EL PASO CORP/DE
Form 10-Q
May 09, 2008

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

Form 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2008

OR

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

Telephone Number: (713) 420-2600
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, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ Accelerated filer o Non-accelerated filer o (Do not check if a smaller reporting company) Smaller reporting company 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 6, 2008: 702,325,215

EL PASO CORPORATION
TABLE OF CONTENTS

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

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

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

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

Table of Contents

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, 2008	Quarter Ended March 31, 2007
Operating revenues	$ 1,269	$ 1,022
Operating expenses		
Cost of products and services	56	55
Operation and maintenance	271	301
Depreciation, depletion and amortization	313	271
Taxes, other than income taxes	79	60
	719	687
Operating income	550	335
Earnings from unconsolidated affiliates	37	37
Loss on debt extinguishment		(201)
Other income, net	22	46
Minority interest	(9)	(1)
Interest and debt expense	(233)	(283)
Income (loss) before income taxes from continuing operations	367	(67)
Income taxes	148	(19)
Income (loss) from continuing operations	219	(48)
Discontinued operations, net of income taxes		677
Net income	219	629
Preferred stock dividends	19	9
Net income available to common stockholders	$ 200	$ 620
Basic and diluted earnings per common share		
Income (loss) from continuing operations	$ 0.29	$ (0.08)
Discontinued operations, net of income taxes		0.97
Net income per common share	$ 0.29	$ 0.89
Dividends declared per common share	$ 0.08	$ 0.04

See accompanying notes.

Table of Contents

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

	March 31, 2008	December 31, 2007
ASSETS		
Current assets		
Cash and cash equivalents	$ 498	$ 285
Accounts and notes receivable		
Customers, net of allowance of $17 in 2008 and 2007	691	468
Affiliates	150	196
Other	172	201
Inventory	132	131
Assets from price risk management activities	45	113
Deferred income taxes	285	191
Other	155	127
Total current assets	2,128	1,712
Property, plant and equipment, at cost		
Pipelines	16,925	16,750
Natural gas and oil properties, at full cost	18,616	19,048
Other	307	530
	35,848	36,328
Less accumulated depreciation, depletion and amortization	17,071	16,974
Total property, plant and equipment, net	18,777	19,354
Other assets		
Investments in unconsolidated affiliates	1,846	1,614
Assets from price risk management activities	326	302
Other	1,589	1,597
	3,761	3,513
Total assets	$ 24,666	$ 24,579

See accompanying notes.

Table of Contents

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

	March 31, 2008	December 31, 2007
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 445	$ 460
Affiliates	9	5
Other	432	502
Current maturities of long-term financing obligations	366	331
Liabilities from price risk management activities	440	267
Accrued interest	230	195
Other	748	653
Total current liabilities	2,670	2,413
Long-term financing obligations, less current maturities	12,322	12,483
Other		
Liabilities from price risk management activities	896	931
Deferred income taxes	1,337	1,157
Other	1,565	1,750
	3,798	3,838
Commitments and contingencies (Note 8)		
Minority interest	547	565
Stockholders equity		
Preferred stock, par value $0.01 per share; authorized 50,000,000 shares; issued 750,000 shares of 4.99% convertible perpetual stock; stated at liquidation value	750	750
Common stock, par value $3 per share; authorized 1,500,000,000 shares; issued 709,548,833 shares in 2008 and 709,192,605 shares in 2007	2,129	2,128
Additional paid-in capital	4,639	4,699
Accumulated deficit	(1,610)	(1,834)
Accumulated other comprehensive loss	(387)	(272)
Treasury stock (at cost); 8,699,603 shares in 2008 and 8,656,095 shares in 2007	(192)	(191)
Total stockholders equity	5,329	5,280
Total liabilities and stockholders equity	$ 24,666	$ 24,579

See accompanying notes.

Table of Contents

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

	Quarter Ended March 31, 2008	Quarter Ended March 31, 2007
Cash flows from operating activities		
Net income	$ 219	$ 629
Less income from discontinued operations, net of income taxes		677
Income (loss) from continuing operations	219	(48)
Adjustments to reconcile net income to net cash from operating activities		
Depreciation, depletion and amortization	313	271
Deferred income tax expense (benefit)	146	(18)
Earnings from unconsolidated affiliates, adjusted for cash distributions	23	37
Loss on debt extinguishment		201
Other non-cash income items	15	(2)
Asset and liability changes	(82)	(93)
Cash provided by continuing activities	634	348
Cash used in discontinued activities		(35)
Net cash provided by operating activities	634	313
Cash flows from investing activities		
Capital expenditures	(531)	(528)
Cash paid for acquisitions	(295)	(255)
Net proceeds from the sale of assets and investments	598	38
Other	37	2
Cash used in continuing activities	(191)	(743)
Cash provided by discontinued activities		3,678
Net cash provided by (used in) investing activities	(191)	2,935
Cash flows from financing activities		
Net proceeds from issuance of long-term debt	1,240	1,424
Payments to retire long-term debt and other financing obligations	(1,430)	(4,654)
Dividends paid	(38)	(37)
Contributions from discontinued operations		3,360
Other	(2)	(3)
Cash provided by (used in) continuing activities	(230)	90
Cash used in discontinued activities		(3,643)

Net cash used in financing activities	(230)	(3,553)
Change in cash and cash equivalents	213	(305)
Cash and cash equivalents		
Beginning of period	285	537
End of period	$ 498	$ 232

See accompanying notes.

6

Table of Contents

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

	Quarter Ended March 31,	
	2008	**2007**
Net income	$ 219	$ 629
Pension and postretirement obligations:		
Unrealized actuarial losses arising during period (net of income taxes of $1 in 2008)	(2)	
Reclassification adjustments (net of income taxes of $2 in 2008 and $3 in 2007)	5	6
Cash flow hedging activities:		
Unrealized mark-to-market losses arising during period (net of income taxes of $70 in 2008 and $47 in 2007)	(123)	(83)
Reclassification adjustments for changes in initial value to the settlement date (net of income taxes of $1 in 2008 and $15 in 2007)	2	(25)
Investments available for sale:		
Unrealized gains on investments available for sale arising during period (net of income taxes of $2 in 2007)		3
Other comprehensive loss	(118)	(99)
Comprehensive income	$ 101	$ 530

See accompanying notes.

Table of Contents

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 (SEC). Because this is an interim period filing presented using a condensed format, it does not include all of the disclosures required by U.S. generally accepted accounting principles. You should read this Quarterly Report on Form 10-Q along with our 2007 Annual Report on Form 10-K, which contains a summary of our significant accounting policies and other disclosures. The financial statements as of March 31, 2008, and for the quarters ended March 31, 2008 and 2007, are unaudited. We derived the condensed consolidated balance sheet as of December 31, 2007, from the audited balance sheet filed in our 2007 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 operating results for the entire year. 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

The information below provides an update of our significant accounting policies and accounting pronouncements issued but not yet adopted as discussed in our 2007 Annual Report on Form 10-K.

Fair Value Measurements. On January 1, 2008, we adopted the provisions of Statement of Financial Accounting Standards (SFAS) No. 157, *Fair Value Measurements*, for our financial assets and liabilities. We elected to defer the adoption of SFAS No. 157 for our non-financial assets and liabilities until January 1, 2009. The impact of adopting SFAS No. 157 was both a pre-tax increase to operating revenues of $6 million and to other comprehensive income of $4 million, and a reduction of our liabilities of $10 million, which represented the impact of the consideration of our credit standing in determining the value of our price risk management liabilities.

Measurement Date of Postretirement Benefits. Effective January 1, 2008, we adopted the measurement date provisions of SFAS No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an Amendment of FASB Statements No. 87, 88, 106, and 132(R)* and changed the measurement date of our postretirement benefit plans from September 30 to December 31. We recorded a $5 million decrease, net of income taxes of $2 million, to the January 1, 2008 accumulated deficit and a $3 million decrease, net of income taxes of $2 million, to the January 1, 2008 accumulated other comprehensive loss upon the adoption of the measurement date provisions of this standard to reflect an additional three months of net periodic benefit cost based on our September 30, 2007 measurement.

Derivative Instruments. In March 2008, the Financial Accounting Standards Board (FASB) issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133*, which requires expanded disclosures about derivative instruments. This standard requires companies to disclose their purpose for using derivative instruments, how those derivatives are accounted for under SFAS No. 133, and where the impacts of those derivatives are reflected in the financial statements. The provisions of this standard are effective for fiscal years beginning after November 15, 2008, and we are currently evaluating the impact that the adoption of this standard will have on our financial statement disclosures.

2. Acquisitions and Divestitures

Acquisitions

Gulf LNG. In February 2008, we paid $295 million to complete the acquisition of a 50 percent interest in the Gulf LNG Clean Energy Project, an LNG terminal which is currently under construction in Pascagoula, Mississippi. The terminal is expected to be placed in service in late 2011 at an estimated total cost of $1.1 billion. In addition, we have a commitment to loan Gulf LNG up to $150 million under which we had advanced $1 million as of March 31, 2008. Our partner in this project has commitment to loan up to $64 million. We account for our investment in Gulf LNG using the equity method.

South Texas properties. In January 2007, we acquired operated natural gas and oil producing properties and undeveloped acreage in south Texas for approximately $254 million.

Divestitures

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 to be disposed of by our management or Board of Directors and when they meet other criteria. Cash flows from our discontinued businesses are reflected as discontinued operating, investing, and financing activities in our statement of cash flows. To the extent these operations do not maintain separate cash balances, we reflect the net cash flows generated from these businesses as a contribution to our continuing operations in cash from continuing financing activities.

Continuing operations asset sales. During the first quarter of 2008, we completed the sale of certain non-core Gulf of Mexico, Onshore and Texas Gulf Coast natural gas and oil properties for net cash proceeds of approximately $600 million.

Discontinued Operations. The following is a description of our discontinued operations and summarized results of these operations for the quarter ended March 31, 2007. As of March 31, 2008, all our assets and liabilities related to our discontinued operations and assets held for sale had been sold.

In February 2007, we sold ANR, our Michigan storage assets and our 50 percent interest in Great Lakes Gas Transmission for approximately $3.7 billion. During the first quarter of 2007, we recorded a gain on the sale of $651 million, net of taxes of $356 million. Included in the net assets of these discontinued operations as of the date of sale were net deferred tax liabilities assumed by the purchaser. Below is summarized income statement information regarding our discontinued operations:

	ANR and Related Operations (In millions)
Quarter Ended March 31, 2007	
Revenues	$ 101
Costs and expenses	(43)
Other expense	(7)
Interest and debt expense	(10)
Income taxes	(15)
Income from operations	26
Gain on sale, net of income taxes of $356 million	651
Net income from discontinued operations	$ 677

Table of Contents

3. Income Taxes

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

	2008	2007
	(In millions, except rates)	
Income taxes	$148	$(19)
Effective tax rate	40%	28%

We compute interim period income taxes by applying an anticipated annual effective tax rate to our year-to-date income or loss, except for significant unusual or infrequently occurring items. Significant tax items are recorded in the period that the item occurs.

During the first quarter of 2008, our effective tax rate was higher than the statutory rate primarily due to the tax impact of adjusting our postretirement benefit obligations (See Note 9). During the first quarter of 2007, our overall effective tax rate on continuing operations was lower than the statutory rate of 35 percent primarily due to earnings from unconsolidated affiliates where we anticipate receiving dividends and state income taxes (net of federal tax benefit) .

4. Earnings Per Share

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

	2008 [1]		2007	
	Basic	Diluted	Basic	Diluted
	(In millions, except per share amounts)			
Income (loss) from continuing operations	$ 219	$ 219	$ (48)	$ (48)
Convertible preferred stock dividends	(19)[1]	(19)[1]	(9)	(9)
Income (loss) from continuing operations available to common stockholders	200	200	(57)	(57)
Discontinued operations, net of income taxes			677	677
Net income available to common stockholders	$ 200	$ 200	$ 620	$ 620
Weighted average common shares outstanding	697	697	694	694
Effect of dilutive securities:				
Options and restricted stock		4		
Weighted average common shares outstanding and dilutive securities	697	701	694	694
Earnings per common share:				
Income (loss) from continuing operations	$ 0.29	$ 0.29	$ (0.08)	$ (0.08)
Discontinued operations, net of income taxes			0.97	0.97
Net income	$ 0.29	$ 0.29	$ 0.89	$ 0.89

(1) Includes dividends declared in February 2008 and March 2008 (see Note 10).

We exclude potentially dilutive securities (such as employee stock options, restricted stock, convertible preferred stock and trust preferred securities) from the determination of diluted earnings per share when their impact on income from continuing operations per common share is antidilutive. For the quarter ended March 31, 2008, certain of our employee stock options, our convertible preferred stock, and our trust preferred securities were antidilutive. For the quarter ended March 31, 2007, we incurred losses from continuing operations and accordingly excluded all of our potentially dilutive securities from the determination of diluted earnings per share as their impact on loss per common share was antidilutive. For a further discussion of our potentially dilutive securities, see our 2007 Annual Report on Form 10-K.

Table of Contents

5. Fair Value Measurements

On January 1, 2008, we adopted the provisions of SFAS No. 157, *Fair Value Measurements*, and SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*, for our financial assets and liabilities. SFAS No. 157 expands the disclosure requirements for financial instruments and other derivatives recorded at fair value, and also requires that a company s own credit risk be considered in determining the fair value of those instruments. The adoption of SFAS No. 157 resulted in a $6 million increase in operating revenues, a $4 million pre-tax increase in other comprehensive income, and a $10 million reduction of our liabilities to reflect the consideration of our credit risk on our liabilities that are recorded at fair value. SFAS No. 159 provided us the option to record most financial assets and liabilities at fair value on an instrument-by-instrument basis with changes in their fair value reported through the income statement. The adoption of SFAS No. 159 had no impact on our financial statements as we elected not to adopt fair value accounting at the present time for our applicable financial assets and liabilities.

We use various methods to determine the fair values of our financial instruments and other derivatives which depend on a number of factors, including the availability of observable market data over the contractual term of the underlying instrument. For some of our instruments, the fair value is calculated based on directly observable market data or data available for similar instruments in similar markets. For other instruments, the fair value may be calculated based on these inputs as well as other assumptions related to estimates of future settlements of these instruments. We separate our financial instruments and other derivatives into three levels (Levels 1, 2 and 3) based on our assessment of the availability of observable market data and the significance of non-observable data used to determine the fair value of our instruments. Our assessment of an instrument can change over time based on the maturity or liquidity of the instrument, which could result in a change in the classification of the instruments between levels. Each of these levels and our corresponding instruments classified by level are further described below:

Level 1 instruments fair values are based on quoted prices in actively traded markets. Included in this level are our marketable securities invested in non-qualified compensation plans whose fair value is determined using quoted prices of these instruments.

Level 2 instruments fair values are based on pricing data representative of quoted prices for similar assets and liabilities in active markets (or identical assets and liabilities in less active markets). Included in this level are our production-related natural gas and oil derivatives and certain of our other natural gas derivatives (such as natural gas supply arrangements) whose fair values are based on commodity pricing data obtained from an independent pricing source.

Level 3 instruments fair values are partially calculated using pricing data that is similar to Level 2 above, but their fair value also reflects adjustments for being in less liquid markets or having longer contractual terms. For these instruments, we use available pricing data adjusted for liquidity and/or contractual terms to develop an estimate of forward price curves. The curves are then used to estimate the value of settlements in future periods based on contractual settlement quantities and dates. Our valuation of these instruments considers specific contractual terms, statistical and simulation analysis, present value concepts and other internal assumptions related to (i) contract maturities that extend beyond the periods in which quoted market prices are available; (ii) the uniqueness of the contract terms and (iii) the lack of viable market participants. Since a significant portion of the fair value of our power-related derivatives, interest rate and foreign currency swaps and certain of our remaining natural gas derivatives with longer terms or in less liquid markets than similar Level 2 derivatives, rely on the techniques discussed above, we classify these instruments as Level 3 instruments.

Listed below are our financial instruments classified in each level and a description of the significant inputs utilized to determine their fair value at March 31, 2008 follows (in millions):

	Level 1	Level 2	Level 3	Total
Assets				
Marketable securities invested in non-qualified compensation plans	$ 20	$	$	$ 20

Production-related natural gas and oil derivatives		3		3
Other natural gas derivatives		36	34	70
Power-related derivatives			127	127
Interest rate and foreign currency swaps			171	171
Total assets	20	39	332	391

Table of Contents

	Level 1	Level 2	Level 3	Total
Liabilities				
Production-related natural gas and oil derivatives		(302)		(302)
Other natural gas derivatives		(192)	(217)	(409)
Power-related derivatives			(612)	(612)
Interest rate swaps		(13)		(13)
Other			(84)	(84)
Total liabilities		(507)	(913)	(1,420)
Total	$ 20	$ (468)	$ (581)	$ (1,029)

The following table presents the changes in our financial assets and liabilities included in Level 3 for the quarter ended March 31, 2008 (in millions):

	Balance as of January 1, 2008	Change in fair value reflected in operating revenues(1)	Change in fair value reflected in operating expenses(2)	Change in fair value reflected in long-term financing obligations(3)	Settlements, Net	Balance as of March 31, 2008
Assets	$ 250	$ 32	$	$ 59	$ (9)	$ 332
Liabilities	(839)	(70)	(44)		40	(913)
Total	$ (589)	$ (38)	$ (44)	$ 59	$ 31	$ (581)

(1) Includes approximately $37 million of net losses that had not been realized through settlements as of March 31, 2008.
(2) Includes approximately $43 million of net losses that had not been realized through settlements as of March 31, 2008.
(3) Includes approximately $59 million of net gains that had not been realized through settlements as of March 31, 2008.

6. Price Risk Management Activities

The following table summarizes the carrying value of the derivatives used in our price risk management activities. In the table below, derivatives designated as accounting 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 accounting hedges, such as options and swaps, other natural gas and power purchase and supply contracts, and derivatives related to our legacy energy trading activities. Interest rate and foreign currency derivatives consist of swaps that are primarily designated as hedges of our interest rate and foreign currency risk on long-term debt.

	March 31,	December 31,

	2008	2007
	(In millions)	
Net assets (liabilities):		
Derivatives designated as accounting hedges	$ (214)	$ (23)
Other commodity-based derivative contracts	(909)	(869)
Total commodity-based derivatives	(1,123)	(892)
Interest rate and foreign currency derivatives	158	109
Net liabilities from price risk management activities[1]	$ (965)	$ (783)

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

7. Long-Term Financing Obligations and Other Credit Facilities

	March 31, 2008	December 31, 2007
	(In millions)	
Current maturities of long-term financing obligations	$ 366	$ 331
Long-term financing obligations	12,322	12,483
Total	$ 12,688	$ 12,814

Credit Facilities. As of March 31, 2008, we had available capacity under various credit agreements of approximately $1.2 billion. During the first quarter of 2008, we made net repayments of $150 million under our $1.5 billion revolving credit facility and as of March 31, 2008 had approximately $0.3 billion of letters of credit issued and approximately $0.3 billion of debt outstanding under this facility. Additionally, as of March 31, 2008, (i) substantially all of the $1 billion of capacity under our various unsecured revolving credit facilities was used to issue letters of credit and (ii) approximately $ 0.7 billion was outstanding under our El Paso Exploration & Production Company (EPEP) $1.0 billion revolving credit facility.

During the first quarter of 2008, El Paso Pipeline Partners, L.P. (EPB) borrowed an additional $40 million, increasing the total amount outstanding under the facility to $495 million as of March 31, 2008. The EPB borrowings are not recourse to El Paso and the facility is solely available for use by EPB and its subsidiaries.

Letters of Credit. We enter into letters of credit in the ordinary course of our operating activities as well as periodically in conjunction with the sales of assets or businesses. As of March 31, 2008, we had outstanding letters of credit of approximately $1.3 billion. Included in this amount is approximately $1.0 billion of letters of credit securing our recorded obligations related to price risk management activities.

8. Commitments and Contingencies

Legal Proceedings

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 that our communication with participants in our Retirement Savings Plan included various 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). Various motions have been filed and we are awaiting the court s ruling. We have insurance coverage for this lawsuit, subject to certain deductibles and co-pay obligations. We have established accruals for this matter 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 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. The claims that our cash balance plan violated ERISA were recently dismissed by the trial court. Our costs and legal exposure related to this lawsuit are not currently determinable.

Retiree Medical Benefits Matter. We serve as the plan administrator for a medical benefits plan that covers a closed group of retirees of Case Corporation who retired on or before July 1, 1994. Case was formerly a subsidiary of Tenneco, Inc. that was spun off in 1994. Tenneco retained an obligation to provide certain medical benefits at the time of the spin-off and we assumed this obligation as a result of our merger with Tenneco. Pursuant to an agreement with the applicable union for Case employees, we believed our liability for these benefits was subject to a cap, such that costs in excess of the cap were to be assumed by plan participants. In 2002, we and Case were sued by individual retirees in a federal court in Detroit, Michigan in an action entitled *Yolton et al. v. El Paso Tennessee Pipeline Co. and Case Corporation.* The suit alleged, among other things, that El Paso and Case violated ERISA, that the benefits are vested under the applicable collective bargaining agreements and that the defendants should be required to pay all costs above the cap. Case further filed claims against El Paso asserting that El Paso was obligated to indemnify Case for the amounts it would be required to pay. Prior to 2008, we accrued amounts pursuant to various court rulings requiring us to indemnify Case for these above the cap amounts, pending a trial on the merits.

In the first quarter of 2008, the trial court granted summary judgment and ruled that the benefits are vested. The effect of this ruling is that we became the primary party that is obligated to pay for amounts above the cap. As a result of the ruling, we adjusted our existing indemnification accrual using current actuarial assumptions and reclassified our liability as a postretirement benefit obligation. See Note 9 for a discussion of the impact of this matter on our postretirement benefit obligations. Additionally, we intend to pursue appellate options following the determination by the trial court of any damages incurred by the plaintiffs during the period when premium payments for the above the cap costs were paid by the retirees. We believe our accruals established for this matter are adequate.

Price Reporting Litigation. Beginning in 2003, several lawsuits were filed against El Paso Marketing L.P. (EPM) alleging 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 set of cases, involving similar allegations on behalf of commercial and residential customers, was transferred to a multi-district litigation proceeding (MDL) in the U.S. District Court for Nevada and styled In re: Western States Wholesale Natural Gas Antitrust Litigation. These cases were dismissed. The U.S. Court of Appeals for the Ninth Circuit, however, reversed the dismissal and ordered that these cases be remanded to the trial court. The second set of cases also involve similar allegations on behalf of certain purchasers of natural gas. These include Farmland Industries v. Oneok Inc., et al. (filed in state court in Wyandotte County, Kansas in July 2005) and Missouri Public Service Commission v. El Paso Corporation, et al. (filed in the circuit court of Jackson County, Missouri at Kansas City in October 2006), and the purported class action lawsuits styled: Leggett, et al. v. Duke Energy Corporation, et al. (filed in Chancery Court of Tennessee in January 2005); Ever-Bloom Inc., et al. v. AEP Energy Services Inc., et al. (filed in federal court for the Eastern District of California in September 2005); Learjet, Inc., et al. v. Oneok Inc., et al. (filed in state court in Wyandotte County, Kansas in September 2005); Breckenridge, et al. v. Oneok Inc., et al. (filed in state court in Denver County, Colorado in May 2006); Arandell, et al. v. Xcel Energy, et al. (filed in the circuit court of Dane County, Wisconsin in December 2006); and Heartland, et al. v. Oneok Inc., et al. (filed in the circuit court of Buchanan County, Missouri in March 2007). The Leggett case was dismissed by the Tennessee state court and has been appealed. The Missouri Public Service case was remanded to state court. The Breckenridge case has been dismissed, but a motion for reconsideration was filed. The remaining cases have all been transferred to the MDL proceeding. Dispositive motions have been filed or are anticipated to be filed in these cases. 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 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 have 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 October 2006, the U.S. District Judge issued an order dismissing all claims against all defendants. An appeal has been filed.

Similar allegations were filed in a second set of actions initiated in 1999 in *Will Price, et al. v. Gas Pipelines and Their Predecessors, et al.,* in the District Court of Stevens County, Kansas. The plaintiffs currently seek certification of a class of royalty owners in wells on non-federal and non-Native American lands 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. The 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.

MTBE. Certain of our subsidiaries used the gasoline additive methyl tertiary-butyl ether (MTBE) in some of their gasoline. Certain subsidiaries also produced, bought, sold and distributed MTBE. A number of lawsuits have been filed throughout the U.S. regarding the potential impact of MTBE on water supplies. Some of our subsidiaries are among the defendants in approximately 81 such lawsuits. The plaintiffs, certain state attorneys general, various water districts and a limited number of individual water customers, generally seek remediation of their groundwater, prevention of future contamination, damages (including natural resource damages), punitive damages, attorney s fees and court costs. 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. Although these suits had been consolidated for pre-trial purposes in multi-district litigation in the U.S. District Court for the Southern District of New York, an appellate court decision directed two of the cases to be remanded back to state court. A limited number of cases have since been remanded to separate state court proceedings. It is possible many of the other cases will also be remanded. We have reached an agreement in principle with the plaintiffs to settle approximately 59 of the lawsuits. We have also reached an agreement in principle with our insurers, whereby our insurers would fund substantially all of the consideration to be provided by our subsidiaries under the terms of the settlement with the plaintiffs. Approximately 22 of the remaining lawsuits are not covered by the terms of this settlement. While the damages claimed in these remaining actions are substantial, there remains significant legal uncertainty regarding the validity of the causes of action asserted and the availability of the relief sought by the plaintiffs. We have tendered these remaining cases to our insurers. Our costs and legal exposure related to these remaining 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 originally self-reported this matter to the SEC and have cooperated with the SEC in its investigation. On July 13, 2007, we received a notice indicating the SEC staff has made a preliminary decision to recommend to the SEC that it institute an enforcement action against us and two of our subsidiaries related to the reserve revisions. We understand that the staff of the SEC may have also issued similar notices to several of our former employees. We were given the opportunity to respond to the staff before it makes its formal recommendation on whether any action should be brought by the SEC, and on September 25, 2007 we submitted our response.

In addition to the above proceedings, 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 these 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, including those 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. It is possible, however, 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, 2008, we had approximately $147 million accrued, which has not been reduced by $33 million of related insurance receivables, for outstanding legal and governmental proceedings.

Rates and Regulatory Matters

Notice of Inquiry on Pipeline Fuel Retention Policies. In September 2007, the Federal Energy Regulatory Commission (FERC) issued a Notice of Inquiry regarding its policy about the in-kind recovery of fuel and lost and unaccounted for gas by natural gas pipeline companies. Under current policy, pipelines have options for recovering these costs. For some pipelines, the tariff states the recovery of a fixed percentage as a non-negotiable fee-in-kind retained from the volumes tendered for shipment by each shipper. There is also a tracker approach, where the pipeline s tariff provides for prospective adjustments to the fuel retention rates from time-to-time, but does not include a mechanism to allow the pipeline to reconcile past over or under-recoveries of fuel. Finally, some pipelines tariffs provide for a tracker with a true-up approach, where provisions in a pipeline s tariff allow for periodic adjustments to the fuel retention rates, and also provide for a true-up of past over and under-recoveries of fuel and lost and unaccounted for gas. In this proceeding, the FERC is seeking comments on whether it should change its current policy and prescribe a uniform method for all pipelines to use in recovering these costs. Our pipeline subsidiaries currently utilize a variety of these methodologies. At this time, we do not know what impact, if any, this proceeding may ultimately have on any of us.

Notice of Proposed Rulemaking. On October 3, 2007, the Minerals Management Service (MMS) issued a Notice of Proposed Rulemaking for Oil and Gas and Sulphur Operations in the Outer Continental Shelf (OCS) Pipelines and Pipeline Rights-of-Way. If adopted, the proposed rules would substantially revise MMS OCS pipeline and rights-of-way regulations. The proposed rules would have the effect of: (1) increasing the financial obligations of entities, like us, which have pipelines and pipeline rights-of-way in the OCS; (2) increasing the regulatory requirements imposed on the operation and maintenance of existing pipelines in the OCS; and (3) increasing the requirements and preconditions for obtaining new rights-of-way in the OCS.

Rate of Return Proxy Groups. In April 2008, the FERC adopted a new policy that will allow master limited partnerships to be included in rate of return proxy groups for determining rates for services provided by interstate natural gas and oil pipelines. The FERC uses a discounted cash flow model that incorporates the use of proxy groups to develop a range of reasonable returns earned on equity interests in companies with corresponding risks. The FERC then assigns a rate of return on equity within that range to reflect specific risks of that pipeline when compared to the proxy group companies. The FERC s policy statement concludes among other items that (i) there should be no cap on the level of distributions included in the current discounted cash flow methodology and (ii) there should be a downward adjustment to the long-term growth rate used for the equity cost of capital of natural gas pipeline master limited partnerships. FERC is not exploring other methods of determining a pipeline s equity cost of capital at this time. We believe this ruling will not have a material impact on our financial position or results of operations.

EPNG Rate Case. In August 2007, EPNG received approval of the settlement of its rate case from the FERC. The settlement provided benefits for both EPNG and its customers for a three year period ending December 31, 2008. Under the terms of the settlement, EPNG is required to file a new rate case no later than June 30, 2008, for rates to be effective January 1, 2009. EPNG

Table of Contents

received approval from the FERC and began billing the settlement rates on October 1, 2007. In the first quarter of 2008, EPNG refunded the remaining $10 million in rate refunds owed to its customers pursuant to the settlement.

Other Matter

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. Our rights-of-way on lands crossing the Navajo Nation are the subject of a pending renewal application filed in 2005 with the Department of the Interior s Bureau of Indian Affairs. An interim agreement with the Navajo Nation expired at the end of December 2006. Negotiations on the terms of the long-term agreement are continuing. In addition, we continue to preserve other legal, regulatory and legislative 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. It is uncertain whether our negotiation, or other alternatives, will be successful, or if successful, what the ultimate cost will be of obtaining the rights-of-way or whether EPNG will be able to recover these costs in its rates.

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, 2008, we had accrued approximately $257 million, which has not been reduced by $25 million for amounts to be paid directly under government sponsored programs. Our accrual includes approximately $248 million for expected remediation costs and associated onsite, offsite and groundwater technical studies and approximately $9 million for related environmental legal costs. Of the $257 million accrual, $20 million was reserved for facilities we currently operate and $237 million was reserved for non-operating sites (facilities that are shut down or have been sold) and Superfund sites.

Our estimates of potential liability range from approximately $257 million to approximately $465 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 ($15 million). Second, where the most likely outcome cannot be estimated, a range of costs is established ($242 million to $450 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 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, 2008	
Sites	**Expected**	**High**
	(In millions)	
Operating	$ 20	$ 26
Non-operating	211	390
Superfund	26	49
Total	$ 257	$ 465

Below is a reconciliation of our accrued liability from January 1, 2008 to March 31, 2008 (in millions):

Balance as of January 1, 2008	$ 260
Additions/adjustments for remediation activities	7
Payments for remediation activities	(10)
Balance as of March 31, 2008	$ 257

For the remainder of 2008, we estimate that our total remediation expenditures will be approximately $54 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 $14 million in the aggregate for the years 2008 through 2012. These expenditures primarily relate to compliance with clean air regulations.

CERCLA Matters. As part of our environmental remediation projects, 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 40 active sites under the 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. 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 matters are included in the previously indicated estimates for Superfund sites.

It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as increasingly strict environmental laws, regulations and orders of regulatory agencies, as well as claims for damages to property and the environment or injuries to employees and other persons resulting from our current or past operations, could result in substantial costs and liabilities in the future. As this information becomes available, or other relevant developments occur, we will adjust our accrual amounts accordingly. While there are still uncertainties related to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe our reserves are adequate.

Guarantees and Indemnifications

We are involved in various joint ventures and other ownership arrangements that sometimes require financial and performance guarantees. In a financial guarantee, we are obligated to make payments if the guaranteed party fails to make payments under, or violates the terms of, the financial arrangement. In a performance guarantee, we provide assurance that the guaranteed party will execute on the terms of the contract. If they do not, we are required to perform on their behalf. We also periodically provide indemnification arrangements related to assets or businesses we have sold. These arrangements include, but are not limited to, indemnifications for income taxes, the resolution of existing disputes, and environmental matters.

Our potential exposure under guarantee and indemnification agreements can range from a specified amount to an unlimited dollar amount, depending on the nature of the claim and the particular transaction. For those arrangements with a specified dollar amount, we have a maximum stated value of approximately $851 million, which primarily relates to indemnification arrangements associated with the sale of ANR, our Macae power facility in Brazil, and other legacy assets. These amounts exclude guarantees for which we have issued related letters of credit discussed in Note 7. As of March 31, 2008, we have recorded obligations of $91 million related to our indemnification arrangements. This liability consists primarily of an indemnification that one of our subsidiaries provided related to its sale of an ammonia facility that is reflected in our financial statements at its fair value. We have provided a partial parental guarantee of our subsidiary s obligations under this indemnification. We are unable to estimate a maximum exposure for our guarantee and indemnification agreements that do not provide for limits on the amount of future payments due to the uncertainty of these exposures.

9. Retirement Benefits

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

	Pension Benefits		Other Postretirement Benefits	
	2008	**2007**	**2008**	**2007**
	(In millions)			
Service cost	$ 4	$ 5	$	$
Interest cost	30	30	7	6
Expected return on plan assets	(47)	(45)	(4)	(4)

Amortization of net actuarial loss (gain)	6	10	(1)	
Amortization of prior service cost[1]	(1)	(1)		
Net benefit cost (income)	$ (8)	$ (1)	$ 2	$ 2

(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.

Table of Contents

Other Matter. In various court rulings prior to March 2008, we were required to indemnify Case Corporation for certain benefits paid to a closed group of Case retirees as further discussed in Note 8. In conjunction with those rulings, we recorded a liability for estimated amounts due under the indemnification using actuarial methods similar to those used in estimating our postretirement benefit plan obligations. This liability, however, was not included in our postretirement benefit obligations or disclosures.

In March 2008, we received a summary judgment from the trial court on this matter that we effectively became the primary party that is obligated to pay for these benefit payments. As a result of the judgment, we adjusted our obligation using current actuarial assumptions, recording a $65 million reduction to current and non-current other liabilities and to operation and maintenance expense. We also reclassified this obligation from an indemnification liability to a postretirement benefit obligation, which increased our overall postretirement benefit obligations by $280 million as of March 31, 2008.

As of March 31, 2008, we expect the following payments under our postretirement benefit plans, net of participant contributions, which include the additional amounts related to the Case retirees described above:

Year Ending December 31,	**Other Postretirement Benefits(1) (In millions)**
2008	$ 63
2009	63
2010	62
2011	62
2012	61
2013-2017	287

(1) Includes a reduction of approximately $5 million per year for an expected subsidy related to the Medicare Prescription Drug Improvement and Modernization Act of 2003.

For the remainder of 2008, we expect to contribute an additional $43 million to our other postretirement benefit plans.

10. Stockholders Equity

The table below shows the amount of dividends paid and declared in 2008 (in millions, except per share amounts).

	Common Stock ($0.04/Share)	**Convertible Preferred Stock (4.99%/Year)**
Amount paid through March 31, 2008	$ 29	$ 9

Declared in February 2008:		
Date of declaration	February 7, 2008	February 7, 2008
Payable to shareholders on record	March 7, 2008	March 15, 2008
Date Paid	April 1, 2008	April 1, 2008
Amount Paid	$ 28	$ 9
Declared in March 2008:		
Date of declaration	March 31, 2008	March 31, 2008
Payable to shareholders on record	June 6, 2008	June 15, 2008
Date payable	July 1, 2008	July 1, 2008

Dividends on our common stock and preferred stock are treated as a reduction of additional paid-in-capital since we currently have an accumulated deficit. For the remainder of 2008, we expect dividends paid on our common and preferred stock will be taxable to our stockholders because we anticipate they will be paid out of current or accumulated earnings and profits for tax purposes.

The terms of our 750,000 outstanding shares of 4.99% convertible preferred stock prohibit the payment of dividends on our common stock unless we have paid or set aside for payment all accumulated and unpaid dividends on such preferred stock for all preceding dividend periods. In addition, although our credit facilities do not contain any direct restriction on the payment of dividends, dividends are included as a fixed charge in the calculation of our fixed charge coverage ratio under our credit facilities. If our fixed charge ratio were to exceed the permitted maximum level, our ability to pay additional dividends would be restricted.

Table of Contents

11. Business Segment Information

As of March 31, 2008, our business consists of two core segments, Pipelines and Exploration and Production. We also have Marketing and Power segments. Our segments are strategic business units that provide a variety of energy products and services. They are managed separately as each segment requires different technology and marketing strategies. Our corporate operations include our general and administrative functions, as well as other miscellaneous businesses and other various contracts and assets, all of which are immaterial. A further discussion of each segment follows.

Pipelines. Provides natural gas transmission, storage, and related services, primarily in the United States. As of March 31, 2008, we conducted our activities primarily through seven wholly or majority owned interstate pipeline systems and equity interests in three interstate transmission systems. We also own two underground natural gas storage entities, an LNG terminalling facility and have an interest in an LNG terminalling facility under construction.

Exploration and Production. Engaged in the exploration for and the acquisition, development and production of natural gas, oil and NGL, primarily in the United States, Brazil and Egypt.

Marketing. Markets and manages the price risks associated with our natural gas and oil production as well as our remaining legacy trading portfolio.

Power. Manages the risks associated with our remaining international power investments located primarily in Brazil, Asia and Central America. We continue to pursue the sale of these assets.

Our management uses earnings before interest expense and income taxes (EBIT) to assess the operating results and effectiveness of our business segments which consist of both consolidated businesses and investments in unconsolidated affiliates. We believe EBIT is useful to our investors because it allows them to more effectively evaluate the operating performance using the same performance measure analyzed internally by our management. We define EBIT as net income or loss adjusted for (i) items that do not impact our income or loss from continuing operations, such as discontinued operations and the impact of accounting changes, (ii) income taxes and (iii) interest and debt expense. We exclude interest and debt expense so that investors may evaluate our operating results without regard to our financing methods or capital structure. EBIT may not be comparable to measures used by other companies. Additionally, EBIT should be considered in conjunction with net income and other performance measures such as operating income or operating cash flow. Below is a reconciliation of our EBIT to our income from continuing operations for the quarters ended March 31:

	2008	2007
	(In millions)	
Segment EBIT	$ 561	$ 426
Corporate and other	39	(210)
Interest and debt expense	(233)	(283)
Income taxes	(148)	19
Income (loss) from continuing operations	$ 219	$ (48)

Table of Contents

The following table reflects our segment results for the quarters ended March 31:

	Segments					
	Pipelines	Exploration and Production	Marketing	Power	Corporate and Other[1]	Total
	(In millions)					
Quarters Ended March 31, 2008						
Revenue from external customers	$707	$ 83(2)	$ 469	$	$ 10	$1,269
Intersegment revenue	13	520(2)	(526)		(7)	
Operation and maintenance	195	108	2	5	(39)	271
Depreciation, depletion and amortization	99	212			2	313
Earnings from unconsolidated affiliates	21	10		5	1	37
EBIT	381	242	(60)	(2)	39	600
2007						
Revenue from external customers	$631	$ 220(2)	$ 159	$	$ 12	$1,022
Intersegment revenue	13	285(2)	(294)		(4)	
Operation and maintenance	161	110		4	26	301
Depreciation, depletion and amortization	94	170	1		6	271
Earnings (losses) from unconsolidated affiliates	26	(1)		11	1	37
EBIT	364	179	(135)	18	(210)	216

(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. During the

quarters ended March 31, 2008 and 2007, we recorded an intersegment revenue elimination of $6 million and $5 million in the Corporate and Other 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 segment, which is responsible for marketing our production to third parties.

Total assets by segment are presented below:

	March 31, 2008	December 31, 2007
	(In millions)	
Pipelines	$ 14,230	$ 13,939
Exploration and Production	7,417	8,029
Marketing	572	537
Power	519	531
Total segment assets	22,738	23,036
Corporate and Other	1,928	1,543
Total consolidated assets	$ 24,666	$ 24,579

12. Investments in, Earnings from and Transactions with Unconsolidated Affiliates

We hold investments in unconsolidated affiliates which are accounted for using the equity method of accounting. The earnings from unconsolidated affiliates reflected in our income statement include (i) our share of net earnings directly attributable to these unconsolidated affiliates, and (ii) any impairments and other adjustments recorded by us. The information below related to our unconsolidated affiliates includes (i) our net investment and earnings (losses) we recorded from these investments, (ii) summarized financial information of our proportionate share of these investments, and (iii) revenues and charges with our unconsolidated affiliates.

	Investment		Earnings (Losses) from Unconsolidated Affiliates Quarter Ended March 31,	
Net Investment and Earnings (Losses)	March 31, 2008	December 31, 2007	2008	2007
	(In millions)		(In millions)	
Four Star [1]	$ 692	$ 698	$ 10	$ (1)
Citrus	548	576	13	22
Gulf LNG[2]	295			
Bolivia to Brazil Pipeline	107	105	3	3
Gasoductos de Chihuahua	152	146	7	4
Manaus/Rio Negro[3]		56		4
Porto Velho[4]	(61)	(60)		2
Asian and Central American Investments[4]	26	26		
Argentina to Chile Pipeline	22	21	1	3
Other	65	46	3	
Total	$ 1,846	$ 1,614	$ 37	$ 37

(1) Amortization of our purchase cost in excess of the underlying net assets of Four Star was $14 million for the quarters ended March 31, 2008 and 2007.

(2) In February 2008, we acquired a 50 percent interest in Gulf LNG.

(3)

We transferred ownership of these plants to the power purchaser in January 2008. Accordingly, we eliminated our equity investments in these entities and retained current assets of $80 million and current liabilities of $24 million after the transfer. For a further discussion, see *Matters that Could Impact our Investments* below.

(4) As of March 31, 2008 and December 31, 2007, we had outstanding advances and receivables of $314 million and $350 million related to our foreign investments of which $307 million and $335 million related to our investment in Porto Velho.

	Quarter Ended March 31,	
Summarized Financial Information	2008	2007
	(In millions)	

Operating results data:		
Operating revenues	$ 186	$ 189
Operating expenses	93	111
Income from continuing operations	56	51
Net income[(1)]	56	51

(1) Includes net income of less than $1 million and $5 million for each of the quarters ended March 31, 2008 and 2007, related to our proportionate share of affiliates in which we hold a greater than 50 percent interest.

We received distributions and dividends from our unconsolidated affiliates of $60 million and $74 million for the quarters ended March 31, 2008 and 2007. Our revenues and charges with unconsolidated affiliates were not material during the quarter ended March 31, 2008. For the quarter ended March 31, 2007, we had $12 million in interest income primarily related to our note receivable with Porto Velho.

Matters that Could Impact Our Investments

Porto Velho. We have an equity investment in and a note receivable from the Porto Velho project in Brazil. The power generated by the Porto Velho project is committed to a state-owned utility under power purchase agreements, the largest of which extends through 2023. In July 2007, we received an offer from our partner to purchase our investment in the project. We continue to have discussions with our partner about this offer, although any sale is contingent, in part, upon the satisfactory resolution of certain claims with the state-owned utility, which are further described below. The power markets in Brazil continue to evolve and mature, and during 2007, the Brazilian national power grid operator communicated to Porto Velho s management that its power plant (and the region that the plant serves) will be interconnected to an integrated power grid in Brazil as soon as late 2008. When the interconnection is completed, the state-owned utility will have access to sources of power at rates that may be less than the price under Porto Velho s existing power purchase agreements. Furthermore, there are plans to construct new hydroelectric plants in northern Brazil that could reportedly be completed as early as 2012 which, once connected to the grid, could further reduce regional power prices and the amount of power Porto Velho will be able to sell under its power purchase agreements.

In February 2008, we received a payment from the project of approximately $29 million, and we and our partner extended to July 2008 the date on which we will be required to convert into equity approximately $80 million of the amounts due to us under the note receivable from Porto Velho. In addition, we may be required to convert up to an additional $80 million of the note in July 2008, depending on the level of equity that our partner contributes to the project, which would increase our percentage ownership in Porto Velho. Our total investment in the Porto Velho project was approximately $246 million as of March 31, 2008, comprised primarily of the note receivable from the project.

In December 2006, the Brazilian tax authorities assessed a $30 million fine against the Porto Velho power project for allegedly not filing the proper tax forms related to the delivery of fuel to the power facility under its power purchase agreements. We believe the claim by the tax authorities is without merit and a ruling by the first level courts in Brazil determined that the fine could not be applied as the statute of limitations had expired. The tax authorities have appealed this decision. In addition, the state-owned utility has made claims against the Porto Velho project for the period of 2003 through 2007 totaling approximately $60 million related to alleged excess fuel consumption. We believe that we have valid defenses to these fuel claims. The state-owned utility has made additional net claims of $30 million for retroactive currency indexation adjustments, which are partially offset by retroactive revenue surcharges for periods when the plant uses oil for fuel. We are currently evaluating this claim and are in negotiations with the utility to resolve these issues and the fuel consumption claims. Further adverse developments in the Brazilian power markets or at the project could impact our ability to recover our remaining investment in the future.

Manaus /Rio Negro. On January 15, 2008, we transferred our ownership in the Manaus and Rio Negro facilities to the plants power purchaser as required by their power purchase agreements. As of March 31, 2008, we have approximately $69 million of accounts receivable owed to us under the projects terminated power purchase agreements, which are guaranteed by the purchaser s parent. The purchaser has withheld payment of these receivables in light of their claims of approximately $64 million related to plant maintenance the purchaser claims should have been performed at the plants prior to the transfer, inventory levels and other items. We have been in ongoing discussions with the purchaser about their claims, and early in the second quarter of 2008 we began discussions with the parent of the purchaser. Should these discussions fail and the purchaser not agree to payment of our receivables, we will initiate legal action against the purchaser to collect our receivables and defend against their claims, and ultimately we will seek legal action to enforce the parental guarantee related to our receivables. We have reviewed our obligations under the power purchase agreement in relation to the claims and have accrued an obligation for the uncontested claims. We believe the remaining contested claims are without merit. The ultimate resolution of each of these matters is unknown at this time. Adverse developments related to either our ability to collect amounts due to us or related to the dispute could require us to record additional losses in the future.

Asian and Central American power investments. As of March 31, 2008, our total investment (including advances to the projects) and guarantees related to these projects was approximately $59 million. We are in the process of selling these assets. Any changes in political and economic conditions could negatively impact the amount of net proceeds we expect to receive upon their sale, which may result in additional impairments.

Table of Contents

Investment in Bolivia. We own an 8 percent interest in the Bolivia to Brazil pipeline. As of March 31, 2008, our total investment and guarantees related to this pipeline project was approximately $119 million, of which the Bolivian portion was $3 million. In 2006, the Bolivian government announced a decree significantly increasing its interest in and control over Bolivia s oil and gas assets. We continue to monitor and evaluate, together with our partners, the potential commercial impact that these political events in Bolivia could have on our investment. As new information becomes available or future material developments arise, we may be required to record an impairment of our investment.

Investment in Argentina. We own an approximate 22 percent interest in the Argentina to Chile pipeline. As of March 31, 2008, our total investment in this pipeline project was approximately $22 million. The Argentinian government has issued decrees significantly increasing export taxes on natural gas transported on the Argentina-to-Chile pipeline. We continue to monitor and evaluate, together with our partners, the potential impact that these events in Argentina could have on our investment. In the first quarter of 2008, we executed a letter of intent to sell our 22 percent interest to one of our partners, subject to the execution of definitive agreements and completion of due diligence by the buyer.

Table of Contents

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 2007 Annual Report on Form 10-K, and the financial statements and notes presented in Item 1 of this Quarterly Report on Form 10-Q.

Overview

Financial and Operational Update. During the quarter ended March 31, 2008, our pipeline operations continued to make progress on their almost $4 billion backlog of committed expansion projects which provide a strong base of earnings and cash flow. Our exploration and production business experienced continued success based on favorable commodity pricing and average daily production for the quarter was consistent with our full year 2008 targets. Compared with the same period in 2007, average daily production has increased eight percent, not including our equity investment in Four Star.

Outlook. For 2008, we expect the current operating trends in our core pipeline and exploration and production businesses to continue with a focus on continued growth of these businesses. We anticipate that our pipeline operations will continue to provide strong operating results based on significant planned growth capital expenditures including an almost $4 billion committed project backlog, current levels of contracted capacity, and recent rate and regulatory actions. In the pipeline industry, a favorable macroeconomic environment supports continued industry growth and we believe our systems are situated in locations that will allow us to be a major participant in this growth. We will continue to pursue expansion projects, including proposed joint venture development projects that would use our incumbent pipeline infrastructure to connect supply areas to areas of high demand in the west, northeast and southeast. Finally, we are committed to growing our MLP through organic growth opportunities, potential acquisitions, or through future asset contributions. Our MLP provides us financial flexibility, a competitive cost of capital on expansion opportunities, and is a strategic growth vehicle for El Paso.

In our exploration and production business, we expect to continue with the momentum established in 2007. We believe the combination of assets in our domestic regions provides significant near-term cash flows while providing consistent opportunities for competitive investment returns. In addition, our international activities in Brazil and Egypt provide opportunity for additional future reserve additions and longer term cash flows. In 2008, while our international capital is expected to increase approximately 50 percent over 2007, we expect our domestic programs will constitute approximately 80 percent of our total planned capital and substantially all of our expected production.

As previously announced, we received net proceeds of approximately $600 million on the sale of certain non-core properties in our Onshore Central, Onshore Western, Texas Gulf Coast and Gulf of Mexico regions as part of our portfolio high-grading efforts. We expect to close on the sale of the remaining non-core properties during the second quarter of 2008 for additional net proceeds of approximately $50 million. The sale of these properties, together with the Peoples Energy Production Company (Peoples) acquisition in 2007, increases the onshore U.S. weighting of our inventory of future capital projects and is expected to reduce our per-unit lease operating costs as well as increase our future production growth rate.

For a more detailed discussion of our operations, refer to our Annual Report on Form 10-K. For a more detailed discussion of liquidity and capital resources related matters, see below.

Table of Contents

Segment Results

We have two core operating business segments, Pipelines and Exploration and Production. We also have a Marketing segment that markets our natural gas and oil production and manages our legacy trading activities and a Power segment that has interests in several international power plants. Our segments are managed separately, provide a variety of energy products and services, and require different technology and marketing strategies. Our corporate activities include our general and administrative functions, as well as other miscellaneous businesses, contracts and assets all of which are immaterial.

Our management uses earnings before interest expense and income taxes (EBIT) as a measure to assess the operating results and effectiveness of our business segments, which consist of both consolidated businesses and investments in unconsolidated affiliates. We believe EBIT is useful to investors because it allows them to evaluate more effectively our operating performance using the same performance measure analyzed internally by our management. We define EBIT as net income (loss) adjusted for (i) items that do not impact our income or loss from continuing operations, such as discontinued operations, (ii) income taxes and (iii) interest and debt expense. We exclude interest and debt expense from this measure so that investors may evaluate our operating results without regard to our financing methods or capital structure. EBIT may not be comparable to measurements used by other companies. Additionally, EBIT should be considered in conjunction with net income and other performance measures such as operating income and operating cash flows.

Below is a reconciliation of our EBIT (by segment) to our consolidated net income for the quarters ended March 31:

	2008	2007
	(In millions)	
Segment		
Pipelines	$ 381	$ 364
Exploration and Production	242	179
Marketing	(60)	(135)
Power	(2)	18
Segment EBIT	561	426
Corporate and other	39	(210)
Consolidated EBIT	600	216
Interest and debt expense	(233)	(283)
Income taxes	(148)	19
Income (loss) from continuing operations	219	(48)
Discontinued operations, net of income taxes		677
Net income	$ 219	$ 629

Table of Contents

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 ending March 31, 2008 and 2007, or that could potentially impact EBIT in future periods.

	2008	2007
	(In millions, except volume amounts)	
Operating revenues	$ 720	$ 644
Operating expenses	(363)	(320)
Operating income	357	324
Other income	33	40
EBIT before minority interest	390	364
Minority interest	(9)	
EBIT	$ 381	$ 364
Throughput volumes (BBtu/d)[1]	19,321	18,040

(1) Throughput volumes include volumes associated with our proportionate share of unconsolidated affiliates.

	Quarter Ended March 31, 2008 Variance			
	Revenue Impact	Expense Impact	Other Impact	EBIT Impact
	Favorable/(Unfavorable) (In millions)			
Expansions	$ 24	$ (5)	$ (1)	$ 18
Reservation and usage revenues	11			11
Gas not used in operations and revaluations	7	7		14
Calpine bankruptcy settlement	29			29
Operating and general and administrative expenses		(11)		(11)
Gain/loss on long-lived assets		(23)		(23)
Equity earnings from Citrus			(9)	(9)
Minority interest			(9)	(9)
Other[1]	5	(11)	3	(3)
Total impact on EBIT	$ 76	$ (43)	$ (16)	$ 17

(1) Consists of individually insignificant items on several of our pipeline

systems.

Expansions. In 2008, we benefited from increased reservation revenues and throughput volumes due to projects placed in-service including the WIC Kanda lateral project in January 2008, and various projects placed in-service throughout 2007 including Phase I of the Cypress project, the Louisiana Deepwater Link project, the Triple-T extension project and the Northeast ConneXion-New England project. We received FERC approval for the High Plains Pipeline project in March 2008 and the Totem Gas Storage in April 2008.

During the quarter ended March 31, 2008, we continued to make progress on our almost $4 billion of committed backlog projects. Through March 31, 2008, we have spent approximately $0.4 billion on expansion projects and currently anticipate spending $0.5 billion for the remainder of 2008.

Other Large Development Projects. Our Ruby Pipeline project, which is not included in our backlog of committed growth projects, is currently in the process of obtaining necessary customer commitments. The project is estimated to cost over $2 billion with an estimated in-service date in 2011.

Table of Contents

Reservation and Usage Revenues. During the quarter ended March 31, 2008, our EBIT was favorably impacted by an increase in overall reservation and usage revenues. During 2008, we benefited from additional capacity sold in the northern and southern regions of our TGP system, additional interruptible and firm commodity services provided in several of our pipeline systems, and increased demand for the off-system capacity on our CIG system. Partially offsetting these favorable impacts was lower reservation revenues on our Mojave system due to a decrease in tariff rates under its 2007 rate case settlement and the expiration of certain firm contracts.

Gas Not Used in Operations and Revaluations. In February 2008, the FERC approved certain tariff changes to modify CIG s fuel recovery mechanism resulting in a favorable fuel cost and revenue tracker adjustment. The FERC s approval of this fuel and related gas cost recovery mechanism is expected to reduce future earnings volatility resulting from these items. The FERC order, which became effective March 1, 2008, includes a true-up mechanism to recover all cost impacts, or flow through to shippers any revenue impacts, of all fuel imbalance revaluations and related gas balance items.

Effective April 1, 2008, WIC implemented a FERC-approved fuel and related gas cost recovery mechanism that is expected to reduce future earnings volatility resulting from these items.

Calpine Bankruptcy Settlement. During the first quarter of 2008, we received a partial distribution under Calpine s approved plan of reorganization and recorded revenue of $29 million.

Operating, General and Administrative Expenses. For the quarter ended March 31, 2008, our operating and general and administrative expenses were higher than in 2007 primarily due to (i) increased insurance costs for wind damage on our pipeline assets located primarily in the Gulf of Mexico region; (ii) higher repair and maintenance costs related to our pipeline integrity program and (iii) increased direct payroll related benefits for our employees.

Gain/Loss on Long-Lived Assets. For the quarter ended March 31, 2008, we recorded impairments of $16 million primarily related to our decision not to proceed with the Essex-Middlesex project due to its prolonged permitting process and changing market conditions. In 2007, we recorded a $7 million pretax gain on the sale of a pipeline lateral.

Equity Earnings from Citrus. During the first quarter of 2008, equity earnings on our Citrus investment decreased as compared to the same period in 2007 primarily due to a favorable settlement in 2007 of approximately $8 million for litigation brought against Spectra LNG Sales (formerly Duke Energy LNG Sales, Inc.) for the wrongful termination of a gas supply contract.

Minority Interest. During the quarter ended March 31, 2008, we recorded approximately $9 million of minority interest expense related to our MLP formed in November 2007.

Other Regulatory Matters. In addition to the matters discussed above, our pipeline systems periodically file for changes in their rates, which are subject to the approval of the FERC. Changes in rates and other tariff provisions resulting from these regulatory proceedings have the potential to positively or negatively impact our profitability. Currently, while certain of our pipelines are expected to continue operating under their existing rates, other pipelines have projected upcoming rate actions with anticipated effective dates in 2009 through 2011.

Table of Contents

Exploration and Production Segment

Overview and Strategy

Our Exploration and Production segment conducts our natural gas and oil exploration and production activities. The profitability and performance in this segment are driven by the ability to locate and develop economic natural gas and oil reserves and extract those reserves at the lowest possible production and administrative costs. Accordingly, we manage this business with the goal of creating value through disciplined capital allocation, cost control and portfolio management. Our strategy focuses on building and applying competencies in assets with repeatable programs and where we have significant project inventory, sharpening our execution skills to improve capital and expense efficiency and maximizing returns, and adding assets with inventory that match our competencies and divesting assets that do not.

Our domestic natural gas and oil reserve portfolio blends lower decline rate, typically longer lived assets in our Onshore regions, with steeper decline rate, shorter lived assets in our Texas Gulf Coast and Gulf of Mexico and south Louisiana regions. At the beginning of 2008, our Onshore region was split into two operating areas, Onshore Central and Onshore Western. Onshore Central includes Arklatex, Black Warrior and Mid-Continent areas, and Onshore Western includes the Rockies and Raton Basin areas. We believe the combination of our assets in these domestic regions provides significant near-term cash flows while providing consistent opportunities for competitive investment returns. Our international activities in Brazil and Egypt provide opportunity for additional future reserve additions and longer term cash flows.

As previously announced, we entered into agreements to sell certain non-core properties in our Onshore Central, Onshore Western, Texas Gulf Coast and Gulf of Mexico regions for $755 million as part of our high-grading efforts. These properties had estimated proved reserves of approximately 309 Bcfe and estimated asset retirement obligations of $109 million at December 31, 2007. After normal post closing adjustments, we expect to receive total cash proceeds of approximately $650 million. During the first quarter of 2008, we closed on the sale of the majority of these properties for net cash proceeds of approximately $600 million. The remaining sales are expected to close during second quarter of 2008. The sale of these properties, together with our acquisition of Peoples Energy Company (Peoples) in 2007, increases the onshore U.S. weighting of our inventory of future capital projects and is expected to reduce our per-unit costs as well as increase our future production growth rate. The cash proceeds from the sale of these properties were used to repay debt incurred for the acquisition of Peoples.

Significant Operational Factors Affecting the Quarter Ended March 31, 2008

Production. Our average daily production volume for the three months ended March 31, 2008 was 811 MMcfe/d (which does not include 75 MMcfe/d from our share of production volume from our equity investment in Four Star). Average daily production for the three months ended March 31, 2008 associated with divested properties was 88 MMcfe/d. Below is an analysis of our production volumes by region for the quarters ended March 31:

	2008	2007
	(MMcfe/d)	
United States		
Onshore Central	241	213
Onshore Western	149	150
Texas Gulf Coast	236	189
Gulf of Mexico and south Louisiana	173	182
International		
Brazil	12	16
Total Consolidated	811	750
Four Star	75	70

Table of Contents

In the first quarter of 2008, we increased production volumes in our Onshore Central and Texas Gulf Coast operating regions. Our Onshore Central region production volumes increased due to our Peoples acquisition and a successful Arklatex drilling program. Our Texas Gulf Coast region production volumes increased due to the Peoples and Zapata County, Texas property acquisitions in 2007. Our Gulf of Mexico and south Louisiana region production volumes decreased due to natural production declines and asset sales partially offset by our successful drilling program at High Island and West Cameron areas. In Brazil, production volumes decreased primarily due to natural production declines.

2008 *Drilling Results*

Onshore Central. We realized a 100 percent success rate on 66 gross wells drilled.

Onshore Western. We realized a 100 percent success rate on two gross wells drilled.

Texas Gulf Coast. We experienced an 87 percent success rate on 23 gross wells drilled.

Gulf of Mexico and south Louisiana. We experienced a 50 percent success rate on 2 gross wells drilled.

Brazil. We currently own 100 percent of the BM-CAL-4 concession in the Camamu Basin. In 2007, we completed drilling two successful exploratory wells south of the Pinauna Field in this concession that extends the southern limits of the Pinauna project. We are currently evaluating development options, project risks and associated economics for the Pinauna project. These options include the sale of up to a 50 percent working interest to a third party. Regulatory and environmental approvals are required before we can enter the next major phase of development. In 2007, we also completed drilling and testing two exploratory wells with Petrobras in the ES-5 Block in the Espirito Basin. These wells confirmed the extension of an earlier discovery by Petrobras on a block to the south. We are currently in negotiations with Petrobras on a unitization agreement for the development of this discovery.

Egypt. We are in the process of acquiring seismic data on our operated South Mariut Block. The block is approximately 1.2 million acres and is located onshore in the western part of the Nile Delta. We expect to commence drilling operations in the fourth quarter of 2008. During the first quarter of 2008, we began drilling in the South Feiran block, which is our non-operated concession in the Gulf of Suez. Drilling is expected to be completed in the second quarter of 2008.

Cash Operating Costs. We monitor cash operating costs required to produce our natural gas and oil volumes. These costs are calculated on a per Mcfe basis and include total operating expenses less depreciation, depletion and amortization expense, other non-cash expense items and the cost of products and services on our income statement. During the quarter ended March 31, 2008, cash operating costs per unit decreased to $1.92/Mcfe as compared to $1.99/Mcfe during the same period in 2007. Our cash operating costs decreased primarily due to lower lease operating costs as a result of lower workover activity in the Gulf of Mexico and south Louisiana region partially offset by higher production taxes which increased due to higher natural gas and oil revenues.

Capital Expenditures. Our total natural gas and oil capital expenditures were $302 million for the three months ended March 31, 2008, of which $280 million were domestic capital expenditures.

Table of Contents

Outlook

For the full year 2008, we anticipate the following on a worldwide basis:

Average daily production volumes for the year of approximately 795 MMcfe/d to 850 MMcfe/d, which excludes approximately 65 MMcfe/d to 70 MMcfe/d from our equity investment in Four Star.

Capital expenditures, excluding acquisitions, of approximately $1.7 billion. While approximately 80% of the Company s planned 2008 capital program is allocated to its domestic program, we plan to spend approximately $350 million in international capital in 2008, primarily in our Brazil exploration and development program. As part of our domestic capital program, we will allocate a greater percentage of our capital to our Onshore Central, Onshore Western and Texas Gulf Coast regions, as compared to our 2007 capital program, in light of our first quarter 2008 asset divestitures.

Average cash operating costs which include production costs, general and administrative expenses and other expenses of approximately $1.75/Mcfe to $1.90/Mcfe for the year. Average cash operating costs could change primarily as a result of severance taxes which are sensitive to commodity prices; and

Depreciation, depletion and amortization rate of between $2.80/Mcfe and $3.20/Mcfe.

Price Risk Management Activities

As part of our strategy, we enter into derivative contracts on our natural gas and oil production to stabilize cash flows, to reduce the risk and financial impact of downward commodity price movements on commodity sales and to protect the economic assumptions associated with our capital investment programs. Because this strategy only partially reduces our exposure to downward movements in commodity prices, our reported results of operations, financial position and cash flows can be impacted significantly by movements in commodity prices from period to period. Adjustments to our hedging strategy and the decision to enter into new positions or to alter existing positions are made based on the goals of the overall company.

During the first quarter of 2008, we entered into floor and ceiling option contracts on approximately 47 TBtu of anticipated 2008 natural gas production and 48 TBtu of anticipated 2009 natural gas production. We also entered into 7 TBtu of fixed price swaps on anticipated 2008 natural gas production and 292 MBbls of fixed price swaps on our anticipated 2008 oil production.

The following tables reflect the contracted volumes and the minimum, maximum and average prices we will receive under our derivative contracts as of March 31, 2008. The tables below do not include contracts entered into by our Marketing segment. For the consolidated impact of the entirety of El Paso s production-related price risk management activities, see Liquidity and Capital Resources.

Derivatives designated as accounting hedges

	Fixed Price Swaps(1)		Floors(1)		Ceilings(1)	
	Volumes	Average Price	Volumes	Average Price	Volumes	Average Price
Natural Gas						
2008	19	$ 7.48	98	$8.00	98	$10.82
2009	5	$ 3.56	48	$8.35	48	$11.01
2010	5	$ 3.70				
2011-2012	6	$ 3.88				
Oil						
2008	1,880	$88.48				

(1)

Volumes presented are TBtu for natural gas and MBbl for oil. Prices presented are per MMBtu of natural gas and per Bbl of oil.

Table of Contents

Derivatives not designated as accounting hedges

	Fixed Price Swaps(1		Floors(1)		Ceilings(1)		Basis Swaps(1)(2)					
							Texas Gulf Coast		Onshore-Raton		Rockies	
	Volumes	Average Price	Volumes	Average Price	Volumes	Average Price	Volumes	Avg. Price	Volumes	Avg. Price	Volumes	Avg. Price
Natural Gas												
2008	6	$ 8.24	30	$ 8.00	30	$ 10.48	44	$ (0.33)	19	$ (1.13)	10	$ (1.37)
2009									15	$ (1.00)		

(1) Volumes presented are TBtu for natural gas and MBbl for oil. Prices presented are per MMBtu of natural gas and per Bbl of oil.

(2) Our basis swaps effectively limit our exposure to differences between the NYMEX gas price and the price at the location where we sell our gas. The average prices listed above are the amounts we will pay per MMBtu relative to the NYMEX price to lock-in these locational price differences.

Gains and losses associated with derivative contracts designated as hedges are deferred in accumulated other comprehensive income and are recognized in earnings upon the sale of the related production at market prices, resulting in a realized price that is approximately equal to the hedged price. Gains and losses associated with derivative contracts not designated as hedges are recognized in earnings each period.

In April and May 2008, we entered into option contracts on 24 TBtu of our anticipated 2009 natural gas production with a floor price of $9.00 per MMBtu and an average ceiling price of $18.22 per MMBtu. We also entered into fixed price swaps on 3,431 MBbls of our anticipated 2009 oil production at an average price of $109.93 per barrel. All of these contracts were designated as accounting hedges, except for 1,497 MBbls of the 2009 fixed price oil swaps.

Table of Contents

Operating Results and Variance Analysis

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

	2008	2007
	(In millions)	
Operating Revenues:		
Natural gas	$ 468	$ 408
Oil, condensate and NGL	159	88
Changes in fair value of derivative contracts not designated as accounting hedges	(35)	3
Other	11	6
Total operating revenues	603	505
Operating Expenses:		
Depreciation, depletion and amortization	(212)	(170)
Production costs	(91)	(86)
Cost of products and services	(24)	(24)
General and administrative expenses	(47)	(46)
Other	(3)	(2)
Total operating expenses	(377)	(328)
Operating income	226	177
Other income[1]	16	2
EBIT	$ 242	$ 179

(1) Includes equity earnings from our investment in Four Star.

	2008	2007	Percent Variance
Consolidated volumes, prices and costs per unit:			
Natural gas			
Volumes (MMcf)	61,810	56,713	9%
Average realized prices including hedges ($/Mcf)	$ 7.57	$ 7.19	5%
Average realized prices excluding hedges ($/Mcf)	$ 7.72	$ 6.46	20%
Average transportation costs ($/Mcf)	$ 0.28	$ 0.31	(10)%
Oil, condensate and NGL			
Volumes (MBbls)	1,992	1,788	11%
Average realized prices including hedges ($/Bbl)	$ 79.74	$ 49.32	62%
Average realized prices excluding hedges ($/Bbl)	$ 83.06	$ 50.07	66%
Average transportation costs ($/Bbl)	$ 0.71	$ 0.76	(7)%
Total equivalent volumes			
MMcfe	73,762	67,442	9%
MMcfe/d	811	750	8%

Production costs and other cash operating costs ($/Mcfe)			
Average lease operating costs	$ 0.82	$ 0.95	(14)%
Average production taxes[1]	0.42	0.32	31%
Total production costs	1.24	1.27	(2)%
Average general and administrative expenses	0.64	0.69	(7)%
Average taxes, other than production and income taxes	0.04	0.03	33%
Total cash operating costs	$ 1.92	$ 1.99	(4)%
Depreciation, depletion and amortization ($/Mcfe)	$ 2.87	$ 2.52	14%
Unconsolidated affiliate volumes (Four Star)			
Natural gas (MMcf)	5,121	4,941	4%
Oil, condensate and NGL (MBbls)	285	233	22%
Total equivalent volumes			
MMcfe	6,832	6,338	8%
MMcfe/d	75	70	7%

(1) Production taxes include ad valorem and severance taxes.

32

Quarter Ended March 31, 2008 Compared to Quarter Ended March 31, 2007

Our EBIT for the quarter ended March 31, 2008 increased $63 million as compared to the same period in 2007. The table below lists the significant variances in our operating results for the quarter ended March 31, 2008 as compared to the same period in 2007:

	Variances			
	Operating Revenue	Operating Expense	Other	EBIT
	Favorable/(Unfavorable) (In millions)			
Natural Gas Revenue				
Higher realized prices in 2008	$ 77	$	$	$ 77
Impact of hedges	(50)			(50)
Higher volumes in 2008	33			33
Oil, Condensate and NGL Revenues				
Higher realized prices in 2008	66			66
Impact of hedges	(5)			(5)
Higher volumes in 2008	10			10
Other Revenue				
Changes in fair value of derivatives not designated as accounting hedges	(38)			(38)
Other	5			5
Depreciation, Depletion and Amortization Expense				
Higher depletion rate in 2008		(25)		(25)
Higher production volumes in 2008		(15)		(15)
Production Costs				
Lower lease operating costs in 2008		4		4
Higher production taxes in 2008		(9)		(9)
Other				
Earnings from investment in Four Star			11	11
Other		(4)	3	(1)
Total Variances	$ 98	$ (49)	$ 14	$ 63

Natural gas, oil, condensate and NGL revenues. During the first quarter of 2008, revenues increased compared with the same period in 2007 due to higher production volumes and higher commodity prices, including the effects of our hedging program. Losses on hedging settlements were $15 million during the quarter ended March 31, 2008, as compared to gains of $40 million in the same period in 2007. During the first quarter of 2008, we also benefited from an increase in production volumes in our Onshore Central and Texas Gulf Coast regions compared to the same period in 2007.

Other revenue. During the first quarter of 2008, we recognized mark-to-market losses of $35 million compared to gains of $3 million during the same period in 2007 related to the changes in fair value of derivatives not designated as hedges. In the first quarter of 2008, we paid $4 million on contracts that settled during the period, compared to payments of $7 million on contracts that settled during the first quarter of 2007.

Depreciation, depletion and amortization expense. During the first quarter of 2008, our depletion rate increased as compared to the same periods in 2007 as a result of the Peoples and Zapata County, Texas acquisitions in 2007 and higher finding and development costs.

Production costs. Our production taxes increased during the first quarter of 2008 as compared to the same period in 2007 primarily due to higher natural gas and oil revenues. The increase in production taxes was partially offset by a reduction in lease operating costs primarily as a result of lower workover activity in the Gulf of Mexico and south Louisiana region.

Other. Our equity earnings from Four Star increased by $11 million as compared to the quarter ended March 31, 2007 primarily due to higher natural gas prices and higher production volumes. The production volume increase primarily relates to the increase in our equity ownership from 43 percent to 49 percent.

Table of Contents

Marketing Segment

Overview. Our Marketing segment s primary focus is marketing our Exploration and Production segment s natural gas and oil production and managing the Company s overall price risks, primarily through the use of natural gas and oil derivative contracts. In addition, we continue to manage and liquidate remaining legacy contracts which impact our operating results and the fair value of our portfolio. Prior to 2008, we entered into various agreements to reduce our exposure to these legacy contracts. Additionally, in the first quarter of 2008, we economically hedged the capacity risk associated with our Pennsylvania-New Jersey-Maryland (PJM) power portfolio. To the extent it is economical to do so, we may enter into additional agreements to reduce our exposure or liquidate our remaining legacy contracts before their expiration, which could affect our operating results in future periods. For a further discussion of our contracts in this segment, see our 2007 Annual Report on Form 10-K.

Our remaining exposure relates to changes in natural gas and oil prices, locational differences in commodity prices in the PJM power market, and changes in interest rates used to determine the fair value of our derivative contracts. As of March 31, 2008, we estimate that a 10 percent change in natural gas and oil prices would change the fair value of our derivatives by approximately $33 million while a 1 percent change in interest rates would change the fair market value of our derivatives by approximately $24 million.

Operating Results. During the quarter ended March 31, 2008, we generated an EBIT loss of $60 million primarily driven by changes in the fair value of our PJM power contracts and production-related natural gas and oil derivative contracts due primarily to increases in commodity prices and a decline in the interest rates used to determine the fair value of these contracts. Below is further information about our overall operating results during each of the quarters ended March 31:

	2008	2007
	(In millions)	
Revenue by Significant Contract Type:		
Production-Related Natural Gas and Oil Derivative Contracts:		
Changes in fair value of options and swaps	$ (21)	$ (87)
Contracts Related to Legacy Trading Operations:		
Natural gas transportation-related contracts:		
Demand charges	(9)	(27)
Settlements, net of termination payments	14	20
Changes in fair value of other natural gas derivative contracts		(24)
Changes in fair value of power contracts	(41)	(17)
Total revenues	(57)	(135)
Operating expenses	(3)	(1)
Operating loss	(60)	(136)
Other income, net		1
EBIT	$ (60)	$ (135)

Production-related Natural Gas and Oil Derivative Contracts

Our production-related natural gas and oil derivative contracts are designed to provide protection to El Paso against changes in natural gas and oil prices. These are in addition to those derivative contracts entered into by our Exploration and Production segment which are further described in the discussion of that segment above. For the consolidated impact of all of El Paso s production-related price risk management activities, refer to our Liquidity and Capital Resources discussion. The fair value of our derivative contracts is impacted by changes in commodity prices from period-to-period and is marked-to-market in our results.

Table of Contents

Listed below are the volumes and average prices associated with our production-related derivative contracts as of March 31, 2008:

	Floors[1]		Ceilings[1]	
	Volumes	Average Price	Volumes	Average Price
Natural Gas 2009[2]	17	$ 6.00	17	$ 8.75
Oil 2008	688	$ 55.00	688	$ 56.73

(1) Volumes presented are TBtu for natural gas and MBbl for oil. Prices presented are per MMBtu of natural gas and per Bbl of oil.

(2) In April 2008, we sold the $6.00 per MMBtu floor contracts for approximately $2 million.

We experience volatility in our financial results based on changes in the fair value of our option contracts which generally move in the opposite direction from changes in forward commodity prices. During the quarters ended March 31, 2008 and 2007, increases in commodity prices reduced the fair value of our option contracts resulting in losses. During the quarter ended March 31, 2008, we paid approximately $10 million on contracts settled during that period, while during the quarter ended March 31, 2007 we received approximately $17 million.

Contracts Related to Legacy Trading Operations

Natural gas transportation-related contracts. As of March 31, 2008, our transportation contracts provide us with approximately 0.6 Bcf/d of pipeline capacity. In 2008, we anticipate demand charges related to this capacity of approximately $41 million which we expect to steadily decline to an average of $24 million annually from 2009 through 2012. The profitability of these contracts is dependent upon the recovery of demand charges as well as our ability to use or remarket the contracted pipeline capacity, which is impacted by a number of factors including differences in natural gas prices at contractual receipt and delivery locations, the working capital needed to use this capacity, and the capacity required to meet our long-term obligations. In November 2007, we transferred our Alliance transportation contract to a third party which significantly reduced our demand charges. Our transportation contracts are accounted for on an accrual basis and impact our revenues as delivery or service under the contracts occurs.

Other natural gas derivative contracts. In addition to our natural gas transportation contracts, we have other contracts with third parties that require us to purchase or deliver natural gas primarily at market prices. While we have substantially offset all of the fixed price exposure in these contracts, they are still subject to changes in fair value due to changes in the interest rates used to value these contracts. During the quarter ended March 31, 2007, we assigned a weather call derivative which required us to supply gas in the northeast region if temperatures fell to specific levels resulting in a loss of $13 million.

Power contracts. Our power portfolio consists of contracts that require us to supply both energy and capacity in the PJM region, as well as swap locational differences in prices between specific locations in the PJM eastern region with the PJM west hub. Our 2008 losses were primarily a result of adjustments to the fair value of our PJM contracts due to locational differences in daily energy prices and changes in interest rates. Additionally, we executed a capacity purchase agreement with a counterparty for 195 MW of capacity per day at a fixed price of $195 per MW-day from June 2011 through April 2016. We entered into this capacity purchase agreement such that, when combined with capacity prices established in auctions held by the PJM Independent System Operator for periods prior to June 2011, we have economically hedged our exposure to supplying capacity in the PJM region for the remainder of the contract term. Prior to 2008, we had economically hedged the fixed commodity price exposure of supplying power under these contracts. Our remaining exposure to these contracts relates primarily to locational differences in daily energy prices and changes in interest rates used to determine the fair value of these contracts.

Table of Contents

Power Segment

Our Power segment consists of assets in Brazil, Asia and Central America. We continue to pursue the sale of these power investments. During the first quarter of 2008, our power purchase agreements for the Manaus and Rio Negro power plants expired and we transferred the ownership of these plants to the plants power purchaser. As of March 31, 2008, our net remaining investment, guarantees and letters of credit related to power projects in this segment totaled approximately $503 million which consisted of approximately $473 million in equity investments and notes and accounts receivable and approximately $30 million in financial guarantees and letters of credit, as follows (in millions):

Area	
Brazil	
Porto Velho	$ 246
Manaus & Rio Negro	57
Pipeline projects	141
Asia and Central America	59
Total investment, guarantees and letters of credit	$ 503

Operating Results. For the quarter ended March 31, 2008, our Power segment generated an EBIT loss of $2 million. In the first quarter of 2007, we had EBIT of $18 million generated primarily from interest on a note receivable with our Porto Velho project in Brazil. For a discussion of developments and other matters that could impact our Brazilian investments, see Item 1, Financial Statements and Supplementary Data, Note 12.

During the first quarters of 2007 and 2008, we did not recognize earnings from our Asian and Central American investments and in 2008 we did not recognize earnings from our Porto Velho project based on our inability to realize those earnings. We continue to pursue the sale of our remaining investments in this segment. Until the sale of these international investments is completed, any changes in regional political and economic conditions could negatively impact the anticipated proceeds we may receive, which could result in impairments of our investments.

Corporate and Other Expenses, Net

Our corporate activities include our general and administrative functions as well as a number of miscellaneous businesses, which do not qualify as operating segments and are not material to our current period results. The following is a summary of significant items impacting EBIT in our corporate activities for the quarters ended March 31:

	2008	**2007**
	(In millions)	
Loss on extinguishment of debt	$	$ (201)
Change in litigation, insurance and other reserves	11	(25)
Foreign currency fluctuations on Euro-denominated debt	(6)	(2)
Gain on disposition of a portion of our telecommunications business	18	
Other	16	18
Total EBIT	$ 39	$ (210)

Extinguishment of Debt. During the first quarter of 2007, we incurred losses of $201 million in conjunction with repurchasing $3.5 billion of debt. For further information on our debt, see Item 1, Financial Statements, Note 7.

Litigation, Insurance, and Other Reserves. We have a number of pending litigation matters and reserves related to our historical business operations. Adverse rulings or unfavorable outcomes or settlements against us related to these matters have impacted and may further impact our future results.

In March 2008, we received a summary judgment from a trial court on our Case Corporation indemnification dispute. As a result of the judgment, we adjusted our existing indemnification accrual using current actuarial assumptions, and reclassified amounts accrued as a postretirement benefit obligation. This resulted in a $65 million reduction in operation and maintenance expense. See Item I, Financial Statements, Notes 8 and 9 for a further discussion of the Case matter.

Table of Contents

During the first quarter of 2008, we recorded additional mark-to-market losses of approximately $43 million on an indemnification associated with the sale of a legacy ammonia facility. These losses were based on significant increases in ammonia prices during the first quarter of 2008. Changes in ammonia prices may continue to impact this contract, which could result in additional future losses.

Interest and Debt Expense

Our interest and debt expense was $233 million and $283 million during the quarters ended March 31, 2008 and 2007. This decrease was primarily due to lower average debt balances in 2008 when compared to 2007.

Income Taxes

	Quarter Ended March 31, 2008	Quarter Ended March 31, 2007
	(In millions, except for rates)	
Income taxes	$ 148	$ (19)
Effective tax rate	40%	28%

For a discussion of our effective tax rates and other matters impacting our income taxes, see Item 1, Financial Statements, Note 3.

Discontinued Operations

Income from our discontinued operations was $677 million for the quarter ended March 31, 2007. In February 2007, we sold ANR and related operations and recognized a gain in the first quarter of 2007 of $651 million, net of taxes of $356 million.

Commitments and Contingencies

For a further discussion of our commitments and contingencies, see Item I, Financial Statements, Note 8 which is incorporated herein by reference.

Table of Contents

Liquidity and Capital Resources

Overview. Our balance sheet enhancing activities over the past several years have given us financial flexibility and a manageable current debt maturity profile. We are now positioned to capitalize on our extensive backlog of committed pipeline projects as well as production-related growth projects while meeting our ongoing obligations. In regards to our credit metrics, our pipeline debt is currently rated investment grade and we continue to make progress on our corporate credit metrics. Future improvement in our credit metrics will be driven by the placement of pipeline projects in service, the ability to finance growth projects at competitive and attractive rates, and the ability to utilize our master limited partnership as a low-cost financing option.

Sources and Uses of Cash. Our primary sources of cash are cash flow from operations and amounts available to us under revolving credit facilities. On occasion and as conditions warrant, we also generate funds through various financings and proceeds from asset sales. Our primary uses of cash are funding the capital expenditure programs of our pipeline and exploration and production operations, meeting operating needs, and repaying debt when due or repurchasing certain debt obligations when conditions warrant.

2008 Cash Flow Activities. During the first quarter of 2008, we generated operating cash flow of approximately $0.6 billion, primarily as a result of cash provided by our pipeline and exploration and production operations. In addition, we generated $0.6 billion in proceeds from the sale of certain oil and gas properties. We utilized these amounts to fund maintenance and growth projects in our pipeline and exploration and production operations, which included the acquisition of a 50 percent interest in the Gulf LNG Clean Energy project, and to pay down amounts borrowed under our revolving credit facilities. For the quarter ended March 31, 2008, our cash flows from continuing operations are summarized as follows:

		2008
		(In billions)
Cash Flow from Operations		
Continuing operating activities		
Income from continuing operations	$	0.2
Other income adjustments		0.5
Change in other assets and liabilities		(0.1)
Total cash flow from operations	$	0.6
Other Cash Inflows		
Continuing investing activities		
Net proceeds from the sale of assets and investments	$	0.6
Continuing financing activities		
Net proceeds from the issuance of long-term debt[(1)]		1.2
Total other cash inflows	$	1.8
Cash Outflows		
Continuing investing activities		
Capital expenditures	$	0.5
Cash paid for acquisitions, net of cash required		0.3
		0.8
Continuing financing activities		
Payments to retire long-term debt and other financing obligations[(1)]		1.4

Total cash outflows	$	2.2
Net change in cash	$	0.2

(1) Relates primarily to the net activity under our revolving credit facilities.

Liquidity/Cash Flow Outlook. For the remainder of 2008, we expect to continue to generate positive operating cash flows from our core pipeline and production businesses. We also anticipate generating approximately $0.3 billion upon the completion of the remaining exploration and production asset divestitures and the sale of our remaining international power assets. We currently expect to use these cash sources, and additional financings, where necessary, to satisfy working capital requirements, fund our expected capital expenditures, repay debt maturities and complete planned debt repurchases. We have approximately $0.4 billion of debt that matures through March 31, 2009 and intend on repurchasing approximately $0.2 billion of SNG debt and approximately $0.1 billion of CIG debt in 2008 as previously announced.

Our capital expenditures (including acquisitions) for the quarter ended March 31, 2008, and the amount we expect to spend for the remainder of 2008 to grow and maintain our businesses are as follows (in billions):

	Quarter Ended March 31, 2008	2008 Remaining	Total
		(In billions)	
Pipelines			
Maintenance	$ 0.1	$ 0.4	$ 0.5
Growth	0.4(1)	0.5	0.9
Exploration and Production	0.3	1.4	1.7
Corporate and other(2)		0.1	0.1
	$ 0.8	$ 2.4	$ 3.2

(1) Includes approximately $0.3 billion related to the acquisition of Gulf LNG.

(2) Relates primarily to building renovations at our corporate facilities.

Factors That Could Impact Our Future Liquidity. Based on our current cash on hand, available liquidity through our revolving credit facilities, capital structure, and/or access to financial markets, we believe we can adequately provide for working capital requirements, forecasted capital expenditures, and upcoming debt maturities. However, our liquidity needs could increase or decrease based on cash margining requirements related to our price risk management activities, among other factors. For a complete discussion of risk factors that could impact our liquidity, see our 2007 Annual Report on Form 10-K.

Price Risk Management Activities and Cash Margining Requirements. Our Exploration and Production and Marketing segments have derivative contracts that provide price protection on a portion of our anticipated natural gas and oil production. The following table shows the contracted volumes and the minimum, maximum and average cash prices that we will receive under our derivative contracts when combined with the sale of the underlying production as of March 31, 2008. These cash prices may differ from the income impacts of our derivative contracts, depending on whether the contracts are designated as hedges for accounting purposes or not. The individual segment discussions provide additional information on the income impacts of our derivative contracts.

	Fixed Price						**Basis Swaps[1][2]**					
	Swaps[1]		**Floors[1]**		**Ceilings[1]**		**Texas Gulf Coast**		**Onshore-Raton**		**Rockies**	
	Volumes	**Average Price**	**Volumes**	**Average Price**	**Volumes**	**Average Price**	**Volumes**	**Avg. Price**	**Volumes**	**Avg. Price**	**Volumes**	**Avg. Price**
Natural Gas												
2008	25	$ 7.65	128	$ 8.00	128	$10.74	44	$(0.33)	19	$(1.13)	10	$(1.37)
2009	5	$ 3.56	65	$ 7.74	65	$10.42			15	$(1.00)		
2010	5	$ 3.70										
2011-2012	6	$ 3.88										
Oil												
2008	1,880	$88.48	688	$55.00	688	$56.73						

(1) Volumes presented are TBtu for natural gas and MBbl for oil. Prices presented are per MMBtu of natural gas and per Bbl of oil.

(2) Our basis swaps effectively limit our exposure to differences between the NYMEX gas price and the price at the location where we sell our gas. The average prices listed above are the amounts we will pay per MMBtu relative to the NYMEX price to lock-in these locational price differences.

Table of Contents

In April and May 2008, we entered into option contracts on 24 TBtu of our anticipated 2009 natural gas production with a floor price of $9.00 per MMBtu and an average ceiling price of $18.22 per MMBtu. We also entered into fixed price swaps on 3,431 MBbls of our anticipated 2009 oil production at an average price of $109.93 per barrel. All of these contracts were designated as accounting hedges, except for 1,497 MBbls of the 2009 fixed price oil swaps. In addition, we sold 17 TBtu of our $6.00 per MMBtu 2009 natural gas floor contracts.

We currently post letters of credit for the required margin on certain of our derivative contracts. For the remainder of 2008, based on current prices, we expect approximately $0.2 billion of the total of $1.0 billion in collateral outstanding at March 31, 2008 to be returned to us, a substantial portion of which will be in the form of letters of credit. Depending on changes in commodity prices, we could be required to post additional margin or may recover margin earlier than anticipated. Based on our derivative positions at March 31, 2008, a $0.10/MMBtu increase in the price curve of natural gas over the next several years would result in an increase in our margin requirements of approximately $7 million in the aggregate over the life of the contracts of which $3 million is associated with contracts expiring in 2008-2009 and $4 million is associated with contracts expiring in 2010 and beyond.

Commodity-Based Derivative Contracts

We use derivative financial instruments in our Exploration and Production and Marketing segments to manage the price risk of commodities. In the tables below, derivatives designated as accounting hedges primarily consist of options and swaps used to hedge natural gas production. Other commodity-based derivative contracts are not traded on active exchanges and relate to derivative contracts not designated as accounting hedges, such as options, swaps and other natural gas and power purchase and supply contracts. The following table details the fair value of our commodity-based derivative contracts by year of maturity and valuation methodology as of March 31, 2008:

	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 accounting hedges						
Assets	$	$ 3	$	$	$	$ 3
Liabilities	(148)	(45)	(24)			(217)
Total derivatives designated as accounting hedges[1]	(148)	(42)	(24)			(214)
Other commodity-based derivatives						
Assets	45	79	56	14	3	197
Liabilities	(288)	(393)	(265)	(160)		(1,106)
Total other commodity-based derivatives[1][2]	(243)	(314)	(209)	(146)	3	(909)
Total commodity-based derivatives	$ (391)	$ (356)	$ (233)	$ (146)	$ 3	$ (1,123)

(1)

Includes positions whose fair value is primarily based on commodity prices quoted on exchanges such as the NYMEX.

(2) Includes positions whose fair values are derived from third party pricing data and valuation techniques that consider specific contractual terms, statistical and simulation analysis, present value concepts, and other internal assumptions.

The following is a reconciliation of our commodity-based derivatives for the quarter ended March 31, 2008:

	Derivatives Designated as Accounting Hedges	Other Commodity-Based Derivatives	Total Commodity-Based Derivatives
		(In millions)	
Fair value of contracts outstanding at January 1, 2008	$ (23)	$ (869)	$ (892)
Fair value of contract settlements during the period	2	57	59
Changes in fair value of contracts	(193)	(97)	(290)
Net changes in contracts outstanding during the period	(191)	(40)	(231)
Fair value of contracts outstanding at March 31, 2008	$ (214)	$ (909)	$ (1,123)

Table of Contents

Item 3. Quantitative and Qualitative Disclosures About Market Risk

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

Commodity Price Risk

Production-Related Derivatives. We attempt to mitigate commodity price risk and stabilize cash flows associated with our forecasted sales of natural gas and oil production through the use of derivative natural gas and oil swaps, basis swaps and option contracts. These derivative contracts are entered into by both our Exploration & Production and Marketing segments. The table below presents the hypothetical sensitivity to changes in fair values arising from immediate selected potential changes in the quoted market prices of the derivative commodity instruments used to mitigate these market risks. We have designated certain of these derivatives as accounting hedges. Contracts that are designated as accounting hedges will impact our earnings when the related hedged production sales occur, and, as a result, any gain or loss on these hedging derivatives would be offset by a gain or loss on the sale of the underlying hedged commodity, which is not included in the table. Contracts that are not designated as accounting hedges impact our earnings as the fair value of these derivatives changes. Our production-related derivatives do not mitigate all of the commodity price risks of our forecasted sales of natural gas and oil production and, as a result, we are subject to commodity price risks on our remaining forecasted natural gas and oil production.

		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	(Decrease)	Fair Value	Increase
Impact of changes in commodity prices on production-related derivative assets (liabilities)					
March 31, 2008	$ (299)	$ (471)	$ (172)	$ (142)	$ 157
December 31, 2007	$ (64)	$ (181)	$ (117)	$ 58	$ 122

Other Commodity-Based Derivatives. In our Marketing segment, we have other derivative contracts that are not used to mitigate the commodity price risk associated with our natural gas and oil production. Many of these contracts, which include forwards, swaps, options and futures, are long-term historical contracts that we either intend to assign to third parties or manage until their expiration. We measure risks from these contracts on a daily basis using a Value-at-Risk simulation. This simulation allows us to determine the maximum expected one-day unfavorable impact on the fair values of those contracts of adverse market movements over a defined period of time within a specified confidence level and allows us to monitor our risk in comparison to established thresholds. To measure Value-at-Risk, we use what is known as the historical simulation technique. This technique simulates potential outcomes in the value of our portfolio based on market-based price changes. Our exposure to changes in fundamental prices over the long-term can vary from the exposure using the one-day assumption in our Value-at-Risk simulations. We supplement our Value-at-Risk simulations with additional fundamental and market-based price analyses, including scenario analysis and stress testing to determine our portfolio s sensitivity to underlying risks. These analyses and our Value-at-Risk simulations do not include commodity exposures related to our production-related derivatives (described above), our Marketing segment s natural gas transportation related contracts that are accounted for under the accrual basis of accounting, or our Exploration and Production segment s sales of natural gas and oil production.

Our maximum expected one-day unfavorable impact on the fair values of our other commodity-based derivatives as measured by Value-at-Risk based on a confidence level of 95 percent and a one-day holding period was $2 million and $1 million as of March 31, 2008 and December 31, 2007. We may experience changes in our Value-at-Risk in the future if commodity prices are volatile.

Table of Contents

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of March 31, 2008, 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 U.S. Securities and Exchange Commission reports we file or submit under the Exchange Act is accurate, complete and timely. Our management, including our CEO and our CFO, does not expect that our disclosure controls and procedures or our internal controls will prevent and/or detect all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our company have been detected. Based on the results of our evaluation, our CEO and our CFO concluded that our disclosure controls and procedures are effective at a reasonable assurance level at March 31, 2008.

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 of 2008.

PART II OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Financial Statements, Note 8, which is incorporated herein by reference. Additional information about our legal proceedings can be found in Part I, Item 3 of our 2007 Annual Report on Form 10-K filed with the SEC.

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 and operating performance;
- operating income;
- management s plans; and
- goals and objectives for future operations.

Forward-looking statements are subject to risks and uncertainties. While we believe the assumptions or bases underlying the forward-looking statements are reasonable and are made in good faith, we caution that assumed facts or bases almost always vary from actual results, and these variances can be material, depending upon the circumstances. We cannot assure you that the statements of expectation or belief contained in our 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 our forward-looking statements are described in our 2007 Annual Report on Form 10-K under Part I, Item 1A, Risk Factors. 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.

Table of Contents

Item 5. Other Information

None.

Item 6. Exhibits

The Exhibit Index is incorporated herein by reference and lists the exhibits required to be filed by this report by Item 601(b)(10)(iii) of Regulation S-K.

Table of Contents

SIGNATURES

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

	EL PASO CORPORATION
Date: May 9, 2008	/s/ D. Mark Leland
	D. Mark Leland Executive Vice President and Chief Financial Officer (Principal Financial Officer)
Date: May 9, 2008	/s/ John R. Sult
	John R. Sult Senior Vice President and Controller (Principal Accounting Officer)

Table of Contents

EL PASO CORPORATION
EXHIBIT INDEX

Each exhibit identified below is filed with this Report.

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.

46