EL PASO CORP/DE
Form 10-Q
May 05, 2006

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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, 2006
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 þ No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filer þ Accelerated filer o Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No þ

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 3, 2006: 660,021,504

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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
Bcfe	= billion cubic feet of natural gas equivalents	MMcfe	= million cubic feet of natural gas equivalents
LNG	= liquefied natural gas	MW	= megawatt
MBbls	= thousand barrels	NGL	= natural gas liquids
Mcf	= thousand cubic feet	TBtu	= trillion British thermal units

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

When we refer to us , we , our , ours , the company or El Paso , we are describing El Paso Corporation and/or subsidiaries.

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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, 2006	Quarter Ended March 31, 2005
Operating revenues	$ 1,531	$ 1,088
Operating expenses		
Cost of products and services	61	94
Operation and maintenance	334	411
Depreciation, depletion and amortization	272	269
Loss on long-lived assets		7
Taxes, other than income taxes	64	65
	731	846
Operating income	800	242
Earnings from unconsolidated affiliates	45	190
Other income, net	43	31
Interest and debt expense	(348)	(343)
Preferred interests of consolidated subsidiaries		(6)
Income before income taxes	540	114
Income taxes	165	1
Income from continuing operations	375	113
Discontinued operations, net of income taxes	(19)	(7)
Net income	356	106
Preferred stock dividends	10	
Net income available to common stockholders	$ 346	$ 106
Earnings per common share		
Basic		
Income from continuing operations	$ 0.56	$ 0.18
Discontinued operations, net of income taxes	(0.03)	(0.01)
Net income	$ 0.53	$ 0.17
Diluted		

Income from continuing operations	$ 0.52	$ 0.18
Discontinued operations, net of income taxes	(0.03)	(0.01)
Net income	$ 0.49	$ 0.17
Weighted average common shares outstanding		
Basic	656	640
Diluted	724	642
Dividends declared per common share	$ 0.04	$ 0.04

See accompanying notes.

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

	March 31, 2006	December 31, 2005
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,779	$ 2,132
Accounts and notes receivable		
Customers, net of allowance of $51 in 2006 and $67 in 2005	829	1,115
Affiliates	62	58
Other	149	141
Assets from price risk management activities	302	641
Margin and other deposits held by others	875	1,124
Assets related to discontinued operations	637	230
Deferred income taxes	250	396
Other	351	348
Total current assets	5,234	6,185
Property, plant and equipment, at cost		
Pipelines	20,267	19,965
Natural gas and oil properties, at full cost	15,980	15,738
Other	629	651
	36,876	36,354
Less accumulated depreciation, depletion and amortization	17,782	17,567
Total property, plant and equipment, net	19,094	18,787
Other assets		
Investments in unconsolidated affiliates	2,414	2,473
Assets from price risk management activities	1,120	1,368
Goodwill and other intangible assets, net	413	413
Other	2,326	2,612
	6,273	6,866
Total assets	$ 30,601	$ 31,838

See accompanying notes.

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EL PASO CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS (Continued)
(In millions, except share amounts)
(Unaudited)

	March 31, 2006	December 31, 2005
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 570	$ 864
Affiliates	1	10
Other	582	540
Short-term financing obligations, including current maturities	848	986
Liabilities from price risk management activities	655	1,418
Liabilities related to discontinued operations	499	420
Margin deposits held by us	845	497
Accrued interest	308	290
Other	673	687
Total current liabilities	4,981	5,712
Long-term financing obligations, less current maturities	16,232	17,023
Other		
Liabilities from price risk management activities	1,659	2,005
Deferred income taxes	1,529	1,405
Other	2,286	2,273
	5,474	5,683
Commitments and contingencies		
Securities of subsidiaries	32	31
Stockholders equity		
Preferred stock, par value $0.01 per share; authorized 50,000,000 shares; issued 750,000, 4.99% convertible perpetual shares in 2005; stated at liquidation value	750	750
Common stock, par value $3 per share; authorized 1,500,000,000 shares; issued 667,150,185 shares in 2006 and 667,082,043 shares in 2005	2,001	2,001
Additional paid-in capital	4,547	4,592
Accumulated deficit	(3,059)	(3,415)
Accumulated other comprehensive loss	(163)	(332)
Treasury stock (at cost); 7,920,105 shares in 2006 and 7,620,272 shares in 2005	(194)	(190)
Unamortized compensation		(17)
Total stockholders equity	3,882	3,389

Total liabilities and stockholders equity	$	30,601	$	31,838

See accompanying notes.

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EL PASO CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)
(Unaudited)

	Quarter Ended March 31, 2006	Quarter Ended March 31, 2005
Cash flows from operating activities		
Net income	$ 356	$ 106
Loss from discontinued operations, net of income taxes	(19)	(7)
Net income from continuing operations	375	113
Adjustments to reconcile net income to net cash from operating activities		
Depreciation, depletion and amortization	272	269
Loss on long-lived assets		7
Earnings (losses) from unconsolidated affiliates, adjusted for cash distributions	10	(107)
Deferred income taxes	160	48
Other non-cash items	22	28
Change in margin and other deposits	597	108
Other asset and liability changes	(487)	(410)
Cash provided by continuing operations	949	56
Cash provided by (used in) discontinued operations	2	(5)
Net cash provided by operating activities	951	51
Cash flows from investing activities		
Capital expenditures	(401)	(388)
Net proceeds from the sale of assets and investments	59	633
Proceeds from settlement of a foreign currency derivative		131
Cash paid for acquisitions, net of cash acquired		(173)
Other	22	30
Cash provided by (used in) continuing operations	(320)	233
Cash provided by discontinued operations		122
Net cash provided by (used in) investing activities	(320)	355
Cash flows from financing activities		
Payments to retire long-term debt and other financing obligations	(948)	(996)
Net proceeds from the issuance of long-term debt and other financing obligations		197
Dividends paid	(36)	(26)
Contributions from discontinued operations	2	73
Other		(3)
Cash used in continuing operations	(982)	(755)

Cash used in discontinued operations	(2)	(117)
Net cash used in financing activities	(984)	(872)
Change in cash and cash equivalents	(353)	(466)
Cash and cash equivalents		
Beginning of period	2,132	2,117
End of period	$ 1,779	$ 1,651

See accompanying notes.

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EL PASO CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)
(Unaudited)

	Quarter Ended March 31,	
	2006	**2005**
Net income	$ 356	$ 106
Foreign currency translation adjustments (net of income taxes of less than $1 in 2006 and $1 in 2005)	3	11
Unrealized net gains (losses) from cash flow hedging activity		
Unrealized mark-to-market gains (losses) arising during period (net of income taxes of $76 in 2006 and $102 in 2005)	131	(189)
Reclassification adjustments for changes in initial value to the settlement date (net of income taxes of $11 in 2006 and $13 in 2005)	20	(21)
Change in unrealized gains on available for sale securities (net of income tax of $8 in 2006)	15	
Other comprehensive income (loss)	169	(199)
Comprehensive income (loss)	$ 525	$ (93)

See accompanying notes.

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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 accounting principles generally accepted in the United States of America. You should read this Quarterly Report on Form 10-Q along with our 2005 Annual Report on Form 10-K, which includes a summary of our significant accounting policies and other disclosures. The financial statements as of March 31, 2006, and for the quarters ended March 31, 2006 and 2005, are unaudited. We derived the balance sheet as of December 31, 2005, from the audited balance sheet included in our 2005 Annual Report on Form 10-K. In our opinion, we have made all adjustments which are of a normal, recurring nature to fairly present our interim period results. Due to the seasonal nature of our businesses, information for interim periods may not be indicative of our results of operations for the entire year. Our results for all periods presented reflect our south Louisiana gathering and processing assets, which were part of our historical Field Services segment, and our Macae power facility in Brazil and certain other international power operations as discontinued operations. Additionally, our financial statements for prior periods include reclassifications that were made to conform to the current period presentation. Those reclassifications did not impact our reported net income or stockholders equity.

Significant Accounting Policies

Our significant accounting policies are discussed in our 2005 Annual Report on Form 10-K. The information below provides updating information, disclosure where these policies have changed or required interim disclosures with respect to those policies.

Stock Based Compensation. In December 2004, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 123(R), *Share-Based Payment.* This standard and related interpretations amend previous stock-based compensation guidance and require companies to measure all employee stock-based compensation awards at fair value on the date they are granted to employees and recognize compensation cost in their financial statements over the requisite service period. Effective January 1, 2006, we adopted the provisions of SFAS No. 123(R) for stock based compensation awards granted on or after that date and for unvested awards outstanding at that date using the modified prospective application method. Under this method, prior period results were not restated. Prior to January 1, 2006, we accounted for these plans using the intrinsic value method under the provisions of Accounting Principles Board (APB) No. 25, *Accounting for Stock Issued to Employees,* and its related interpretations and did not record expense on stock options granted at the market value on the date of grant. The adoption of SFAS No. 123(R) did not have a material impact to our financial statements as of and for the quarter ended March 31, 2006. For additional information on the adoption of this standard, see Note 12.

Accounting for Pipeline Integrity Costs. On January 1, 2006, we adopted an accounting release issued by the Federal Energy Regulatory Commission (FERC) that requires us to begin expensing certain costs our interstate pipelines incur related to their pipeline integrity programs. Prior to January 1, 2006, we capitalized these costs as part of our property, plant and equipment. The adoption of this accounting release did not have a material impact to our financial statements as of and for the quarter ended March 31, 2006.

2. Acquisitions

In August 2005, we acquired Medicine Bow Energy Corporation, a privately held energy company, for total cash consideration of $853 million. Medicine Bow owns a 43.1 percent interest in Four Star Oil & Gas

Company, an unconsolidated affiliate. Our proportionate share of the operating results associated with Four Star are reflected as earnings from unconsolidated affiliates in our financial statements.

We reflected Medicine Bow s results of operations in our income statement beginning September 1, 2005. The following summary unaudited pro forma consolidated results of operations for the quarter ended March 31, 2005 reflect the combination of our historical income statements with Medicine Bow, adjusted for certain effects of the acquisition and related funding. These pro forma results are prepared as if the acquisition had occurred as of the beginning of the period presented and are not necessarily indicative of the operating results that would have occurred had the acquisition been consummated at that date, nor are they necessarily indicative of future operating results.

	Quarter Ended March 31, 2005
	(In millions, except per share amounts)
Revenues	$ 1,101
Net income available to common stockholders	112
Basic and diluted net income per share	0.17

3. Divestitures

Sales of Assets and Investments

During the quarters ended March 31, we completed the sale of a number of assets and investments. The following table summarizes the proceeds from these sales:

	2006	2005
	(In millions)	
Pipelines	$	$ 32
Exploration and Production	6	
Power	59	110
Field Services		501
Total continuing[1]	65	643
Discontinued		79
Total	$ 65	$ 722

[1] Proceeds exclude returns of invested capital and cash transferred with the assets sold and include costs incurred in preparing assets for disposal. These items decreased our sales proceeds by $6 million and $10 million for the quarters ended March 31, 2006 and 2005.

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

	2006	2005
Pipelines	None	Facilities located in the southeastern U.S.
Exploration and Production	Miscellaneous offshore natural gas and oil properties	None
Power	Interests in power plants in Hungary, Peru and Bangladesh	Cedar Brakes I and II Interest in a power plant in India 2 domestic power plants
Field Services	N/A	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
Discontinued	None	Interest in Paraxylene facility Methyl tertiary-butyl ether (MTBE) processing facility

In addition to the above asset sales, we have also completed or entered into agreements to sell a number of our power assets for total proceeds of approximately $675 million, including our Macae power facility in Brazil, our interests in our remaining Asian power assets and substantially all of our interests in our Central American power assets. We also signed a letter of intent in the first quarter of 2006 to resolve the arbitration proceedings with COPEL relating to the Araucaria power facility in Brazil and to sell our interest in the facility to COPEL for $190 million. See Note 9 for a further discussion of these matters. Additionally, in April 2006, we completed the sale of certain non-strategic south Texas natural gas and oil properties for $67 million.

Discontinued Operations

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. The following is a description of our discontinued operations.

Macae and Other International Power Operations. In the first quarter of 2006, our Board of Directors approved the sale of our interest in the Macae power facility in Brazil to Petrobras. In conjunction with the sale completed in April 2006, we received $358 million and repaid approximately $229 million of Macae s project debt. During 2005, our Board of Directors approved the sale of our Asian and Central American power asset portfolio, which included our consolidated interests in the Nejapa, CEBU and East Asia Utilities power plants. We expect to complete the sale of these power plants during 2006.

South Louisiana Gathering and Processing Operations. During the second quarter of 2005, our Board of Directors approved the sale of our south Louisiana gathering and processing assets, which were part of our historical Field Services segment. In the fourth quarter of 2005, we completed the sale of these assets.

International Natural Gas and Oil Operations. In 2004 and 2005, we completed the sales of these operations, which consisted of our Canadian and certain other international natural gas and oil production operations.

Petroleum Markets. As of December 31, 2005, the sale of substantially all of these operations had been completed.

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The summarized operating results of our discontinued operations were as follows:

	Macae and Other International Power Operations	South Louisiana Gathering and Processing Operations	International Natural Gas and Oil Production Operations	Petroleum Markets	Total
			(In millions)		
Quarter Ended March 31, 2006					
Revenues	$ 50	$	$	$	$ 50
Costs and expenses	(53)				(53)
Loss on long-lived assets	(12)				(12)
Interest and debt expense	(7)				(7)
Loss before income taxes	$ (22)	$	$	$	(22)
Income taxes					3
Loss from discontinued operations, net of income taxes					$ (19)
Quarter Ended March 31, 2005					
Revenues	$ 54	$ 87	$ 2	$ 44	$ 187
Costs and expenses	(53)	(78)	(1)	(53)	(185)
Gain (loss) on long-lived assets	(14)		(1)	3	(12)
Other income	2			15	17
Interest and debt expense	(7)				(7)
Income (loss) before income taxes	$ (18)	$ 9	$	$ 9	
Income taxes					(7)
Loss from discontinued operations, net of income taxes					$ (7)

Assets and liabilities of discontinued operations primarily relate to our Macae power facility. As of March 31, 2006 and December 31, 2005, we had total assets of approximately $0.6 billion, including net property, plant, and equipment of approximately $0.3 billion and other assets, primarily current restricted cash. As of March 31, 2006 and December 31, 2005, total liabilities were approximately $0.5 billion and $0.4 billion, which included current maturities of long-term debt of approximately $0.2 billion and other liabilities, primarily other accounts payable.

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 quarter ended March 31, 2005, our loss on long-lived assets of $7 million was primarily due to a $15 million impairment recorded by our Power segment to adjust the carrying value of its power turbines to their expected sales price, partially offset by a gain of $7 million recorded by our Pipelines segment on the sale of facilities located in the southeastern United States.

5. Income Taxes

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

	2006	2005
	(In millions, except rates)	
Income taxes	$ 165	$ 1
Effective tax rate	31%	1%

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 2006, our overall effective tax rate on

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continuing operations was different than the statutory rate of 35 percent primarily due to a reduction of our liabilities for tax contingencies as a result of IRS settlements on an El Paso Corporation income tax return, tax refunds, and other items, including (i) state income taxes, net of a federal income tax effect and (ii) earnings/losses from unconsolidated affiliates where we anticipate receiving dividends.

During the first quarter of 2005, our overall effective tax rate on continuing operations was significantly different than the statutory rate of 35 percent primarily due to a reduction in our liabilities for tax contingencies as a result of an IRS settlement on the 1995 to 1997 The Coastal Corporation (now known as El Paso CGP, L.L.C.) 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.

6. Earnings Per Share

We calculated basic and diluted earnings per common share as follows for the quarters ended March 31 (in millions):

	2006		2005	
	Basic	**Diluted**	**Basic**	**Diluted**
Income from continuing operations	$ 375	$ 375	$ 113	$ 113
Convertible preferred stock dividends	(10)			
Interest on trust preferred securities		2		
Income from continuing operations available to common stockholders	365	377	113	113
Discontinued operations	(19)	(19)	(7)	(7)
Net income available to common stockholders	$ 346	$ 358	$ 106	$ 106
Weighted average common shares outstanding	656	656	640	640
Effect of dilutive securities:				
Options and restricted stock		3		2
Convertible preferred stock		57		
Trust preferred securities		8		
Weighted average common shares outstanding and dilutive potential common shares	656	724	640	642
Earnings per common share:				
Income from continuing operations	$ 0.56	$ 0.52	$ 0.18	$ 0.18
Discontinued operations, net of income taxes	(0.03)	(0.03)	(0.01)	(0.01)
Net income	$ 0.53	$ 0.49	$ 0.17	$ 0.17

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 per common share is antidilutive. In 2005, these securities primarily included shares related to employee stock options and restricted stock, trust preferred securities and convertible debentures. For the first quarter of 2006, only convertible debentures were antidilutive.

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, 2006 and December 31, 2005. In the table, derivatives designated as hedges consist of instruments used to hedge our natural gas and oil production. Other commodity-based derivative contracts

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relate to derivative contracts not designated as hedges, such as options, swaps and other natural gas and power purchase and supply contracts as well as contracts related to our historical energy trading activities. Finally, interest rate and foreign currency hedging derivatives consist of swaps that are designed to hedge our interest rate and currency risks on long-term debt.

	March 31, 2006	December 31, 2005
	(In millions)	
Net assets (liabilities)		
Derivatives designated as hedges	$ (352)	$ (653)
Other commodity-based derivative contracts	(549)	(763)
Total commodity-based derivatives[1]	(901)	(1,416)
Interest rate and foreign currency derivatives	9	2
Net liabilities from price risk management activities [2]	$ (892)	$ (1,414)

(1) The decrease in the liability during the quarter ended March 31, 2006 is primarily due to changes in natural gas prices.

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

8. Debt, Other Financing Obligations and Other Credit Facilities

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

	March 31, 2006	December 31, 2005
	(In millions)	
Short-term financing obligations, including current maturities	$ 848	$ 986
Long-term financing obligations	16,232	17,023
Total	$ 17,080	$ 18,009

As of March 31, 2006, we have approximately $600 million of debt that is redeemable by holders in 2007, which is prior to its stated maturity date. Additionally, a number of our debt obligations are also callable by us prior to their stated maturity date. At this time, we have approximately $11 billion of debt obligations callable in 2006 and an additional $600 million callable in 2007 and thereafter. To the extent we decide to redeem any of this debt, certain obligations will require us to pay a make whole premium.

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Long-Term Financing Obligations

From January 1, 2006 through the date of this filing, we had the following changes in our long-term financing obligations:

Company	Type	Interest Rate	Book Value Increase (Decrease)	Cash Paid
			(In millions)	
Coastal Finance I	Trust originated preferred securities	8.375%	$ (300)	$ (300)
El Paso	Zero coupon debentures		(612)	(612)
El Paso	Euro notes	5.75%	(26)	(26)
Other	Long-term debt	Various	9	(10)
	Decrease through March 31, 2006		$ (929)	$ (948)
El Paso	Term Loan	LIBOR + 2.75%	(125)	(125)
Other	Long-term debt	Various	(4)	(4)
	Decreases through May 5, 2006[(1)]		$ (1,058)	$ (1,077)

(1) Excludes $229 million repaid prior to closing the sale of our Macae facilities which are classified as discontinued operations.

Prior to their redemption in 2006, we recorded accretion expense on our zero coupon bonds, which increased the principal balance each period and was included in long-term debt. During the quarters ended March 31, 2006 and 2005, the accretion amounts recorded were $4 million and $7 million. During the quarter ended March 31, 2006 and 2005, we redeemed $612 million and $185 million of our zero coupon debentures, of which $110 million and $26 million represented increased principal due to the accretion of interest on the debentures. We account for these redemptions as financing activities in our statement of cash flows.

Credit Facilities

As of March 31, 2006, we had borrowing capacity under our $3 billion credit agreement of $0.2 billion. Amounts outstanding under the credit agreement were a $1.2 billion term loan and $1.6 billion of letters of credit. Our $400 million credit facility matured in May 2006. For a further discussion of our credit agreements and other credit facilities, as well as the related restrictive financial and non-financial covenants and restrictions, see our 2005 Annual Report on Form 10-K.

Letters of Credit

As of March 31, 2006, we had outstanding letters of credit of approximately $1.9 billion of which approximately $0.2 billion related to Macae. Approximately $1.1 billion collateralize our recorded obligations related to price risk management activities.

9. Commitments and Contingencies

Legal Proceedings

Shareholder/ Derivative/ ERISA Litigation

Shareholder Litigation. Twenty-eight purported shareholder class action lawsuits have been pending since 2002 and are consolidated in federal court in Houston, Texas. This consolidated lawsuit alleges violations of federal securities laws against us and several of our current and former officers and directors. It includes allegations regarding the accuracy or completeness of press releases and other public statements made during the period from 2000 through early 2004 related to alleged wash trades, mark-to-market accounting, off-balance sheet debt, the estimation of natural gas and oil reserves and deliveries to the California energy market. Formal discovery in the consolidated lawsuit is currently stayed. The Court has ordered the parties to mediate this case.

Derivative Litigation. Three shareholder derivative actions are outstanding, including two in federal court in Houston and one in state court in Houston. The federal court cases generally allege the same claims pled in the consolidated shareholder class action, with the exception that there are no allegations related to natural gas and oil reserves in one of the cases. The state court action generally alleges the same claims pled in the consolidated shareholder class action, as well as seeks the recovery of 2001 compensation paid to certain former executives. The parties are engaged in settlement discussions in this derivative action.

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 communication with participants in our 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. Formal discovery in this lawsuit is currently stayed.

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

Cash Balance Plan Lawsuit. In December 2004, a purported class action 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 alleges various violations of ERISA and/or the Age Discrimination in Employment Act as a result of our change from a final average earnings formula pension plan to a cash balance pension plan. 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 believed that our liability for these benefits is limited to certain previously established 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 Co. 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. 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 separate rulings in 2004, the court ruled that, pending a trial on the merits, Case must pay the amounts incurred above the cap and that El Paso must reimburse Case for those payments. In January 2006, these rulings were upheld on appeal before a 3-member panel of the U.S. Court of Appeals for the 6th Circuit. In February 2006, we filed for a review of this decision by the full panel of the U.S. Court of Appeals for the 6th Circuit as a result of conflicting precedent. In March 2006, the plaintiff filed a reply brief, as requested by the appellate court. If such a review is not granted, we will proceed with a trial on the merits with regard to the issue of whether the cap is enforceable. Until this is resolved, El Paso will indemnify Case for any payments Case makes above the cap, which are currently about $1.7 million per month. We continue to defend the action and have filed for approval by the trial court various amendments to the medical benefit plans which would allow us to deliver the benefits to plan participants in a more cost effective manner. We will seek expeditious approval of such plan amendments. Although it is uncertain what plan amendments will ultimately be approved, the approval of plan amendments could reduce our overall costs and, as a result, could reduce our recorded liability. We have established an accrual for this matter which we believe is adequate.

Natural Gas Commodities Litigation. Beginning in August 2003, several lawsuits have been filed against 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 information to industry trade publications that published gas indices. The first cases were filed in the U.S. District Court for the Southern District of New York, which included: *Cornerstone Propane Partners, L.P. v. Reliant Energy*

Services Inc., et al.; *Roberto E. Calle Gracey v.*

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American Electric Power Company, Inc., et al.; and *Dominick Viola v. Reliant Energy Services Inc., et al.* In December 2003, those cases were consolidated in federal court in New York for all pre-trial purposes. The consolidated cases are styled, *in re: Gas Commodity Litigation.* In September 2005, the court certified the class to include all persons who purchased or sold NYMEX natural gas futures between January 1, 2000 and December 31, 2002. Other defendants in the case have negotiated tentative settlements with the plaintiffs that are subject to court approval. EPM and the remaining defendants have petitioned the U.S. Court of Appeals for the Second Circuit for permission to appeal the class certification order. The second set of cases involve similar allegations on behalf of commercial and residential customers. These cases were filed in the U.S. District Court for the Eastern District of California, which include *Texas Ohio Energy, Inc. v. CenterPoint Energy, Inc. et al.* (filed in November 2003); *Fairhaven Power v. El Paso Corporation et al.*(filed in September 2004); *Utility Savings and Refund Services, et al. v. Reliant Energy, et al.* (filed in December 2004); and *Abelman Art Glass, et al. v. Encana Corporation, et al.* (filed in December 2004). Each of these cases was transferred to a multi-district litigation proceeding (MDL), in *re Western States Wholesale Natural Gas Antitrust Litigation,* pending in the U.S. District Court for Nevada. These cases have been dismissed and have been appealed. The third set of cases also involve similar allegations on behalf of certain purchasers of natural gas. These include a purported class action lawsuit styled *Leggett et al. v. Duke Energy Corporation et al.* (filed in Chancery Court of Tennessee in January 2005); the purported class action *Ever-Bloom Inc. v. AEP Energy Services Inc. et al.* (filed in federal court for the Eastern District of California in June 2005); *Farmland Industries, Inc. v. Oneok Inc.*(filed in state court in Wyandotte County, Kansas in July 2005); and the purported class action *Learjet, Inc. v. Oneok Inc.* (filed in state court in Wyandotte County, Kansas in September 2005). All four actions have been transferred to the MDL proceeding in federal district court in Nevada. Similar motions to dismiss have either been filed or are anticipated to be filed in these cases as well. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Gas Measurement Cases. A number of our subsidiaries were named defendants in actions that generally allege a mismeasurement of natural gas volumes and/or heating content resulting in the underpayment of royalties. The first set of cases was filed in 1997 by an individual under the False Claims Act, which has been consolidated for pretrial purposes (in *re: Natural Gas Royalties Qui Tam Litigation,* U.S. District Court for the District of Wyoming.) 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. In May 2005, a representative appointed by the court issued a recommendation to dismiss most of the actions on jurisdictional grounds. If the court adopts these recommendations, it will result in the dismissal on jurisdictional grounds of six of the district court actions involving most of the El Paso entities named as defendants. The seventh case involves only a few midstream entities previously owned by El Paso, which have meritorious defenses to the underlying claims. Similar allegations were filed in a second action in 1999 in *Will Price, et al. v. Gas Pipelines and Their Predecessors, et al.,* in the District Court of Stevens County, Kansas on non-federal and non-Native American lands. The plaintiffs currently seek certification of a class of royalty owners in wells in Kansas, Wyoming and Colorado. Motions for class certification have been briefed and argued in the proceedings and the parties are awaiting the court s ruling. In each of these cases, the applicable plaintiff seeks an unspecified amount of monetary damages in the form of additional royalty payments (along with interest, expenses and punitive damages) and injunctive relief with regard to future gas measurement practices. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Hurricane Litigation. One of our affiliates has been named in two class action petitions for damages filed in the U.S. District Court for the Eastern District of Louisiana against all oil and natural gas pipeline and production companies that dredged pipeline canals, installed transmission lines or drilled for oil and natural gas in the marshes of coastal Louisiana. The lawsuits, *George Barasich, et al. v. Columbia Gulf Transmission Company, et al.* and *Charles Villa Jr., et al. v. Columbia Gulf Transmission Company, et al.* assert that the defendants caused erosion and land loss, which destroyed critical protection against hurricane surges and winds and was a substantial cause of the loss of life and destruction of property. The first lawsuit alleges damages associated with Hurricane Katrina. The second lawsuit alleges damages associated with Hurricanes Katrina and Rita. The court consolidated the two lawsuits. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

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Bank of America. We are a named defendant, along with Burlington Resources, Inc. (Burlington), 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 consolidated class action has been settled pursuant to a settlement agreement executed in January 2006. 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. All the claims in this action have been settled as part of the January 2006 settlement. The settlement of all these claims is subject to court approval, after a fairness hearing scheduled in the second quarter of 2006. We 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, Texas relating to indemnity issues between Burlington and us. That action was stayed by agreement of the parties and settled in November 2005, subject to the underlying class settlements being finalized and approved by the court. Upon final court approval of these settlements, our contribution will be approximately $30 million plus interest, which has been accrued as of March 31, 2006.

Araucaria. We own a 60 percent interest in a 484 MW gas-fired power project known as the Araucaria project located near Curitiba, Brazil. In December 2002, the utility that had entered into a long-term agreement to purchase power from the project ceased making payments. Various actions have been filed in relation to this failure to continue to make payments, including in local Brazilian courts as well as international arbitration. We expect to settle these disputes and sell our interest in Araucaria to the utility for $190 million in the second quarter of 2006.

Macae. We owned a 928 MW gas-fired power plant known as the Macae project located near the city of Macae, Brazil which generated revenues largely from payments made by Petrobras under a participation agreement that originally extended through August 2007. Petrobras sought rescission of the participation agreement and reimbursement of prior payments that it had made by filing for international arbitration as well as filing a lawsuit in Brazilian courts. Although an initial arbitration award was issued in the proceeding, we entered into an agreement with Petrobras in March 2006 that provides for the settlement of this matter and the sale of the entities that own our interest in the Macae power plant. In April 2006, pursuant to that agreement, we repaid all of the approximately $229 million of outstanding debt on the plant and completed the sale of our interest in the facility to Petrobras for approximately $358 million, thereby fully resolving the matters in dispute with Petrobras. As part of the sale, we indemnified Petrobras against certain customary liabilities, including any liability associated with a proposed Brazilian tax assessment of $78 million. We have retained the control of defense of these matters and believe we have valid defenses and have challenged the assessment with the Brazilian tax authorities. We also retained rights to receive half of any net refund or other tax benefits received in respect of the companies sold, including half of an approximately $11 million income tax receivable related to overpayment of estimated income taxes in 2004 and 2005 and half of a potential tax benefit of approximately $23 million in respect of tax payments that were previously made related to interest income that has recently been determined to be unconstitutional in a similar case.

MTBE. In compliance with the 1990 amendments to the Clean Air Act, certain of our subsidiaries used the gasoline additive MTBE in some of their gasoline. Certain subsidiaries 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. Some of our subsidiaries are among the defendants in over 65 such lawsuits. These suits either 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, various water districts and a limited number of individual water customers seek remediation of their groundwater, prevention of future contamination, a variety of compensatory damages, punitive damages, attorney s fees, court costs and, in one lawsuit, a request for medical monitoring. Among other allegations, plaintiffs assert that gasoline containing MTBE is a defective product and that defendant refiners are liable in proportion to their market share. The plaintiff states of California and New Hampshire have filed an appeal to the 2nd Circuit Court of Appeals challenging the removal of the cases from state to federal court. That appeal is pending. Various motions to dismiss or limit the scope of the lawsuits have been

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filed and are pending court review. Our costs and legal exposure related to these lawsuits are not currently determinable.

Government Investigations and Inquiries

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 will continue to cooperate with the SEC in its investigation related to such reserve revisions. Although we had also received federal grand jury subpoenas for documents with regard to these reserve revisions, in June 2005, we were informed that the U.S. Attorney s office closed this investigation and will not pursue prosecution at this time.

Iraq Oil Sales. Several government agencies and congressional committees have been reviewing and making formal and informal requests related to The Coastal Corporation s and El Paso s purchases of crude oil from Iraq under the United Nations Oil for Food Program. These agencies include a grand jury of the U.S. District Court for the Southern District of New York, the SEC and several congressional committees. In October 2005, a grand jury sitting in the Southern District of New York handed down an indictment against Oscar S. Wyatt, Jr., a former CEO and Chairman of Coastal. Also in October 2005, the Independent Inquiry Committee into the United Nations Oil for Food Program issued its final report. The report states that $201,877 in surcharges were paid with respect to a single contract entered into by our subsidiary, Coastal Petroleum NV (CPNV). The report lists Oscar Wyatt as the non-contractual beneficiary of the contract. The report indicates that the payments were made by two other individuals or entities and does not contend that CPNV paid that surcharge. We continue to cooperate with all government investigations into this matter.

Other Government Investigations. We also continue to provide information and cooperate with the inquiry or investigation of the U.S. Attorney and the SEC in response to requests for information regarding price reporting of transactional data to the energy trade press and the hedges of our natural gas production.

Other Contingencies

El Paso Natural Gas Company Rate Case. In June 2005, EPNG filed a rate case with the Federal Energy Regulatory Commission proposing an increase in revenues of 10.6 percent or $56 million over current tariff rates, new services and revisions to certain terms and conditions of existing services, including the adoption of a fuel tracking mechanism. As part of this filing, we proposed to modify our depreciation rates to a range of approximately two percent to 20 percent per year. On January 1, 2006, the tariff rates and depreciation rates, which are subject to refund, and the fuel tracking mechanism became effective. In March 2006, the FERC issued orders that addressed the applicability for a rate cap set forth in a prior rate case settlement, as well as generally approved our proposed new services. The FERC accepted a delay in the implementation date of the new services until June 1, 2006, pending further action. In April 2006, we solicited and received bids for certain new services and are currently evaluating those bids. EPNG is continuing settlement discussions with its customers. The outcome of this rate case cannot be predicted with certainty at this time.

Colorado Interstate Gas Company (CIG) Rate Case. CIG anticipates filing a new rate case by June 30, 2006. In March 2006, the FERC granted CIG s request to change the effective date of its proposed new rates to no later than January 1, 2007. CIG is engaged in settlement discussions with its customers. The outcome of this rate case and its impact on revenues cannot be predicted with certainty at this time.

Iraq Imports. In December 2005, the Ministry of Oil for the State Oil Marketing Organization of Iraq (SOMO) sent an invoice to one of Coastal s subsidiaries with regard to shipments of crude oil that SOMO alleged were purchased and paid for by Coastal in 1990. The invoices request an additional $144 million of payments for such shipments, along with an allegation of an undefined amount of interest. The invoice appears to be associated with cargoes that Coastal had purchased just before the 1990 invasion of Kuwait by Iraq. We have requested additional information from SOMO to further assist in our evaluation of the invoice and the underlying facts. In addition, we are evaluating our legal defenses, including applicable statute of limitation periods.

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Navajo Nation. Approximately 900 looped pipeline miles of the north mainline of our EPNG pipeline system are located on lands held in trust by the United States for the benefit of the Navajo Nation. Although our rights-of-way on lands crossing the Navajo Nation expired in October 2005, we entered into an interim agreement with the Navajo Nation to extend our use of existing rights-of-way through the end of 2006. Negotiations on the terms of the long-term agreement are continuing. Although the Navajo Nation has at times demanded more than ten times the $2 million annual fee that existed prior to the execution of the interim agreement, EPNG continues to offer a combination of cash and non-cash consideration, including collaborative projects to benefit the Navajo Nation. In addition, EPNG continues to preserve other legal and regulatory alternatives, which include continuing to pursue our application with the Department of the Interior for renewal of our rights-of-way on Navajo Nation lands. EPNG also continues to press for public policy intervention by Congress in this area. The Energy Policy Act of 2005 commissioned a comprehensive study of energy infrastructure rights-of-way on tribal lands. The study, to be conducted jointly by the Department of Energy and the Department of Interior, must be submitted to Congress by August 2006. It is uncertain whether our negotiation, public policy or litigation efforts will be successful, or if successful, what will be the ultimate cost of obtaining the rights-of-way or whether EPNG will be able to recover these costs in its rate case.

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. 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, discussed above, 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, and these adjustments could be material. As of March 31, 2006, we had approximately $560 million accrued, net of related insurance receivables, for outstanding legal and other contingent matters.

Environmental Matters

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. As of March 31, 2006, we have accrued approximately $379 million, which has not been reduced by $27 million for amounts to be paid directly under government sponsored programs. Our accrual includes approximately $368 million for expected remediation costs and associated onsite, offsite and groundwater technical studies and approximately $11 million for related environmental legal costs. Of the $379 million accrual, $72 million was reserved for facilities we currently operate and $307 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 $379 million to approximately $540 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 ($72 million). Second, where the most likely outcome cannot be estimated, a range of costs is established ($307 million to $468 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. Our environmental remediation projects are in various stages of completion. Our recorded liabilities reflect our current estimates of amounts we will expend to remediate these sites. However, depending on the stage of completion or assessment, the ultimate extent of contamination or remediation required may not be known. As

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additional assessments occur or remediation efforts continue, we may incur additional liabilities. By type of site, our reserves are based on the following estimates of reasonably possible outcomes:

	March 31, 2006	
Sites	Expected	High
	(In millions)	
Operating	$ 72	$ 73
Non-operating	269	399
Superfund	38	68
Total	$ 379	$ 540

Below is a reconciliation of our accrued liability from January 1, 2006 to March 31, 2006 (in millions):

Balance as of January 1, 2006	$ 379
Additions/adjustments for remediation activities	14
Payments for remediation activities	(14)
Balance as of March 31, 2006	$ 379

For the remainder of 2006, we estimate that our total remediation expenditures will be approximately $78 million, most of which will be expended under government directed clean-up plans. In addition, we expect to make capital expenditures for environmental matters of approximately $91 million in the aggregate for the years 2006 through 2010. 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 Company (TGP), our wholly owned subsidiary, in May 1994, with the Environmental Protection Agency (EPA), TGP has been conducting various remediation activities at certain of its compressor stations associated with the presence of PCB and certain other hazardous materials. TGP has recovered a substantial portion of the environmental costs identified in its PCB remediation project through a surcharge to its customers. An agreement with TGP s customers, approved by the FERC in November 1995, established the surcharge mechanism. The current surcharge collection period is currently set to expire in June 2006, with further extensions subject to a filing with the FERC. As of March 31, 2006, TGP had pre-collected PCB costs of approximately $134 million. This 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. At March 31, 2006, TGP had a regulatory liability of $120 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 51 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, 2006, we have estimated our share of the remediation costs at these sites to be between $38 million and $68 million. Because the clean-up costs are estimates and are subject to revision as more information becomes available about the extent of remediation required, and 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

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increasingly strict environmental laws, regulations and orders of regulatory agencies, as well as claims for damages to property and the environment or injuries to employees and other persons resulting from our current or past operations, could result in substantial costs and liabilities in the future. As this information becomes available, or other relevant developments occur, we will adjust our accrual amounts accordingly. While there are still uncertainties related to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe our reserves are adequate.

Guarantees

We are involved in various joint ventures and other ownership arrangements that sometimes require additional financial support that results in the issuance of financial and performance guarantees. See our 2005 Annual Report on Form 10-K for a description of these commitments. As of March 31, 2006, we had a liability of $69 million related to our guarantees and indemnification arrangements. These arrangements had a total stated value of $212 million, for which we are indemnified by third parties for $26 million. These amounts exclude guarantees for which we have issued related letters of credit discussed in Note 8.

In addition to the exposures described above, a trial court has ruled, which was upheld on appeal, that we are required to indemnify a third party for benefits being paid to a closed group of retirees of one of our former subsidiaries. We have a liability of approximately $380 million associated with our estimated exposure under this matter as of March 31, 2006. For a further discussion of this matter, see *Retiree Medical Benefits Matters* above.

10. 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	
	2006	**2005**	**2006**	**2005**
		(In millions)		
Service cost	$ 4	$ 6	$	$
Interest cost	29	29	7	7
Expected return on plan assets	(44)	(42)	(4)	(3)
Amortization of net actuarial loss	14	16		
Amortization of prior service cost[1]		(1)		2
Net benefit cost	$ 3	$ 8	$ 3	$ 6

[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.

We made $11 million and $18 million of cash contributions to our Supplemental Executive Retirement Plan (SERP) and other postretirement plans during the quarters ended March 31, 2006 and 2005. We expect to contribute an additional $3 million to the SERP and $35 million to our other postretirement plans for the remainder of 2006. Contributions to our other retirement benefit plans will be approximately $11 million for the remainder of 2006.

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11. Capital Stock

The table below shows the amount of dividends paid and declared (in millions, except per share amounts).

	Common Stock ($0.04/share)	Convertible Preferred Stock (4.99%/year)
Amount paid through March 31, 2006	$26	$10
Amount paid in April 2006	$26	$ 9
Declared subsequent to March 31, 2006:		
Date of declaration	April 13, 2006	April 13, 2006
Date payable	July 3, 2006	July 3, 2006
Payable to shareholders on record	June 2, 2006	June 15, 2006

Dividends on our common stock are treated as a reduction of additional paid-in-capital since we currently have an accumulated deficit. We expect dividends paid on our common and preferred stock in 2006 will be taxable to our stockholders because we anticipate that these dividends will be paid out of current or accumulated earnings and profits for tax purposes. For a further discussion of our common and preferred stock including dividend restrictions, refer to our 2005 Annual Report on Form 10-K.

12. Stock-Based Compensation

Under our stock-based compensation plans, we may issue to our employees incentive stock options on our common stock (intended to qualify under Section 422 of the Internal Revenue Code), non-qualified stock options, restricted stock, restricted stock units, stock appreciation rights, performance shares, performance units and other stock-based awards. We are authorized to grant awards of approximately 42.5 million shares of our common stock under our current plans, which includes 35 million shares under our employee plan, 2.5 million shares under our non-employee director plan and 5 million shares under our employee stock purchase plan. At March 31, 2006, approximately 40 million shares remain available for grant under our current plans. In addition, we have approximately 25 million shares of stock option awards outstanding that were granted under terminated plans that obligate us to issue additional shares of common stock if they are exercised. Stock option exercises and restricted stock are funded primarily through the issuance of new common shares.

As discussed in Note 1, we adopted SFAS No. 123(R) on January 1, 2006 and began recognizing the cost of all of our stock-based compensation arrangements based on the grant date fair value of those awards in our financial statements. We record this cost as operation and maintenance expense in our consolidated statements of income over the requisite service period for each separately vesting portion of the award net of estimates of pre-vesting forfeiture rates. If actual forfeitures differ from our estimates, additional adjustments to compensation expense will be required in future periods.

The impact of the adoption of SFAS No. 123(R) on earnings per share was less than $0.01 per basic and diluted share for the quarter ended March 31, 2006. During the quarter ended March 31, 2006, we recognized $3 million of additional pre-tax compensation expense while capitalizing less than $1 million as part of fixed assets and recording $1 million of income tax benefits as our option awards vested. We expect to record incremental compensation expense of approximately $9 million for the remainder of the year.

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Had we accounted for our stock-based compensation awards using the fair value recognition provisions of SFAS No. 123 for historical periods, rather than APB No. 25, the net income available to common stockholders and per share impacts on our financial statements would have been different. The following table shows the impact on net income available to common stockholders and income per share had we applied SFAS No. 123 (in millions, except for per share amounts):

		Quarter Ended March 31, 2005
Net income available to common stockholders, as reported	$	106
Add: Stock-based employee compensation expense included in reported net income, net of taxes		2
Deduct: Total stock-based compensation expense, determined under fair-value based method for all awards, net of taxes		5
Net income available to common stockholders, pro forma	$	103
Income per share:		
Basic and diluted, as reported	$	0.17
Based and diluted, pro forma	$	0.16

We follow the transition method described in SFAS No. 123(R) for calculating the historical pool of excess tax benefits available (the APIC Pool) to absorb any tax deficiencies recognized after January 1, 2006, if actual tax benefits realized upon the exercise of stock options are less than the recorded tax benefit. We are currently evaluating whether to elect the one-time transition election for calculating the APIC pool provided in FASB Staff Position (FSP) SFAS 123(R)-3, *Transition Election to Accounting for the Tax Effects of Share-Based Payment Awards*.

Under SFAS No. 123(R), beginning January 1, 2006, excess tax benefits from the exercise of stock-based compensation awards are recognized in cash flows from financing activities. Prior to this date, these amounts were recorded in cash flows from operating activities. Our excess tax benefits recorded in 2006 and 2005 were not material.

Non-Qualified Stock Options

We grant non-qualified stock options to our employees with an exercise price equal to the market value of our stock on the grant date. Our stock option awards have contractual terms of 10 years and generally vest after completion of one to five years of continuous employment from the grant date. We do not pay dividends on unexercised options. A summary of our stock option transactions for the quarter ended March 31, 2006 is presented below:

	# Shares Underlying Options		Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Term (In years)	Aggregate Intrinsic Value (In millions)
Outstanding at December 31, 2005	28,083,485	$	37.12		

Granted	22,825	$	12.42				
Exercised	(18,363)	$	7.09				
Forfeited or canceled	(68,952)	$	10.92				
Expired	(2,339,574)	$	37.56				
Outstanding at March 31, 2006	25,679,421	$	37.15	5.1	$	30
Vested or expected to vest at March 31, 2006	25,319,828	$	37.55	5.1	$	29
Exercisable at March 31, 2006	18,487,570	$	48.07	3.8	$	8

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Total compensation cost related to non-vested option awards not yet recognized at March 31, 2006 was approximately $11 million, which is expected to be recognized over a weighted average vesting period of 13 months. The total intrinsic value, cash received and income tax benefits generated from option exercises were not material during the quarters ended March 31, 2006 and 2005.

Fair Value Assumptions. The fair value of each stock option granted is estimated on the date of grant using a Black-Scholes option-pricing model based on several assumptions. These assumptions are based on management s best estimate at the time of grant. For the quarters ended March 31, 2006 and 2005, the weighted average grant date fair value per share of options granted was $4.99 and $3.67. Listed below is the weighted average of each assumption based on grants in each of the quarters ended March 31:

	2006	**2005**
Expected Term in Years	6.25	4.68
Expected Volatility	38%	41%
Expected Dividends	1.3%	1.4%
Risk-Free Interest Rate	4.7%	4.2%

Our expected volatilities are based on an analysis of implied volatilities from traded options on our common stock and our historical stock price volatility over the expected term, adjusted for certain time periods. Prior to January 1, 2006, we estimated expected volatility based primarily on adjusted historical stock price volatility. Effective January 1, 2006, we adopted the provisions of Staff Accounting Bulletin No. 107 and estimate the expected term of our option awards based on the vesting period and average remaining contractual term.

Restricted Stock

We may grant shares of restricted common stock, which carry voting and dividend rights, to our officers and employees. However, sale or transfer of the shares is restricted until they vest. We currently have outstanding and grant only time-based restricted stock. Historically, we also granted performance-based restricted share awards. These shares have fully vested or were forfeited prior to the end of 2005. The fair value of our time-based restricted shares is determined on the grant date and typically vest over three years from the date of grant. A summary of the changes in our non-vested restricted shares for the quarter ended March 31, 2006, is presented below:

Nonvested Shares	**# Shares**	**Weighted-Average Grant Date Fair Value Per Share**
Nonvested at December 31, 2005	3,916,030	$ 10.83
Granted	17,592	$ 12.60
Vested	(681,600)	$ 18.05
Forfeited	(30,025)	$ 9.78
Nonvested at March 31, 2006	3,221,997	$ 9.32

The weighted average grant date fair value per share for restricted stock granted during the first quarter of 2006 and 2005 was $12.60 and $10.35. The total fair value of shares vested during the quarters ended March 31, 2006 and 2005 was $9 million and $5 million.

During the quarters ended March 31, 2006 and 2005, we recognized approximately $4 million of pre-tax compensation expense, capitalized less than $1 million as part of fixed assets and recorded $1 million of income tax benefits related to restricted stock arrangements. The total unrecognized compensation cost related to these arrangements at March 31, 2006 was approximately $13 million, which is expected to be recognized over a weighted average vesting period of 18 months. Upon adoption of SFAS No. 123(R), we recorded a cumulative effect of a change in accounting principle of less than $1 million as a result of estimating forfeitures for restricted stock on the date of grant as compared to recognizing forfeitures as they occur. We also reclassified unearned compensation as additional paid-in capital on our balance sheet as required by this standard.

Employee Stock Purchase Plan

In July 2005, we reinstated our employee stock purchase plan under Section 423 of the Internal Revenue Code. The amended and restated plan allows participating employees the right to purchase our common stock at 95 percent of the market price on the last trading day of each month. This plan is non-compensatory under the provisions of SFAS No. 123(R).

13. Business Segment Information

As of March 31, 2006, our business consists of our core Pipelines and Exploration and Production segments, as well as our Marketing and Trading and Power segments. Prior to 2006, we also had a Field Services segment. As of January 1, 2006, we had divested of substantially all of the assets and operations in this segment. 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 2006, our Board of Directors approved the sale of our interest in the Macae power facility in Brazil to Petrobras, and as a result, we reclassified these operations as discontinued. During 2005, we reclassified our south Louisiana gathering and processing assets, which were part of our historical Field Services segment, and the international power operations at our Nejapa, CEBU and East Asia Utilities power plants as discontinued operations. 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) 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 flows. Below is a reconciliation of our EBIT to our income from continuing operations for the quarters ended March 31:

	2006	2005
	(In millions)	
Total EBIT	$ 888	$ 463
Interest and debt expense	(348)	(343)
Preferred interests of consolidated subsidiaries		(6)
Income taxes	(165)	(1)
Income from continuing operations	$ 375	$ 113

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

	Segments					
	Pipelines	Exploration and Production	Marketing and Trading	Power	Corporate[1]	Total
	(In millions)					
2006						
Revenues from external customers	$ 823	$ 81[(2)]	$ 598	$ 1	$ 28	$ 1,531
Intersegment revenues	14	385[(2)]	(393)		(6)	
Operation and maintenance	217	88	3	14	12	334
Depreciation, depletion and amortization	115	146	1		10	272
Earnings (losses) from unconsolidated affiliates	32	7		7	(1)	45
EBIT	478	199	208	3		888

	Segments						
	Pipelines	Exploration and Production	Marketing and Trading	Power	Field Services	Corporate[1]	Total
	(In millions)						
2005							
Revenues from external customers	$ 748	$ 131[(2)]	$ 93	$ 25	$ 42	$ 27	$ 1,066
Intersegment revenues	20	308[(2)]	(268)	(2)	6	(42)	22[(3)]
Operation and maintenance	203	84	10	20	(1)	95	411
Depreciation, depletion and amortization	111	146	1	1	1	9	269
(Gain) loss on long-lived assets	(7)			13	1		7
Earnings (losses) from unconsolidated affiliates	38			(28)	180		190
EBIT	412	183	(185)	(39)	182	(90)	463

(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, 2006 and 2005, we recorded an intersegment revenue elimination of $6 million and $42 million and an operation and maintenance expense elimination of less than $1 million, which is included in the Corporate column, to remove intersegment transactions.

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

which is responsible for marketing our production.

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

Total assets by segment are presented below:

	March 31, 2006	December 31, 2005
	(In millions)	
Pipelines	$ 16,683	$ 16,447
Exploration and Production	5,713	5,570
Marketing and Trading	2,769	3,819
Power	1,188	1,176
Field Services		99
Total segment assets	26,353	27,111
Corporate	3,611	4,144
Discontinued operations	637	583
Total consolidated assets	$ 30,601	$ 31,838

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14. Investments in Unconsolidated Affiliates and Related Party Transactions

We hold investments in unconsolidated affiliates, which are accounted for using the equity method of accounting. Our income statement typically reflects (i) our share of net earnings directly attributable to these unconsolidated affiliates and (ii) impairments and other adjustments recorded by us. Our net ownership interest and earnings (losses) from our unconsolidated affiliates are as follows:

	Net Ownership Interest	Earnings (Losses) from Unconsolidated Affiliates	
		Quarter Ended March 31,	
	March 31, 2006	2006	2005
	(Percent)	(In millions)	
Domestic:			
Enterprise Products Partners, L.P. (Enterprise)[(1)]		$	$ 183
Four Star[(2)]	43	7	
Citrus	50	10	15
Great Lakes	50	16	17
Other Domestic Investments	various		4
Total domestic		33	219
Foreign:			
Asia Investments[(3)]	various	3	(46)
Central American Investments[(4)]	various	(2)	6
Other Foreign Investments	various	11	11
Total foreign		12	(29)
Total earnings from unconsolidated affiliates		$ 45	$ 190

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

(2) We acquired our interest in Four Star in connection with our acquisition of Medicine Bow in the third quarter of 2005.

(3) As of March 31, 2006, consists of our investments in 6 power plants, all of which are under sales contracts.

(4) As of March 31, 2006, consists of our investments in 6 power plants, three of which were sold in April 2006 and two others which are under sales contracts.

Impairment charges and gains and losses on sales of equity investments are included in earnings (losses) from unconsolidated affiliates. During the quarters ended March 31, 2006 and 2005, our impairment gains and losses were primarily a result of our decision to sell these investments. We also had investments that experienced declines in their fair value due to changes in economics of the investments underlying contracts or the markets they serve. These gains and losses consisted of the following for the quarters ended March 31:

Investment or Group	2006	2005
	(In millions)	
Asian power investment	$	$ (60)
Central American power investments	(2)	
Enterprise		183
Other		(4)
	$ (2)	$ 119

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The summarized financial information below includes our proportionate share of the operating results of our unconsolidated affiliates for the quarters ended March 31:

	2006	2005
	(In millions)	
Operating results data		
Revenues	$ 339	$ 348
Operating expenses	278	141
Income (loss) from continuing operations	(8)	159
Net income (loss)[1]	(8)	159

[1] Includes net income of $5 million and $3 million for the quarters ended March 31, 2006 and 2005, 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 $55 million and $83 million for the quarters ended March 31, 2006 and 2005.

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:

	2006	2005
	(In millions)	
Operating revenue	$ 34	$ 49
Cost of sales	1	4
Reimbursement for operating expenses	1	1
Other income	13	14

Matters that Could Impact Our Investments

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 and on February 9, 2006, the lenders declared all obligations outstanding under the loan agreement to be immediately due and payable in full. This obligation is non-recourse to El Paso. We have previously fully impaired the value of this investment. However, we supply natural gas to Berkshire under a fuel management agreement in effect until June 2020. Berkshire had the ability to delay payment of 33 percent of the amounts due to us under the fuel supply agreement, up to a maximum of $49 million which Berkshire reached in March 2005. We reserved the cumulative amount of the delayed payments based on Berkshire s inability to generate adequate cash flows related to this agreement. We continue to supply fuel to the plant under the fuel supply agreement and we may incur losses if amounts owed on future fuel deliveries are not paid under this agreement because of Berkshire s inability to generate adequate cash flow and the uncertainty surrounding their negotiations with their lenders. We are in discussions with the lenders and other owners of the project to transfer or terminate our interest in this project and the fuel management agreement.

We supply gas to power plants that we partially own, including the Midland Cogeneration Venture (MCV) and Berkshire power projects. Due to their affiliated nature, we do not recognize mark-to-market gains or losses on these contracts to the extent of our ownership interest. All amounts related to Berkshire are fully reserved as of March 31, 2006. However, should we sell our interest in MCV, we would record the cumulative unrecognized mark-to-market losses on these contracts, which totaled approximately $132 million as of March 31, 2006. We also have issued letters of credit and margin deposits to MCV for approximately $303 million and $24 million as of March 31, 2006, securing our obligation under the gas supply contracts.

Investment in Bolivia. We own an eight percent interest in the Bolivia to Brazil pipeline in which we have approximately $108 million of exposure, including guarantees, as of March 31, 2006. The Bolivian government has announced a new decree significantly increasing its interest in and control over Bolivia s oil and gas assets. We are currently evaluating, together with our partners, the commercial impact that recent political events in Bolivia could have on the Bolivia to Brazil pipeline and will continue to monitor the political situation in Bolivia. As new information becomes available or future material developments arise, it is possible that a future impairment of our investment may occur.

Citrus Corporation. 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., the holding company 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. In the lawsuit, CTC alleged that Duke failed to give proper notice to CTC regarding its failure to maintain the letter of credit. Duke has filed an amended counter claim in federal court joining Citrus and requested 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 has filed motions for partial summary judgment, requesting that the court find that Duke improperly asserted force majeure due to its alleged loss of gas supply and that Duke is in error in asserting that CTC breached contractual provisions that imposed resale restrictions and credit maintenance obligations. An unfavorable outcome on this matter could impact the value of our investment in Citrus, which in turn, could have an effect on us.

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 2005 Annual Report on Form 10-K, and the financial statements and notes presented in Item 1 of this Quarterly Report on Form 10-Q.

In the first quarter of 2006, our Board of Directors approved the sale of our interest in the Macae power facility in Brazil and, as a result, we reclassified these operations as discontinued. During 2005, we reclassified our south Louisiana gathering and processing operations and the international power operations at our Nejapa, CEBU and East Asia Utilities power plants as discontinued operations. Our operating results for all periods presented reflect these operations as discontinued.

Overview

During the first quarter of 2006, we began to return to profitability while continuing to reduce debt and maintaining sufficient liquidity. We continued to grow our core pipeline and exploration and production operations by expanding and maintaining our asset base, while continuing to bring production volumes shut-in by hurricanes in late 2005 back online. Despite a slower than expected recovery from the hurricanes, we returned to profitability during the first quarter of 2006 due to strong financial performance in our exploration and production and pipeline businesses enhanced by a decrease in our overall price risk management liabilities in our marketing and trading business due to a reduction in commodity prices. Our individual segment results provide a further discussion of the events affecting the first quarter of 2006 as well as progress in our key areas of focus.

What to Expect Going Forward. For the remainder of 2006, we anticipate that our pipeline operations will continue to provide consistent operating results based on the current levels of contracted capacity, expansion plans and the status of rate and regulatory actions. The success of our exploration and production business will be driven by continued success of our drilling programs, our ability to restore the remaining production that has been shut-in since late September 2005 due to Hurricane Rita, our ability to manage increases in the cost of production services and continued high commodity prices. Additionally, a substantial portion of our below-market derivative contracts are scheduled to expire in 2006, which will give us a greater opportunity to participate in the current higher commodity pricing environment.

During the remainder of 2006, we anticipate completing the sale of our Asian and Central American power assets (substantially all of which are under contract) and pursuing the divestiture of our remaining domestic power assets. We will also complete the assignment of our power portfolio agreed to in December 2005 as well as further the resolution of other remaining legacy issues, which will position us to achieve our net debt target (debt, less cash) of $14 billion by the end of 2006 and further our return to profitability.

Segment Results

Below are our results of operations (as measured by EBIT) by segment. Our business segments consist of our core Pipelines and Exploration and Production segments, as well as our Marketing and Trading and Power segments. Prior to 2006, we also had a Field Services segment. As of January 1, 2006, we had divested of substantially all of the assets and operations in this segment. Our segments are strategic business units that provide a variety of energy products and services. They are managed separately as each 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.

We use 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) preferred interests of consolidated subsidiaries. Our business operations consist of both consolidated businesses as well as investments in unconsolidated affiliates. We

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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 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 for the quarters ended March 31:

	2006	2005
	(In millions)	
Pipelines	$ 478	$ 412
Exploration and Production	199	183
Marketing and Trading	208	(185)
Power	3	(39)
Field Services		182
Segment EBIT	888	553
Corporate		(90)
Consolidated EBIT from continuing operations	888	463
Interest and debt expense	348	343
Preferred interests of consolidated subsidiaries		6
Income taxes	165	1
Income from continuing operations	375	113
Discontinued operations, net of income taxes	(19)	(7)
Net income	$ 356	$ 106

Pipelines Segment

Operating Results

Below are the operating results for our Pipelines segment as well as a discussion of factors impacting EBIT for the quarters ended March 31:

	2006	2005
	(In millions)	
Operating revenues	$ 837	$ 768
Operating expenses	(399)	(406)
Operating income	438	362
Other income	40	50
EBIT	$ 478	$ 412
Throughput volumes (BBtu/d)	22,306	22,586

	Variance			
	Revenue Impact	Expense Impact	Other Impact	EBIT Impact
	Favorable/(Unfavorable) (In millions)			
Higher services revenues	$ 59	$	$	$ 59
Gas not used in operations, revaluations, processing revenues and other natural gas sales	17	16		33
Pipeline expansions	19	(1)	(1)	17
Contract restructuring in 2005	(29)			(29)
Hurricanes Katrina and Rita		(10)		(10)
Equity earnings from Citrus			(5)	(5)
Other[1]	3	2	(4)	1
Total impact on EBIT	$ 69	$ 7	$ (10)	$ 66

[1] Consists of individually insignificant items on several of our pipeline systems.

Higher Services Revenues. During the quarter ended March 31, 2006, our reservation revenues increased primarily due to the termination, effective December 31, 2005, of reduced tariff rates that were in place under the terms of EPNG s FERC-approved systemwide capacity allocation proceeding, an increase in EPNG s tariff rates which are subject to refund and became effective on January 1, 2006, and higher sales of additional capacity and interruptible capacity on several of our pipeline systems compared to the same period in 2005. In addition, our usage revenues increased due to higher revenues received from increased activity on our pipeline systems under various interruptible services provided under their tariffs.

Gas Not Used in Operations, Revaluations, Processing Revenues and Other Natural Gas Sales. During the first quarter of 2006, sales of excess system supply gas on our ANR Pipeline Company (ANR) pipeline system and a decrease in the index prices used to value the net imbalance position on several of our pipeline systems at December 31, 2005, resulted in favorable impacts on our operating results. These favorable impacts were partially offset by first quarter 2005 sales of higher volumes of natural gas made available by ANR s storage realignment project. We anticipate that the overall activity in this area will continue to vary based on factors such as rate actions, some of which have already been implemented, the efficiency of our pipeline operations, natural gas prices and other factors. For a further discussion of our gas not used in operations, revaluations, processing revenues and other natural gas sales, see our 2005 Annual Report on Form 10-K.

Pipeline Expansions. In January 2005, Phase I of the Cheyenne Plains Gas Pipeline Company, L.L.C. system was fully placed in service and Phase II of this project was placed in service in December 2005. As a result, our revenues increased by $10 million and overall EBIT increased by $9 million during the first quarter 2006 compared to the same period in 2005.

In February 2006, the Elba Island LNG expansion was placed in service resulting in an increase in our operating revenues, partially offset by a reduction in other income due to amounts capitalized in 2005 related to the allowance for funds used during construction. This expansion is estimated to increase our revenues by approximately $29 million annually.

In March 2006, the Piceance Basin project on our Wyoming Interstate Company, Ltd. system was completed and we anticipate completion of the related compression by mid May 2006. Our remaining costs for 2006 related to this project are estimated to be approximately $9 million. In addition, this project is estimated to increase our revenues by $9 million in 2006 and approximately $20 million annually thereafter.

Contract Restructuring/Settlements. In March 2005, ANR completed the restructuring of its transportation contracts with one of its shippers on its southwest and southeast legs as well as a related gathering contract.

Hurricanes Katrina and Rita. We continue to assess the damage caused by Hurricanes Katrina and Rita. We are part of a mutual insurance company and are subject to certain individual and aggregate loss

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limits by event. The mutual insurance company has indicated that aggregate losses for both Hurricanes Katrina and Rita will exceed the per event limits allowed under the program and that we will not receive insurance recoveries of certain costs we have incurred or anticipate incurring. We recorded approximately $10 million in higher operation and maintenance expenses during the first quarter of 2006 and anticipate recording additional expenses of approximately $20 million for the remainder of 2006 based on these limits. For a further discussion of the impact of these hurricanes on our capital expenditures, see Capital Resources and Liquidity below.

Other Regulatory Matter. CIG anticipates filing a new rate case by June 30, 2006. In March 2006, the FERC granted CIG s request to change the effective date of its proposed new rates to no later than January 1, 2007. CIG is engaged in settlement discussions with its customers. The outcome of this rate case and its impact on revenues cannot be predicted with certainty at this time.

Exploration and Production Segment

Overview

Our Exploration and 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 manage this business with the goal of creating shareholder value through disciplined capital allocation, cost control and portfolio management. Our natural gas and oil reserve portfolio blends slower decline rate, typically longer lived assets in our Onshore region with steeper decline rate, shorter lived assets in our Texas Gulf Coast and Gulf of Mexico and south Louisiana regions. We believe the combination of our assets in these regions provides significant near-term cash flow while providing consistent opportunities for high-return investments.

Significant Operational Factors Since December 31, 2005

Higher realized prices. We continued to benefit from a strong commodity pricing environment in the first quarter of 2006. Realized natural gas prices, which include the impact of our hedges, increased 12 percent while oil, condensate and NGL prices increased 29 percent compared to the first quarter of 2005.

Average daily production of 694 MMcfe/d (excluding 71 MMcfe/d from our equity investment in Four Star). Our consolidated average daily equivalent production volumes were lower than expected due to continued shut-in production volumes in our Gulf of Mexico and south Louisiana region caused by hurricanes in the Gulf of Mexico during 2005. However, when including our proportionate share of production volumes from our equity investment in Four Star, average daily equivalent production volumes were level when compared with the first quarter 2005. Our production results by region are as follows:

Onshore. We have continued to increase production volumes as a result of our successful drilling and acquisition programs.

Gulf of Mexico and south Louisiana. In our Gulf of Mexico and south Louisiana region, production increased during the quarter as we continued to bring shut-in volumes from the hurricanes back on line. During the first quarter of 2006, the negative impact of shut-in volumes was approximately 40 MMcfe/d and at April 30, 2006, approximately 24 MMcfe/d remained shut-in, which we expect to bring back on line during the remainder of 2006.

Texas Gulf Coast First quarter of 2006 production volumes were 14 percent lower than the comparable period in 2005. However, our capital program in this region has stabilized production volumes over the last three quarters. In April 2006, we completed the sale of certain non-strategic south Texas natural gas and oil properties for $67 million. These properties had an average daily

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production of approximately 5 MMcfe/d and remaining reserves of approximately 13 Bcfe at the time of the sale.

Brazil. Average daily production volumes decreased to 32 MMcfe/d in 2006 from 59 MMcfe/d in 2005 due to a contractual reduction in our ownership interest from 79 percent to 35 percent in UnoPaso s production in the first quarter of 2006.

Capital expenditures. During the first quarter of 2006, our capital expenditures totaled $225 million.

Drilling results. Our drilling results by region in 2006 were as follows:

Onshore. We experienced a 100 percent success rate on 71 gross wells drilled resulting in production growth in the Rockies, Raton, north Louisiana and Arkoma operating areas.

Gulf of Mexico and south Louisiana. Overall, we experienced a 100 percent success rate on four gross wells drilled. We expect to bring our two deep shelf discovery wells at West Cameron Blocks 75 and 62 in the Gulf of Mexico on line in May 2006. We drilled our second Long Point well in Vermillion Parish, Louisiana in the first quarter of 2006. This well, along with the initial discovery well drilled in 2005, is expected to come on line during May 2006. The Long Point wells, in which we own a 25 percent working interest, tested at a combined rate of approximately 75 MMcfe/d.

Texas Gulf Coast. We experienced a 90 percent success rate on 10 gross wells drilled. Additional Wilcox production was established from exploration at the Renger Field in Lavaca County, Texas. The shallow Vicksburg development program in Starr and Hidalgo Counties, Texas continues to provide consistent results adding production on existing base properties.

International. In Brazil, we began two recompletions on wells in our Pescada-Arabaiana Field. We also filed our plan of development with Brazilian regulatory authorities on a 17-well development program in the Pinauna Field. In addition, we signed a rig contract and are preparing to drill two exploratory wells in the vicinity of the Pinuana Field scheduled for the second half of 2006.

In Egypt, El Paso was awarded the South Mariut Block for $3 million in April 2006, and agreed to a $22 million firm working commitment over three years. The block is about 1.1 million acres and is located onshore in the western part of the Nile Delta.

Outlook for 2006

For 2006, we anticipate the following:

Capital expenditures of approximately $775 million for the remainder of 2006;

Average daily production volumes for the year to average approximately 755 MMcfe/d to 780 MMcfe/d, which excludes approximately 70 MMcfe/d from our equity interest in Four Star;

Cash operating costs to average approximately $1.64/Mcfe to $1.71/Mcfe for the year;

Domestic unit of production depletion rate of $2.24/Mcfe in the second quarter of 2006 compared with $2.22/Mcfe in the first quarter of 2006;

Brazilian unit of production depletion rate of $1.98/Mcfe in the second quarter of 2006 compared with $1.96/Mcfe in the first quarter of 2006; and

Continued industry-wide increases in drilling and oilfield service costs that will require constant monitoring of capital spending programs and a mitigation effort designed to manage and improve field efficiency.

Production Hedge Position

We hedge our natural gas and oil production to stabilize cash flows, reduce the risk of downward commodity price movements on commodity sales and to protect the economic assumptions associated with

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our capital investment programs. Our hedge position includes average hedge prices that are significantly below the current market price for natural gas. Losses associated with our hedges, which are deferred in accumulated other comprehensive income, will be recognized upon the sale of the related production at market prices, resulting in a realized price that is approximately equal to the hedged price. For further information on our hedge contracts and the fair value of our commodity based derivatives, see Commodity Based Derivative Contracts below and our 2005 Annual Report on Form 10-K.

In April 2006, we entered into new derivative option contracts for a portion of our 2007 natural gas production. These option contracts, which were designated as accounting hedges, provide us with a floor price of $8.00 per MMBtu and an average ceiling price of $16.02 per MMBtu on 130 TBtu of our anticipated natural gas production in 2007. Additionally, we entered into basis swaps related to 5 TBtu of our anticipated south Texas natural gas production in 2006 and 37 TBtu in 2007, which were not designated as accounting hedges but rather will be marked-to-market in our results each period.

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Operating Results and Variance Analysis

The tables below and the discussion that follows provide the operating results and analysis of significant variances in these results during the quarters ended March 31:

	2006	2005
	(In millions)	
Operating Revenues:		
Natural gas	$ 366	$ 353
Oil, condensate and NGL	90	85
Other	10	1
Total operating revenues	466	439
Operating Expenses:		
Depreciation, depletion and amortization	(146)	(146)
Production costs[1]	(64)	(55)
Costs of products and services[2]	(22)	(13)
General and administrative expenses	(42)	(41)
Other	(1)	(4)
Total operating expenses	(275)	(259)
Operating income	191	180
Other income[3]	8	3
EBIT	$ 199	$ 183

	2006	Percent Variance	2005
Consolidated volumes, prices and costs per unit:			
Natural gas			
Volumes (MMcf)	52,029	(7)%	56,158
Average realized prices including hedges ($/Mcf)[4]	$ 7.03	12%	$ 6.28
Average realized prices excluding hedges ($/Mcf)[4]	$ 7.77	36%	$ 5.71
Average transportation costs ($/Mcf)	$ 0.24	33%	$ 0.18
Oil, condensate and NGL			
Volumes (MBbls)	1,745	(18)%	2,136
Average realized prices including hedges ($/Bbl)[4]	$ 51.25	29%	$ 39.86
Average realized prices excluding hedges ($/Bbl)[4]	$ 52.60	31%	$ 40.20
Average transportation costs ($/Bbl)	$ 1.25	67%	$ 0.75
Total equivalent volumes			
MMcfe	62,500	(9)%	68,976
MMcfe/d	694	(9)%	766
Production Costs ($/Mcfe)			
Average lease operating costs	$ 0.73	20%	$ 0.61

Average production taxes	0.29	53%	0.19
Total production cost[1]	$ 1.02	28%	$ 0.80
Average general and administrative cost ($/Mcfe)	$ 0.67	14%	$ 0.59
Unit of production depletion cost ($/Mcfe)	$ 2.20	10%	$ 2.00
Unconsolidated affiliate volumes (Four Star)[3]			
Natural gas (MMcf)	4,507		
Oil, condensate and NGL (MBbls)	309		
Total equivalent volumes			
MMcfe	6,360		
MMcfe/d	71		

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

(2) Includes transportation costs.

(3) Includes equity earnings and volumes for our investment in Four Star. Our equity interest in Four Star was acquired in connection with our acquisition of Medicine Bow in the third quarter 2005.

(4) Prices are stated before transportation costs.

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	Variance			
	Operating Revenue	Operating Expense	Other	EBIT
	Favorable/(Unfavorable) (In millions)			
Natural Gas Revenue				
Higher realized prices in 2006	$ 107	$	$	$ 107
Impact of hedges	(71)			(71)
Lower volumes in 2006	(23)			(23)
Oil, Condensate and NGL Revenue				
Higher realized prices in 2006	22			22
Impact of hedges	(1)			(1)
Lower volumes in 2006	(16)			(16)
Depreciation, Depletion and Amortization Expense				
Higher depletion rate in 2006		(13)		(13)
Lower production volumes in 2006		13		13
Production Costs				
Higher lease operating costs in 2006		(4)		(4)
Higher production taxes in 2006		(5)		(5)
General and Administrative Expenses		(1)		(1)
Other				
Earnings from investment in Four Star			7	7
Processing plants	9	(6)		3
Other			(2)	(2)
Total Variances	$ 27	$ (16)	$ 5	$ 16

Operating revenues. During the first quarter of 2006, we continued to benefit from a strong commodity pricing environment for natural gas and oil, condensate and NGL. However, losses in our hedging program for the quarter ended March 31, 2006 were $41 million compared to hedging gains of $31 million for the quarter ended March 31, 2005. Although our production volumes benefited from the acquisitions in 2005, overall production volumes decreased in our Texas Gulf Coast and Gulf of Mexico and south Louisiana regions which experienced declines in year over year production due to normal declines and a lower capital spending program in these areas over the last several years. In addition, our Gulf of Mexico and south Louisiana region production was also impacted by the hurricanes in 2005, while the Texas Gulf Coast region was impacted by mechanical well failures. Our production in Brazil decreased due to the contractual reduction in our ownership interest in UnoPaso.

Depreciation, depletion and amortization expense. During the first quarter of 2006, we experienced higher depletion rates compared to the first quarter of 2005 as a result of higher finding and development costs and the cost of acquired reserves, which resulted in higher depreciation, depletion and amortization expense. However, during the first quarter of 2006, the impact of lower production volumes offset the impact of our higher depletion rates.

Production costs. During the first quarter of 2006, our lease operating costs increased primarily due to higher maintenance, repair and workover costs as well as higher fuel and utility expenses compared to the first quarter of 2005. Additionally, production taxes increased as compared to the first quarter of 2005 as a result of higher commodity prices in the first quarter of 2006 and higher Brazilian production taxes. Partially offsetting these increases were higher tax credits taken during the first quarter of 2006 in Texas and Utah compared to the first quarter of 2005.

General and administrative expenses. Our general and administrative expenses remained relatively level during the first quarter of 2006 compared to the same period in 2005. While our labor related costs and corporate overhead allocations from El Paso decreased, we incurred higher environmental costs from our processing facilities and higher legal costs.

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Marketing and Trading Segment

Our Marketing and Trading segment s primary focus is to market our Exploration and Production segment s natural gas and oil production and to manage the company s overall price risks, primarily through the use of natural gas and oil derivative contracts. Historically, this segment has also managed a portfolio of power derivatives and contracts, as well as other structured commodity-based transactions. We continue to evaluate potential opportunities to assign or otherwise divest of a number of our contracts, including our legacy natural gas positions. Any future liquidations may impact our cash flows and financial results. For further discussion of our remaining contracts in this segment, see our 2005 Annual Report on Form 10-K.

Operating Results

The tables below and the discussion that follows provide the overall operating results and significant factors by contract type that affected the profitability of this segment during the quarters ended March 31:

	2006	2005
Overall EBIT:		
Gross margin[1]	$ 205	$ (175)
Operating expenses	(5)	(11)
Operating income (loss)	200	(186)
Other income, net[2]	8	1
EBIT	$ 208	$ (185)
Gross Margin by Significant Contract Type:		
Production-Related Natural Gas and Oil Derivative Contracts		
Changes in fair value of swaps and options	$ 162	$ (106)
Contracts Related to Legacy Trading Operations		
Natural gas contracts:		
Transportation-related contracts:		
Demand charges	(35)	(39)
Settlements	20	27
Changes in fair value of other natural gas derivative contracts	47	26
Power contracts:		
Change in fair value of power derivatives, excluding Cordova	11	(50)
Changes in fair value of Cordova tolling agreement		(33)
Total gross margin	$ 205	$ (175)

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

(2) Primarily represents interest on broker margin deposits.

Production-Related Natural Gas and Oil Derivative Contracts

Our production-related natural gas and oil derivative contracts consist of various swap and options contracts (floors and ceilings). The fair value of these contracts is impacted by changes in commodity prices from period to period. Decreases in commodity prices favorably impacted our EBIT in the first quarter of 2006, whereas increases in commodity prices negatively impacted our EBIT in the first quarter of 2005.

In April 2006, we entered into additional option contracts to reduce the volatility of our future earnings. These new contracts offset the price risk on certain existing mark-to-market positions that originally provided a floor of $6.00 per MMBtu on 30 TBtu and a floor of $7.00 per MMBtu and a ceiling of $9.00 per MMBtu on 21 TBtu in 2007. Additionally, we entered into basis swaps related to 6 TBtu on 2006 natural gas production,

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which were not designated as accounting hedges but rather will be marked-to-market in our results each period.

Contracts Related to Legacy Trading Operations

Natural Gas Contracts

Transportation-related contracts. During 2006, our ability to use contracted capacity under our transportation-related contracts decreased due to declining price differentials between the receipt and delivery points for these contracts. The following table is a summary of our demand charges (in millions) and our percentage of recovery of these charges for the quarters ended March 31:

	2006	2005
Alliance:		
Demand charges	$ 16	$ 16
Recovery	19%	65%
Enterprise Texas:		
Demand charges	$ 5	$ 7
Recovery	46%	67%
Other:		
Demand charges	$ 14	$ 16
Recovery	100%	73%

Other natural gas derivative contracts. Our exposure to the volatility of natural gas prices as it relates to our other natural gas derivative contracts varies from period to period based on whether we purchase more or less natural gas than we sell under these contracts. Because we had the right to purchase more natural gas at fixed prices than we had the obligation to sell under these contracts during the first quarter of 2005, the fair value of these contracts increased as natural gas prices increased during that period. For the same period in 2006, we recognized a $2 million loss on these contracts due to decreases in natural gas prices. However, in 2006 our EBIT was favorably impacted by a $49 million gain associated with the assignment to BG LNG Services, L.L.C. of contracts to supply natural gas to the Jacksonville Electric Authority and The City of Lakeland, Florida.

Under certain of these contracts, we supply gas to power plants that we partially own, including MCV and Berkshire power projects. Due to their affiliated nature, we do not recognize mark-to-market gains or losses on these contracts to the extent of our ownership interest. All amounts related to Berkshire are fully reserved as of March 31, 2006. However, should we sell our interest in the MCV plant, we would record the cumulative unrecognized mark-to-market losses on these contracts, which totaled approximately $132 million as of March 31, 2006.

Power Contracts

Through 2005, we divested or entered into transactions to divest of a substantial portion of our power contracts, including our (i) Cordova tolling agreement, (ii) substantially all contracts in our power portfolio and (iii) certain other contracts related to our Power segment s historical power contract restructuring business. As a result of these actions, our primary remaining exposure in our power portfolio is to locational differences in power prices between the Pennsylvania-New Jersey-Maryland (PJM) eastern region with those in the west PJM hub. The discussion that follows provides analysis of the impact of these contracts on our results for the quarters ended March 31, 2006 and 2005.

Power derivatives (excluding Cordova). We currently have derivative contracts with Constellation Energy Commodities Group, Inc. (Constellation) that swap the locational differences in power prices at several power plants in eastern PJM and the west PJM hub through 2013. The fair value of these contracts increased by $14 million in the first quarter of 2006 and decreased by $7 million in the first quarter of 2005 due to changes in regional power prices.

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Additionally, we supply power to Morgan Stanley under a power supply agreement related to our formerly-owned Utility Contract Funding (UCF) entity. We are also required to purchase power under a number of other power agreements, which include those used to manage our risk on the power supply obligation to Morgan Stanley. As a result of increasing power prices and increases in the differences in power prices at various locations in PJM, our Morgan Stanley power supply contract decreased in fair value by $90 million in the first quarter of 2005. This decrease was partially offset by a $47 million increase in the fair value of the power purchase contracts. In December 2005, we entered into an agreement to assign the majority of our remaining power portfolio to Morgan Stanley, which substantially eliminated our cash and earnings exposure to power price movements. This assignment includes all of our remaining power derivative contracts, except for the contracts with Constellation mentioned above and certain basis and installed capacity positions with Morgan Stanley in the PJM power pool that we retained. In the first quarter of 2006, these retained PJM basis and installed capacity positions decreased in value by $3 million.

Cordova tolling agreement. In the fourth quarter of 2005, we completed the assignment of this agreement to Constellation. Prior to this assignment, we experienced significant volatility under this agreement, with changes in forecasted natural gas and power prices. During the first quarter of 2005, forecasted natural gas prices increased relative to power prices, resulting in a decrease in the fair value of the contract.

Power Segment

As of March 31, 2006, our Power segment primarily consisted of international power assets in Brazil, Central America and Asia along with investments in three domestic power facilities. During the first quarter of 2006, our Board of Directors approved the sale of our interest in the Macae power project in Brazil, which we sold in April 2006. As a result, we reflected the financial results of Macae as discontinued operations for all periods presented. A discussion of our power activity is as follows:

Brazil

Porto Velho. Our Porto Velho project experienced an outage with its steam turbine in 2004, which resulted in a partial reduction in the plant s capacity. The steam turbine returned to service in the first quarter of 2006. The Porto Velho project is currently negotiating certain provisions of its power purchase agreement and the outcome of these negotiations, if resolved unfavorably, could adversely impact the value of our investment, which was $309 million as of March 31, 2006, including guarantees.

Araucaria. In early 2006, we signed a letter of intent to resolve the arbitration proceedings and to sell our investment in Araucaria of $188 million to COPEL for $190 million.

Other International Power

During 2005, we announced the sale of our Asian and Central American power assets. During the first quarter of 2005, we recorded impairments, net of gains on sales, of $60 million based on the value expected to be received upon closing the sales of our Asian assets. Additionally, we did not recognize earnings of approximately $8 million and $11 million on our Asian and Central American investments for the quarters ended March 31, 2006 and 2005 as we did not believe we would be able to realize earnings from these assets based on the expected value to be received.

In the third quarter of 2005, we completed the sale of our Korean power plant and in the first quarter of 2006, we completed the sale of our interests in our projects in Hungary, Peru and Bangladesh. The sale of those assets contributed to a reduction in earnings from our Asian and other international power assets in the first quarter of 2006 as compared with the same period in 2005. In April 2006, we completed the sales of our interests in both of our projects in Panama and the CEPP project in the Dominican Republic. We expect to substantially complete the sale of our remaining Asian and Central American power investments during the remainder of 2006 and will continue to monitor the fair value of these assets throughout the sales process until they are sold. See Item 1, Financial Statements, Note 3 for further information on our divestitures.

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Listed below is a further analysis of our results for the quarters ended March 31:

	2006	2005
	(In millions)	
EBIT by Area:		
Brazil		
EBIT from operations	$ 12	$ 12
Other International Power		
Asia		
Impairments related to anticipated sales		(82)
Gain on sale of PPN power plant		22
EBIT from operations	1	10
Central and other South America		
Impairments related to anticipated sales	(2)	
EBIT from operations	(1)	7
EBIT from other international plants and investments		1
Domestic Power		
Power contract restructuring[1]		11
Other	(6)	1
Other[2]	(1)	(21)
EBIT	$ 3	$ (39)

(1) As of December 31, 2005, we have sold our entire domestic contract restructuring business. In 2005, our results in this business were driven primarily by the change in the fair value of these contracts.

(2) Other consists of the indirect expenses and general and administrative costs associated with our domestic and international operations. It also includes a $15 million impairment of power turbines recorded in the first quarter of 2005.

Field Services Segment

As of January 1, 2006, we had divested of substantially all of the assets and operations in this segment. For the quarter ended March 31, 2005, our EBIT was primarily related to a gain of $183 million on the sale of our interest in Enterprise.

Corporate

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. The following items contributed to the decrease in our EBIT loss for the quarter ended March 31, 2006 as compared to the same period in 2005:

	Favorable (Unfavorable)
	(In millions)
Western Energy Settlement charge in 2005	$ 70
Higher losses on early extinguishment of debt in 2005	22

Change in litigation, insurance and other liabilities		(4)
Other		2
Total impact on EBIT	$	90

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 lawsuit and claim as to its merits and our defenses.

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Adverse rulings or unfavorable settlements against us related to these matters have impacted and may further impact our future results.

Income Taxes

Income taxes included in our income from continuing operations and our effective tax rates for the quarters ended March 31 were as follows:

	2006	2005
	(In millions, except for rates)	
Income taxes	$ 165	$ 1
Effective tax rate	31%	1%

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

Commitments and Contingencies

See Item 1, Financial Statements, Note 9, which is incorporated herein by reference.

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Capital Resources and Liquidity

Existing Financing Facilities. During the first quarter of 2006, debt activity was as follows (in millions):

Short-term financing obligations, including current maturities	$	986
Long-term financing obligations		17,023
Total debt as of December 31, 2005		18,009
Repayments/retirements of principal		(948)
Other		19
Total debt as of March 31, 2006	$	17,080

Available Liquidity. As of March 31, 2006, we had available liquidity as follows (in billions):

Available cash	$	1.6
Available capacity under our credit agreements(1)		0.4
Net available liquidity at March 31, 2006	$	2.0

(1) In May 2006, $0.3 billion of available borrowing capacity matured.

Expected 2006 Cash Flows. In addition to our available liquidity, we expect to generate significant operating cash flow in 2006, which we will supplement with approximately $1.0 billion of expected proceeds from asset sales, including proceeds from completing the assignment of our power derivative portfolio. We expect to also generate cash from financing activities as needed, including the anticipated issuance of common stock during the year. For the remainder of 2006, we expect to spend approximately $0.9 billion on capital investments in our core pipeline and $0.8 billion in our exploration and production businesses, intended to both maintain and grow these businesses.

As of March 31, 2006, we had debt maturities for the remainder of 2006 and for 2007 of approximately $0.6 billion and approximately $0.8 billion. Maturities for the remainder of 2006 include approximately $229 million related to Macae, repaid in April 2006 prior to closing the sale of the facility. In 2007, we also have approximately $600 million of debt that the holders can require us to redeem which, when combined with our maturities for that year, could require us to retire up to $1.4 billion of debt.

Significant Factors That Could Impact Our Liquidity.

Cash Margining Requirements on Derivative Contracts. A substantial portion of our natural gas and oil derivative contracts are at prices significantly below current market prices, which has resulted in us posting substantial cash margin deposits with the counterparties for the value of these instruments. During the first quarter of 2006, approximately $0.6 billion of posted cash margins were returned to us, with $0.3 billion resulting from decreases in commodity prices and settlement of certain of these contracts and an additional $0.3 billion related to the assignment of our power portfolio. For the remainder of 2006, based on current prices, we expect approximately $0.5 billion in collateral to be returned to us in the form of both cash margin deposits and letters of credit.

If commodity prices increase, we could be required to post additional margin. If prices decrease, we will be entitled to recover some of this amount earlier than anticipated. Based on our derivative positions at March 31, 2006, a $0.10/MMBtu increase in the price of natural gas would result in an increase in our margin requirements by $15 million for transactions that settle for the remainder of 2006, $6 million for transactions that settle in 2007, $5 million for transactions that settle in 2008 and $4 million for transactions that settle in 2009 and thereafter.

Hurricanes. We continue to assess the damage caused by Hurricanes Katrina and Rita. We are part of a mutual insurance company, and are subject to certain individual and aggregate loss limits by event. The mutual insurance company has indicated that the aggregate losses for both Hurricanes Katrina and Rita will exceed the per event limits allowed under the program, and that we will not receive insurance recoveries on some of the costs we incur, which will impact our liquidity and financial results. In addition, the timing of our replacements of the damaged property and equipment may differ from

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the related insurance reimbursement, which could impact our liquidity from period to period. Currently, we estimate that the total repair costs related to these hurricanes will be approximately $550 million, of which we estimate approximately $290 million will be unrecoverable from insurance. Of the unrecoverable amount, we estimate that approximately $230 million will be capital related expenditures, approximately $160 million of which we expect to incur in 2006.

Our mutual insurance company has also indicated that effective June 1, 2006, the aggregate loss limits on future events will be reduced to $500 million from $1 billion, which could further limit our recoveries on future hurricanes or other insurable events.

Price Risk Management Activities. As of March 31, 2006, our derivative contracts entered into to provide protection on a portion of our anticipated natural gas and oil production are substantially the same as those contracts described in our 2005 Annual Report on Form 10-K.

In April 2006, our Exploration and Production segment and Marketing and Trading segment entered into additional option contracts related to our 2007 natural gas production. Through a series of transactions, we (i) established a floor price of $8.00/MMBtu and an average ceiling price of $16.02/MMBtu on approximately 130 TBtu and (ii) offset the price risk associated with 21 TBtu of existing 2007 natural gas positions that had a floor price of $7.00/MMBtu and a ceiling price of $9.00/MMBtu and 30 TBtu that had a floor price of $6.00/MMBtu. These contracts will not require us to post any incremental net cash margin in the future. The options on the 130 TBtu are collateralized by certain natural gas and oil properties. We also entered into basis swaps on 11 TBtu of our anticipated south Texas natural gas production in 2006 and 37 TBtu in 2007. For additional information on these contracts, see our individual segment discussions.

We believe we will have sufficient liquidity to meet our ongoing liquidity and cash needs through a combination of available cash and borrowings under our credit agreements. For a further discussion of risks that may impact our cash flows, see our 2005 Annual Report on Form 10-K.

Overview of Cash Flow Activities for 2006 Compared to 2005

For the quarters ended March 31, 2006 and 2005, our cash flows are summarized as follows:

	2006	2005
	(In billions)	
Cash Flow from Operations		
Continuing operating activities		
Net income before discontinued operations	$ 0.4	$ 0.1
Non-cash income adjustments	0.4	0.3
Change in broker margin and other deposits(1)	0.6	0.1
Change in other assets and liabilities	(0.5)	(0.4)
Total cash flow from operations	$ 0.9	$ 0.1
Other Cash Inflows		
Continuing investing activities		
Net proceeds from the sale of assets and investments	$ 0.1	$ 0.6
Proceeds from settlement of a foreign currency derivative		0.1
Other		0.1
	0.1	0.8
Continuing financing activities		
Net proceeds from the issuance of long-term debt		0.2

Contribution from discontinued operations		0.1
		0.3
Total cash inflows	$ 1.0	$ 1.2

	2006	2005
	(In billions)	
Cash Outflows		
Continuing investing activities		
Capital expenditures[2]	$ 0.4	$ 0.4
Net cash paid for acquisition		0.2
	0.4	0.6
Continuing financing activities		
Payments to retire long-term debt and redeem preferred interests	0.9	1.0
Dividends and other	0.1	0.1
	1.0	1.1
Total other cash outflows	$ 1.4	$ 1.7
Net change in cash	$ (0.4)	$ (0.5)

(1) Primarily due to collection of $0.6 billion in margin calls in 2006 as commodity prices decreased and settlement of contracts.

(2) Includes $0.2 billion related to production, exploration and development projects and $0.2 billion related to pipeline expansion, maintenance and integrity projects for 2006.

Commodity-based Derivative Contracts

We use derivative financial instruments in our Exploration and Production and Marketing and Trading segments to manage the price risk of commodities. In the tables below, derivatives designated as hedges consist of instruments used to hedge our natural gas and oil production. Other commodity-based derivative contracts relate to derivative contracts not designated as hedges, such as options, swaps and other natural gas and power purchase and supply contracts as well as contracts related to our historical energy trading activities. The table below details the maturity of these contracts as of March 31, 2006.

	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	$ 14	$	$	$	$	$ 14
Liabilities	(269)	(54)	(31)	(12)		(366)
Total derivatives designated as hedges	(255)	(54)	(31)	(12)		(352)

Other commodity-based derivatives						
Exchange-traded positions[1]						
Assets	114	313	120			547
Non-exchange-traded positions						
Assets	174	383	180	102	14	853
Liabilities	(387)	(811)	(419)	(322)	(10)	(1,949)
Total other commodity-based derivatives	(99)	(115)	(119)	(220)	4	(549)
Total commodity-based derivatives	$ (354)	$ (169)	$ (150)	$ (232)	$ 4	$ (901)

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

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Below is a reconciliation of our commodity-based derivatives for the period from January 1, 2006 to March 31, 2006:

	Derivatives Designated as Hedges	Other Commodity-Based Derivatives	Total Commodity-Based Derivatives
		(In millions)	
Fair value of contracts outstanding at January 1, 2006	$ (653)	$ (763)	$ (1,416)
Fair value of contract settlements during the period	101	(5)	96
Change in fair value of contracts	200	219[(1)]	419
Net change in contracts outstanding during the period	301	214	515
Fair value of contracts outstanding at March 31, 2006	$ (352)	$ (549)	$ (901)

[(1)] Includes a $49 million gain associated with the assignment to BG LNG Services, L.L.C. of contracts to supply natural gas to the Jacksonville Electric Authority and The City of Lakeland, Florida.

Fair Value of Contract Settlements. 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.

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

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

This information updates, and you should read it in conjunction with, information disclosed in our 2005 Annual Report on Form 10-K 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 2005 Annual Report on Form 10-K 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 from our Marketing and Trading segment s commodity and energy-related contracts on a daily basis with a Value-at-Risk model using a historical simulation technique with a confidence level of 95 percent and a one-day holding period. Our Value-at-Risk simulations do not include exposure to commodity prices of our Exploration and Production segment. Our Value-at-Risk, which represents our potential one-day unfavorable impact on the fair values of our commodity and energy-related contracts, was $30 million as of March 31, 2006 and $60 million as of December 31, 2005 for contracts accounted for under accrual-based or mark-to-market accounting. Comparatively, our Value-at-Risk for only those contracts accounted for under mark-to-market accounting was $24 million as of March 31, 2006 and $45 million as of December 31, 2005. The decline was primarily the result of the reduction in natural gas prices. We may experience significant changes in our Value-at-Risk in the future if commodity prices continue to be volatile.

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Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of March 31, 2006, 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 by the Securities Exchange Act of 1934, as amended. 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 accurate, complete and timely.

Based on the results of this evaluation, our CEO and CFO concluded that our disclosure controls and procedures were effective as of March 31, 2006.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that have materially affected or are reasonably likely to materially affect our internal control over financial reporting during the first quarter 2006.

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PART II   OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Note 9, which is incorporated herein by reference. Additional information about our legal proceedings can be found below and in Part I, Item 3 of our 2005 Annual Report on Form 10-K filed with the SEC.

Environmental Proceedings

Air Permit Violation. In March 2003, the Louisiana Department of Environmental Quality (LDEQ) issued a Consolidated Compliance Order and Notice of Potential Penalty to our subsidiary, El Paso Production Company, alleging that it failed to timely obtain air permits for specified oil and natural gas facilities. El Paso Production Company requested an adjudicatory hearing on the matter. Pursuant to discussions with LDEQ, we reached an agreement to resolve the allegations and paid $77,287 on March 17, 2006.

Arizona Pipe Coating. In September 2005, the Arizona Department of Environmental Quality (ADEQ) issued a Notice of Violation (NOV) for alleged regulatory violations related to our handling of asbestos-containing coal tar enamel coating. This matter was referred to the Office of the Attorney General for the State of Arizona and we have agreed in principle to settle this matter for $225,000.

Tucson Waste Management. In September 2004, we received a NOV from the ADEQ for an alleged failure to comply with waste management regulations at EPNG s Tucson compressor station. This matter was referred to the Attorney General for the State of Arizona and we have agreed in principle to settle this matter for $115,000.

Item 1A. Risk Factors

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.

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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 2005 Annual Report on Form 10-K. There have been no material changes in our risk factors since that report.

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.

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Item 6. Exhibits

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

Exhibit Number	Description
*12	Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends.
*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 SEC, 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.

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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 5, 2006

/s/ D. Mark Leland

D. Mark Leland
Executive Vice President and
Chief Financial Officer
(Principal Financial Officer)

Date: May 5, 2006

/s/ John R. Sult

John R. Sult
Senior Vice President and Controller
(Principal Accounting Officer)

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EL PASO CORPORATION
EXHIBIT INDEX

Each exhibit identified below is a part of this Report. Exhibits filed with this Report are designated by * . All exhibits not so designated are incorporated herein by reference to a prior filing as indicated.

Exhibit Number	Description
*12	Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends.
*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.