price of natural gas remain between $6.00 and $9.50 per MMBtu, these contracts will remain unexercised and will expire without any value.

  Also, the first quarter of 2005, our Production segment acquired the interest held by one of its partners under a net profits interest agreement. In March 2005, we entered into several derivative contracts that, on a net basis, obligate us to sell natural gas at fixed prices related to 4 TBtu of the anticipated 2005 and 2006 natural gas production from this acquisition. Due to increasing natural gas prices, the fair value of these swaps decreased by $2 million during the first quarter of 2005.

- *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 several 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 $90 million as of March 31, 2005, net of related hedges.

Transportation-related contracts

- Demand charges paid on our Alliance pipeline capacity contract were $16 million in the first quarter of 2005 and $15 million in the first quarter of 2004. Our ability to use our Alliance pipeline capacity contract was relatively consistent during these periods, allowing us to recover approximately 65 percent of our demand charges in the first quarter of 2005 and 69 percent in the first quarter 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 $23 million in the first quarter of 2005 and $24 million in the first quarter of 2004. Our ability to use the capacity under these contracts improved in 2005 due to increased price differentials between the receipt and delivery points for the contracts. This allowed us to recover approximately 67 percent of the demand charges on our Texas Intrastate contracts and 73 percent on our other transportation contracts during the first quarter of 2005, compared to only 25 percent and 54 percent during the same period in 2004.

Power Contracts

Cordova tolling agreement

Our Cordova agreement is sensitive to changes in forecasted natural gas and power prices. In 2004, forecasted power prices increased relative to natural gas prices, resulting in an increase in the fair value of this contract. In 2005, 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 $23 million in the first quarter of 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 $7 million during the first quarter of 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 decreased in fair value by $90 million in first quarter 2005 and $55 million in first quarter 2004. The decreases in fair value resulted from increasing power prices related to this obligation during the quarters ended March 31, 2005 and 2004.

- During each of the quarters ended March 31, 2005 and 2004, we were required to purchase power under our remaining power contracts, which include those that are used to manage the risk associated with our obligations to supply power. Due to increasing power prices, the fair value of these contracts increased by $47 million during the quarter ended March 31, 2005 and by $83 million during the quarter ended March 31, 2004.

Operating Expenses

Operating expenses were relatively consistent for the quarters ended March 31, 2005 and March 31, 2004. We recorded a $1 million loss in the first quarter of 2005 related to additional payments delayed by Berkshire under their fuel supply agreement. Berkshire is no longer able to delay any future payments under this agreement. We may continue to record losses on anticipated future deliveries based on Berkshire's inability to generate adequate cash flows and uncertainty surrounding their negotiations with their lenders. See Item 1, Financial Statements, Note 16 for additional information on this fuel supply agreement.

Non-regulated Business — Power Segment

As of March 31, 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 or announced the sale of substantially all of these domestic businesses. Our ongoing focus within the power segment will be to maximize the value of our assets in Brazil. We have designated our other international power operations as non-core activities, and we expect to exit these activities in the future as market conditions warrant.

Significant factors impacting or occurring in the first quarter 2005 include:

- *Brazil.* Our Macae project in Brazil has a contract that requires Petrobras to make minimum revenue payments until August 2007. Petrobras did not pay amounts due under the contract for December 2004 and the first quarter of 2005 and has filed a lawsuit and initiated arbitration proceedings related to that obligation. For a further discussion of this matter, see Item 1, Financial Statements, Note 11. The future financial performance of the Macae plant will be affected by the outcome of this dispute, the timing of that outcome, and by regional changes in the Brazilian power markets.

- *Asia.* During the first quarter 2005, we engaged an investment banker to facilitate the sale of our Asian power assets. In April 2005, the Board of Directors approved the sale of these assets and we expect that the sale of these assets will be substantially completed by the end of 2005.

- *Other International Power.* In April 2005, we completed the sale of our Enfield power facility in England. We have previously announced that we are considering the sale of our other remaining international assets. As of March 31, 2005, we have not begun to actively market these remaining assets. As this process progresses we will continue to assess the value of these assets which may result in impairments that may be significant.

- *Domestic Power Contract Restructurings.* On March 24, 2005, a bankruptcy court entered an order resolving Mohawk River Funding III's (MRF III) bankruptcy claims with USGen New England by allowing MRF III a general unsecured claim in the amount of $168 million, including interest. Previously, USGen had terminated a power purchase agreement with MRF III as a result of filing for bankruptcy, upon which MRF III filed a bankruptcy claim of $177 million. USGen's filed plan of liquidation is set for a confirmation hearing on May 12, 2005 and provides for a one hundred percent payout to general unsecured creditors. Distributions to creditors are anticipated no later than the third quarter of 2005 if the plan is confirmed. To the extent we receive a full payout of our claim, we would recognize gains in our Power segment and our Marketing and Trading segment because a portion of these receivables had been previously written off.

Operating Results

Below are the overall operating results and analysis of activities within our Power segment for the quarters ended March 31:

	2005	2004
	(In millions)	
Overall EBIT:		
Gross margin[1]	$ 59	$ 160
Operating expenses		
Loss on long-lived assets	(27)	(224)
Other operating expenses	(70)	(124)
Operating loss	(38)	(188)
Earnings from unconsolidated affiliates		
Impairments, net of gains on sale	(61)	(18)
Equity in earnings	33	47
Other income	16	20
EBIT	$ (50)	$(139)

[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.

	2005	2004
	(In millions)	
EBIT by Area:		
Brazil		
Earnings from consolidated and unconsolidated plant operations	$ 14	$ 57
Manaus and Rio Negro impairment	—	(135)
Asia		
Earnings from consolidated and unconsolidated plant operations	10	16
Gain on sale of PPN power plant	22	—
Impairments	(96)	—
Other	—	11
Other International Power		
Earnings from consolidated and unconsolidated plant operations	10	7
Impairments	(1)	—
Other	—	(10)
MCV		
Earnings from plant operations	1	5
Domestic assets sold or expected to be sold in 2005		
Earnings from consolidated and unconsolidated operations	—	7
Impairments and write-offs	—	(11)
Domestic Power Contract Restructurings		
Impairments, net of gains on asset sales	—	(96)
Change in fair value of contracts	10	19
Other	1	3
Power turbine impairments	(15)	—
Other(1)	(6)	(12)
EBIT	$(50)	$(139)

(1) 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.

Brazil. Our earnings from operations from Brazil decreased primarily due to a $40 million decrease in earnings from our Macae plant. During the first quarter of 2005, we did not recognize approximately $45 million of revenues due on our contract with Petrobras based on Petrobras' non-payment of amounts due as a result of our ongoing dispute with Petrobras. Also contributing to the decrease was a $5 million decrease in the earnings from our Manaus and Rio Negro plants that resulted from the acceleration of the depreciation of the underlying plants, due to their expected ownership transfer to Manaus Energia in 2008. During the first quarter of 2004, we recorded an impairment of the Manaus and Rio Negro power plants based on the status of our negotiations to extend the contracts, which was negatively impacted by changes in the Brazilian political environment.

Asia. During the first quarter of 2005, we further impaired our Asian power assets in connection with our decision to pursue the sale of these assets and the receipt of additional information on the sales value of certain of these assets. As the sales process continues, we will continue to update the fair value of our Asian assets. Depending on the final outcome of this process, we could recognize significant gains on some assets and further losses on other assets in the portfolio. Certain of our equity investees in Asia, on which we have previously recorded impairments, reported earnings of $11 million during the quarter ended March 31, 2005. We determined that these earnings did not increase the fair value of these equity investments and could not be realized in the future. We did not recognize our proportionate share of these earnings based on this evaluation. 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.

Other International Power. Earnings from our other international plant operations increased in the first quarter of 2005 as compared to the same period of 2004 primarily due to improved economic conditions in the Dominican Republic. We also recorded an impairment of our interest in a power plant in England in the first quarter of 2005 in connection with the sale of that investment in April 2005.

MCV. In December 2004, we impaired our investment in MCV based on a decline in the value of the investment due to increased fuel costs. MCV reported earnings during the first quarter of 2005, of which our proportionate share, after eliminations, was $72 million. A significant portion of these earnings related to mark-to-market gains recorded by MCV on their unaffiliated fuel supply contracts. We determined that these earnings did not increase the fair value of our equity investment and could not be realized in the future. As a result, we decreased our proportionate share of MCV's earnings by $71 million to reflect the amount of earnings that we believe could be realized. We will continue to assess our ability to recover our investment in MCV and its related operations in the future.

Domestic assets sold or to be sold in 2005. During the quarter ended March 31, 2004, we recorded impairments of approximately $11 million of our held for sale merchant and contracted plants based on their expected sales proceeds.

Domestic Power Contract Restructurings. 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. During the quarter ended March 31, 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.

Power Turbine Impairments. During the first quarter of 2005, we recorded an impairment of $15 million to our power turbines based on the receipt of further information about their fair value.

Non-regulated Business — Field Services Segment

Our Field Services segment conducts our remaining midstream activities, which primarily include gathering and processing assets in south Louisiana. 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. We currently expect to sell many of our remaining Field Services assets, except those that may be strategic to other parts of our business.

Below are the operating results and analysis of the results for our Field Services segment for the quarters ended March 31:

	2005	2004
	(In millions, except volumes and prices)	
Gathering and processing margins[1]	$ 20	$ 45
Operating expenses		
Loss on long-lived assets	(1)	(2)
Other operating expenses	(8)	(33)
Operating income	11	10
Other income (expense)		
Earnings from unconsolidated affiliates	180	37
Other	—	(11)
EBIT	$ 191	$ 36

	2005	2004
	(In millions, except volumes and prices)	
Volumes and Prices:		
Processing		
Volumes (BBtu/d)	1,609	3,243
Prices ($/MMBtu)	$ 0.13	$ 0.13
Gathering		
Volumes (BBtu/d)	43	186
Prices ($/MMBtu)	$ 0.03	$ 0.12

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

Below is a summary of significant factors and related discussions affecting EBIT for the quarters ended March 31:

	2005	2004
	(In millions)	
Gathering and Processing Activities		
Retained Assets		
Gathering and processing margins	$ 19	$ 18
Operating expenses	(8)	(26)
Equity investment impairments	(3)	—
Equity earnings	—	3
	8	(5)
Indian Springs[1]		
Gathering and processing margins	1	4
Operating expenses	—	(2)
Loss on sale	(1)	—
South Texas assets[1]		
Gathering and processing margins	—	23
Operating expenses	—	(5)
Impairment	—	(2)
Enterprise Related Items		
Sale of assets/interest in Enterprise		
Gain on sale of GP interest and common units	183	—
Minority interest	—	(11)
GulfTerra equity earnings[1]	—	34
	183	41
EBIT	$191	$ 36

(1) Sold to Enterprise during 2004 and 2005.

Gathering and Processing Activities. During the quarter ended March 31, 2005, we experienced a decrease in our operation and maintenance expenses as compared to the same period in 2004 primarily as a result of asset sales. During the first quarter of 2005, we fully impaired our investment in two pipeline systems based on our expectation that our investee would abandon these pipelines in the near future.

For a discussion of our historical ownership interests in Enterprise and activities with the partnership, see Item 1, Financial Statements, Note 16. For a further discussion of the 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 ended March 31, 2005, EBIT in our corporate operations was lower than the same period in 2004 due to the following:

	Favorable (unfavorable) in EBIT for quarter ended March 31, 2005 compared to 2004
	(In millions)
Western Energy Settlement charge in 2005[1]	$ (59)
Losses on early extinguishment of debt in 2005	(29)
Change in litigation, insurance and other reserves	(15)
Other	(14)
Total decrease in EBIT	$(117)

[1] See Item 1, Financial Statements, Note 9 for a further discussion of this charge.

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. Also, in 2005, we increased our insurance reserves by approximately $18 million, which related to additional potential premiums from our mutual insurance companies.

As discussed in Item I, Financial Statements, Note 3, we accrued $80 million in 2004 related to the consolidation of our Houston-based operations. Our estimated costs were based on a discounted liability, which includes estimates of future sublease rentals. Our earnings in future periods could be impacted by the extent to which actual sublease rentals differ from our estimates and the timing of the occurrence of certain other events. We will incur additional charges as we vacate the remaining space that we lease, and estimate that the total additional accrual and charge could be $10 million to $20 million. In addition, we are currently reviewing our options regarding early release from the lease obligation, which if completed in its current form, will result in a further increase in amounts we have accrued. Based on current negotiations, the termination and early release of our obligations could result in additional accruals of $15 million to $20 million.

Interest and Debt Expense

Interest and debt expense for the quarter ended March 31, 2005, was $73 million lower than the same periods in 2004. Below is an analysis of our interest expense for the quarters ended March 31:

	2005	2004
	(In millions)	
Long-term debt, including current maturities	$344	$405
Other	6	18
Total interest and debt expense	$350	$423

During the first quarter of 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 10 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 quarters ended March 31 were as follows:

	2005	2004
	(In millions, except for rates)	
Income taxes	$(3)	$10
Effective tax rate	(3)%	(11)%

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

- state income taxes, net of federal income tax effects;
- a reduction of $30 million of our liabilities for tax contingencies as a result of an IRS settlement on the 1995 to 1997 Coastal Corporation income tax returns and expiration of a tax indemnity claim;
- state tax adjustments to reflect income tax returns as filed;
- foreign income taxed at different rates, including impairments/sales of certain of our foreign investments;
- earnings/losses from unconsolidated affiliates where we anticipate receiving dividends; and
- non-deductible dividends on the preferred stock of subsidiaries.

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.

In 2004, Congress proposed, but failed to enact, legislation which would disallow deductions for certain settlements made to or on behalf of governmental entities. It is possible Congress will reintroduce similar legislation in 2005. If enacted, this tax legislation could impact the deductibility of the Western Energy Settlement resulting in a write-off of some or all of the associated tax benefits. In such event, our tax expense would increase. Our total tax benefits related to the Western Energy Settlement were approximately $400 million as of March 31, 2005.

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 not issued final guidelines for applying the repatriation provisions of the American Jobs Creation Act. We are currently evaluating whether we will repatriate any foreign earnings under the American Jobs Creation Act, and are evaluating the other provisions of this legislation, which may impact our taxes in the future.

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, we currently expect to utilize proceeds from the sale of certain of our Asian power investments within the U.S. and have deferred tax liabilities of $32 million and $39 million related to these investments as of March 31, 2005 and December 31, 2004. We also have deferred tax assets of $14 million and $6 million related to certain of our Asian power investments as of March 31, 2005 and December 31, 2004. However, we have not recorded deferred tax assets on those investments where uncertainty exists as to the manner, timing and ultimate approval of the sales.

For a further discussion of our effective tax rates, see Item 1, Financial Statements, Note 5.

Commitments and Contingencies

See Item 1, Financial Statements, Note 11, 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 $30 million as of March 31, 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 March 31, 2005 and December 31, 2004, we had $65 million and $665 million of third party long-term restructured power derivative contracts. In March 2005, we sold our 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 the first quarter of 2005 related to these material weaknesses are described below.

Evaluation of Disclosure Controls and Procedures

As of March 31, 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 (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")). This evaluation considered the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in the SEC reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms, and that such information is accumulated and communicated to our management, including the CEO and CFO, as appropriate, to allow timely discussion regarding required financial disclosure.

Based on the results of this evaluation, our CEO and CFO concluded that as a result of the material weaknesses discussed above, our disclosure controls and procedures were not effective as of March 31, 2005. Because of these material weaknesses, we performed additional procedures to ensure that our financial statements as of and for the quarter ended March 31, 2005, were fairly presented in all material respects in accordance with generally accepted accounting principles.

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 information technology financial system to monitor unauthorized password changes;
- Developed a segregation of duties matrix for our primary information technology 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.

We have identified other remedial actions to improve our internal control over financial reporting that are in the process of being implemented. In addition, we are continuing to evaluate the ongoing effectiveness and sustainability of the changes we have made in our internal control, and, as a result of our ongoing evaluation, we may identify additional changes to improve our internal control over financial reporting.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Note 11, 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.

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

None.

Item 5. Other Information

None.

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	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).
10.HH	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 April 15, 2005).
10.II	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).
*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: May 9, 2005

/s/ D. DWIGHT SCOTT

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

Date: May 9, 2005

/s/ JEFFREY I. BEASON

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