EL PASO CORP/DE
Form 10-Q
August 10, 2009

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 June 30, 2009

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 has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
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 August 5, 2009: 701,196,377

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

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

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

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

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PART I FINANCIAL INFORMATION

Item 1. Financial Statements

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

	Quarters Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Operating revenues	$ 973	$ 1,153	$ 2,457	$ 2,422
Operating expenses				
Cost of products and services	52	71	113	127
Operation and maintenance	264	275	564	546
Ceiling test charges	12	7	2,080	7
Depreciation, depletion and amortization	197	298	453	611
Taxes, other than income taxes	57	81	125	160
	582	732	3,335	1,451
Operating income (loss)	391	421	(878)	971
Earnings from unconsolidated affiliates	12	52	31	89
Other income, net	16	33	38	55
Interest and debt expense	(253)	(221)	(508)	(454)
Income (loss) before income taxes	166	285	(1,317)	661
Income tax expense (benefit)	66	87	(460)	235
Net income (loss)	100	198	(857)	426
Net income attributable to noncontrolling interests	(11)	(7)	(23)	(16)
Net income (loss) attributable to El Paso Corporation	89	191	(880)	410
Preferred stock dividends	10		19	19
Net income (loss) attributable to El Paso Corporation s common stockholders	$ 79	$ 191	$ (899)	$ 391
Basic earnings per common share				
Net income (loss) attributable to El Paso Corporation s common stockholders	$ 0.11	$ 0.27	$ (1.29)	$ 0.56
Diluted earnings per common share				
Net income (loss) attributable to El Paso Corporation s common stockholders	$ 0.11	$ 0.25	$ (1.29)	$ 0.54

Dividends declared per El Paso Corporation s common share	$ 0.05	$	$ 0.10	$ 0.08

See accompanying notes.

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EL PASO CORPORATION

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

	June 30, 2009	December 31, 2008
ASSETS		
Current assets		
Cash and cash equivalents	$ 970	$ 1,024
Accounts and notes receivable		
Customers, net of allowance of $11 in 2009 and $9 in 2008	342	466
Affiliates	131	133
Other	127	217
Materials and supplies	190	187
Assets from price risk management activities	459	876
Deferred income taxes	114	
Other	138	148
Total current assets	2,471	3,051
Property, plant and equipment, at cost		
Pipelines	18,749	18,042
Natural gas and oil properties, at full cost	20,341	20,009
Other	363	342
	39,453	38,393
Less accumulated depreciation, depletion and amortization	22,844	20,535
Total property, plant and equipment, net	16,609	17,858
Other assets		
Investments in unconsolidated affiliates	1,724	1,703
Assets from price risk management activities	176	201
Other	663	855
	2,563	2,759
Total assets	$ 21,643	$ 23,668

See accompanying notes.

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

	June 30, 2009	December 31, 2008
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 304	$ 372
Affiliates	7	6
Other	495	674
Short-term financing obligations, including current maturities	169	1,090
Liabilities from price risk management activities	185	250
Accrued interest	204	192
Other	698	659
Total current liabilities	2,062	3,243
Long-term financing obligations, less current maturities	13,477	12,818
Other		
Liabilities from price risk management activities	577	767
Deferred income taxes	182	565
Other	1,626	1,679
	2,385	3,011
Commitments and contingencies (Note 9)		
Equity		
El Paso Corporation 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 715,683,940 shares in 2009 and 712,628,781 shares in 2008	2,147	2,138
Additional paid-in capital	4,537	4,612
Accumulated deficit	(3,533)	(2,653)
Accumulated other comprehensive loss	(650)	(532)
Treasury stock (at cost); 14,493,649 shares in 2009 and 14,061,474 shares in 2008	(281)	(280)
Total El Paso Corporation stockholders equity	2,970	4,035
Noncontrolling interests	749	561

Total equity	3,719	4,596
Total liabilities and equity	$ 21,643	$ 23,668

See accompanying notes.

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

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Cash flows from operating activities		
Net income (loss)	$ (857)	$ 426
Adjustments to reconcile net income (loss) to net cash from operating activities		
Depreciation, depletion and amortization	453	611
Ceiling test charges	2,080	7
Deferred income tax expense (benefit)	(470)	236
Earnings from unconsolidated affiliates, adjusted for cash distributions	4	(8)
Other non-cash income items	26	13
Asset and liability changes	(63)	33
Net cash provided by operating activities	1,173	1,318
Cash flows from investing activities		
Capital expenditures	(1,363)	(1,175)
Cash paid for acquisitions, net of cash acquired		(336)
Net proceeds from the sale of assets and investments	300	659
Other	(3)	43
Net cash used in investing activities	(1,066)	(809)
Cash flows from financing activities		
Net proceeds from issuance of long-term debt	983	2,670
Payments to retire long-term debt and other financing obligations	(1,214)	(3,071)
Dividends paid	(89)	(75)
Net proceeds from issuance of noncontrolling interests	184	
Distributions to noncontrolling interest holders	(19)	(12)
Other	(6)	(32)
Net cash used in financing activities	(161)	(520)
Change in cash and cash equivalents	(54)	(11)
Cash and cash equivalents		
Beginning of period	1,024	285
End of period	$ 970	$ 274

See accompanying notes.

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

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
El Paso Corporation stockholders equity:		
Preferred stock:		
Balance at beginning and end of period	$ 750	$ 750
Common stock:		
Balance at beginning of period	2,138	2,128
Other, net	9	8
Balance at end of period	2,147	2,136
Additional paid-in capital:		
Balance at beginning of period	4,612	4,699
Dividends	(89)	(75)
Other, including stock-based compensation	14	55
Balance at end of period	4,537	4,679
Accumulated deficit:		
Balance at beginning of period	(2,653)	(1,834)
Net income (loss) attributable to El Paso Corporation	(880)	410
Cumulative effect of adopting SFAS No. 158, net of income tax of $2		4
Balance at end of period	(3,533)	(1,420)
Accumulated other comprehensive loss:		
Balance at beginning of period	(532)	(272)
Other comprehensive loss	(118)	(348)
Cumulative effect of adopting SFAS No. 158, net of income tax of $2		3
Balance at end of period	(650)	(617)
Treasury stock, at cost:		
Balance at beginning of period	(280)	(191)
Stock-based and other compensation	(1)	(13)
Balance at end of period	(281)	(204)
Total El Paso Corporation stockholders equity at end of period	2,970	5,324

Noncontrolling interests:

Balance at beginning of period	561	565
Distributions paid to noncontrolling interests	(19)	(12)
Issuance of noncontrolling interests	184	
Net income attributable to noncontrolling interests	23	16
Other		(24)
Balance at end of period	749	545
Total equity at end of period	$ 3,719	$ 5,869

See accompanying notes.

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

	Quarters Ended June 30,		Six Months Ended June 30,	
	2009	**2008**	**2009**	**2008**
Net income (loss)	$ 100	$ 198	$ (857)	$ 426
Pension and postretirement obligations:				
Unrealized actuarial losses arising during period (net of income taxes of $1 in 2008)				(2)
Reclassification of actuarial gains and losses during period (net of income taxes of $4 and $8 in 2009 and $3 and $5 in 2008)	7	5	14	10
Cash flow hedging activities:				
Unrealized mark-to-market gains (losses) arising during period (net of income taxes of $7 and $8 in 2009 and $152 and $222 in 2008)	8	(272)	10	(395)
Reclassification adjustments for changes in initial value to the settlement date (net of income taxes of $34 and $80 in 2009 and $21 and $22 in 2008)	(60)	37	(142)	39
Other comprehensive loss	(45)	(230)	(118)	(348)
Comprehensive income (loss)	55	(32)	(975)	78
Comprehensive income attributable to noncontrolling interests	(11)	(7)	(23)	(16)
Comprehensive income (loss) attributable to El Paso Corporation	$ 44	$ (39)	$ (998)	$ 62

See accompanying notes.

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EL PASO CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Basis of Presentation and Significant Accounting Policies

Basis of Presentation

We prepared this Quarterly Report on Form 10-Q under the rules and regulations of the United States Securities and Exchange Commission (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 2008 Annual Report on Form 10-K, which contains a summary of our significant accounting policies and other disclosures. The financial statements as of June 30, 2009, and for the quarters and six months ended June 30, 2009 and 2008, are unaudited. We derived the condensed consolidated balance sheet as of December 31, 2008, from the audited balance sheet filed in our 2008 Annual Report on Form 10-K. As discussed below, certain amounts related to noncontrolling interests have been retrospectively adjusted within these consolidated financial statements to reflect the adoption of Statement of Financial Accounting Standards (SFAS) No. 160, *Noncontrolling Interests in Consolidated Financial Statements*. Our financial statements for prior periods also include certain reclassifications that were made to conform to the current period presentation. There were no reclassifications that impacted our reported net income (loss) or stockholders equity other than those required by SFAS No. 160. In our opinion, we have made adjustments, all of which are of a normal, recurring nature to fairly present our interim period results. We have evaluated subsequent events through the time of filing on August 7, 2009, the date of issuance of our financial statements. Due to the seasonal nature of our businesses, information for interim periods may not be indicative of our operating results for the entire year.

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 2008 Annual Report on Form 10-K.

Fair Value Measurements. On January 1, 2009, we adopted the provisions of SFAS No. 157, *Fair Value Measurements,* for our non-financial assets and liabilities that are measured at fair value on a non-recurring basis, as further described in Note 6. The adoption did not have a material impact on our financial statements.

On January 1, 2009, we adopted the provisions of the Emerging Issues Task Force (EITF) Issue No. 08-5, *Issuer s Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement.* EITF Issue No. 08-5 provides guidance to companies about how they should consider their own credit in determining the fair value of their liabilities that have third party credit enhancements related to them. Substantially all of our derivative liabilities in our Marketing segment are supported by letters of credit. This standard requires that non-cash credit enhancements, such as letters of credit, should not be considered in determining the fair value of these liabilities, including derivative liabilities. Accordingly, we recorded a $34 million gain (net of $18 million of taxes), or $0.05 per share, in the first quarter of 2009 as a result of adopting EITF Issue No. 08-5.

Business Combinations. On January 1, 2009, we adopted SFAS No. 141(R), *Business Combinations*, which provides revised guidance on the accounting for acquisitions of businesses. This standard changes the current guidance to require that all acquired assets, liabilities, noncontrolling interests and certain contingencies be measured at fair value, and certain other acquisition-related costs be expensed rather than capitalized. SFAS No. 141(R) applies to acquisitions that are effective after December 31, 2008.

Noncontrolling Interests. Effective January 1, 2009, we adopted the provisions of SFAS No. 160, which provides guidance on accounting and reporting for noncontrolling interests in the financial statements. This standard requires us to present our noncontrolling interests, which primarily relate to El Paso Pipeline Partners, L.P., our consolidated subsidiary, as a separate component of equity rather than as a mezzanine item between liabilities and equity in our balance sheets, and also requires us to present our noncontrolling interests as a separate caption in our income statements. Our financial statements for all periods presented have been adjusted to retrospectively apply the provisions of this statement. This standard also requires that all transactions with noncontrolling interest holders after adoption, including the issuance and repurchase of noncontrolling interests, be accounted for as equity transactions unless a change in control of the subsidiary occurs.

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New Accounting Pronouncements Issued But Not Yet Adopted

As of June 30, 2009, the following accounting standards have not yet been adopted by us:

Oil and Gas Reserves Reporting. In December 2008, the SEC issued a final rule adopting revisions to its oil and gas reporting requirements. The revisions will impact the determination and disclosures of oil and gas reserves information. Among other items, the new rules will revise the definition of proved reserves and will require full cost companies to use a twelve month average commodity price in determining future net revenues, rather than a period-end price as is currently required. These changes, along with other proposed changes, will impact the manner in which we perform our full cost ceiling test calculation and determine any related ceiling test charge. The provisions of this final rule are effective on December 31, 2009, and cannot be applied earlier than that date. We are currently assessing the impact that this final rule may have on our determination and disclosures of oil and gas reserves information.

Transfers of Financial Assets. In June 2009, the Financial Accounting Standards Board (FASB) issued SFAS No. 166, *Accounting for Transfers of Financial Assets*, which amends SFAS No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities a replacement of FASB Statement No. 125*. Among other items, this standard eliminates the concept of a qualifying special-purpose entity (QSPE) for purposes of evaluating whether an entity should be consolidated as a variable interest entity. SFAS No. 166 is effective for existing QSPEs as of January 1, 2010 and for transactions entered into on or after January 1, 2010. We are currently assessing the impact that this standard may have on our financial statements, including any impacts it may have on accounting for our accounts receivable sales program and the related senior beneficial interests (see Note 13).

Variable Interest Entities. In June 2009, the FASB issued SFAS No. 167, *Amendments to FASB Interpretation No. 46(R)*, which revises how companies determine who the primary beneficiaries of their variable interest entities are. This standard requires companies to use a qualitative approach based on their responsibilities and controlling power over the variable interest entities operations rather than a quantitative approach as previously required. SFAS No. 167 will be effective beginning January 1, 2010, and will require us to reevaluate the primary beneficiaries of our variable interest entities. We are currently assessing the impact that this standard may have on our financial statements.

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 of which we have advanced approximately $42 million as of June 30, 2009. Our partner in this project has a commitment to loan up to $64 million. We account for our investment in Gulf LNG using the equity method.

Exploration and Production properties. In June 2008, we acquired interests in onshore domestic natural gas and oil properties for approximately $43 million.

Divestitures

During the first quarter of 2009, we completed the sale of our interest in the Porto Velho power generation facility in Brazil to our partner in the project for total consideration of $179 million, including $78 million in notes receivable (see Note 13). Subsequently, in the second quarter of 2009, we sold the notes, including accrued interest, to a third party financial institution for $57 million and recorded a loss of approximately $22 million. In addition, during 2009 we completed the sale of our investment in the Argentina-to-Chile pipeline to our partners in the project for approximately $32 million and completed the sale of non-core natural gas producing properties located in our Central and Western regions for approximately $95 million. During 2008, we sold natural gas and oil properties primarily in the Gulf Coast region for total proceeds of $637 million as well as two power investments located in Central America and Asia.

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3. Ceiling Test Charges

In the first quarter of 2009, we recorded a reduction to our property, plant and equipment due to non-cash ceiling test charges of $2.1 billion that resulted primarily from declines in natural gas prices. Capitalized costs exceeded the ceiling limit by approximately $2.0 billion for our domestic full cost pool, approximately $28 million for our Brazilian full cost pool and approximately $9 million for our Egyptian full cost pool. The calculation of these ceiling test charges was based on the March 31, 2009 spot natural gas price of $3.63 per MMBtu and oil price of $49.66 per barrel.

As of June 30, 2009, spot natural gas prices improved to $3.89 per MMBtu and oil prices to $69.89 per barrel. As a result of these higher commodity prices and lower costs, we did not have a ceiling test charge in our domestic or Brazilian full cost pools during the second quarter of 2009. However, we recorded a $12 million charge during the second quarter of 2009 in our Egyptian full cost pool. Additionally, during the second quarter of 2008, we recorded a $7 million charge in our Egyptian full cost pool.

In performing our ceiling test charge calculations, we are required to hold prices constant over the life of the reserves, even though actual prices of natural gas and oil are volatile and change from period to period. Subsequent to June 30, 2009, commodity prices have declined, and as such, we may be required to record additional ceiling test charges in the future.

4. Income Taxes

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

	Quarters Ended June 30,		Six Months Ended June 30,	
	2009	**2008**	**2009**	**2008**
	(In millions, except rates)			
Income tax (benefit) expense	$ 66	$ 87	$ (460)	$ 235
Effective tax rate	40%	31%	35%	36%

Effective Tax Rate. 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. Our effective tax rate may be affected by items such as dividend exclusions on earnings from unconsolidated affiliates where we anticipate receiving dividends, the effect of state income taxes (net of federal income tax effects), and the effect of foreign income which can be taxed at different rates.

During the second quarter of 2009, our effective tax rate was primarily impacted by the sale and writedown of certain foreign investments for which there was no U.S. tax impact. For the six months ended June 30, 2009, our effective tax rate was relatively consistent with the statutory rate and the customary relationship between our pretax accounting income and income tax expense. During the second quarter of 2008, our effective tax rate was primarily impacted by the tax impact of the settlement of legacy litigation matters. For the six months ended June 30, 2008, this impact was largely offset by the tax impact of adjusting our postretirement benefit obligations, as discussed in Note 10.

Deferred Tax Asset. As of June 30, 2009, we have a net federal deferred tax asset of $138 million primarily as a result of recognizing a deferred tax benefit attributable to the domestic ceiling test charge during the first quarter of 2009. We believe it is more likely than not that we will realize the benefit of this net deferred tax asset (net of existing valuation allowances) based on recognition of sufficient taxable income during periods in which those temporary differences or net operating losses are deductible.

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5. Earnings Per Share

We calculated basic and diluted earnings per common share as follows:

Quarters Ended June 30,

	2009		2008	
	Basic	**Diluted**	**Basic**	**Diluted**
	(In millions, except per share amounts)			
Net income attributable to El Paso Corporation	$ 89	$ 89	$ 191	$ 191
Convertible preferred stock dividends	(10)	(10)	(1)	
Net income attributable to El Paso Corporation s common stockholders	$ 79	$ 79	$ 191	$ 191
Weighted average common shares outstanding	696	696	698	698
Effect of dilutive securities:				
Options and restricted stock		3		5
Convertible preferred stock				58
Weighted average common shares outstanding and dilutive securities	696	699	698	761
Basic and diluted earnings per common share:				
Net income attributable to El Paso Corporation s common stockholders	$ 0.11	$ 0.11	$ 0.27	$ 0.25

Six Months Ended June 30,

	2009		2008	
	Basic	**Diluted**	**Basic**	**Diluted**
	(In millions, except per share amounts)			
Net income (loss) attributable to El Paso Corporation	$ (880)	$ (880)	$ 410	$ 410
Convertible preferred stock dividends	(19)	(19)	(19)(1)	
Net income (loss) attributable to El Paso Corporation s common stockholders	$ (899)	$ (899)	$ 391	$ 410
Weighted average common shares outstanding	695	695	698	698
Effect of dilutive securities:				
Options and restricted stock				4
Convertible preferred stock				58
Weighted average common shares outstanding and dilutive securities	695	695	698	760

Basic and diluted earnings per common share:

Net income (loss) attributable to El Paso Corporation s common stockholders	$ (1.29)	$ (1.29)	$ 0.56	$ 0.54

(1) Dividends were declared in February and March 2008. No dividends were declared during the quarter ended June 30, 2008.

We exclude potentially dilutive securities (as well as their related income statement impacts) from the determination of diluted earnings per share when their impact on net income attributable to El Paso Corporation per common share is antidilutive. These potentially dilutive securities consist of our employee stock options, restricted stock, convertible preferred stock and trust preferred securities. For the six months ended June 30, 2009, we incurred losses attributable to El Paso Corporation 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 the quarters ended June 30, 2009 and 2008, and six months ended June 30, 2008, certain of our employee stock options, restricted stock and trust preferred securities were antidilutive. Additionally, for the quarter ended June 30, 2009, our convertible preferred stock was antidilutive. For a further discussion of our potentially dilutive securities, see our 2008 Annual Report on Form 10-K.

6. Fair Value Measurements

We apply the provisions of SFAS No. 157, *Fair Value Measurements*, to our assets and liabilities that are measured at fair value. We adopted the provisions of SFAS No. 157 on January 1, 2009 for our non-financial assets and liabilities that are measured at fair value on a non-recurring basis, which primarily relates to any impairment of long-lived assets or investments. During the six months ended June 30, 2009, we did not have any non-financial assets and liabilities that were recorded at fair value subsequent to their initial measurement.

We use various methods to determine the fair values of our financial instruments and other derivatives that are measured at fair value on a recurring basis, 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 for the instruments in actively traded markets. Included in this level are our marketable securities invested in non-qualified compensation plans whose fair value is determined using the quoted prices of these instruments.

Level 2 instruments fair values are primarily 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 foreign currency and interest rate swaps. Also 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 third party pricing sources and our creditworthiness or that of our counterparties (adjusted for collateral related to our asset positions).

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 obtain pricing data from third party pricing sources, adjust this data based on the liquidity of the underlying forward markets over the contractual terms and use the adjusted pricing data to develop an estimate of forward price curves that market participants would use. 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; (iii) the limited availability of forward pricing information in markets where there is a lack of viable participants, such as in the Pennsylvania-New Jersey-Maryland (PJM) forward power market and the forward market for ammonia; and (iv) our creditworthiness or that of our counterparties (adjusted for collateral related to our asset positions). Since a significant portion of the fair value of our power-related derivatives 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.

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Listed below are the fair values of our financial instruments that are recorded at fair value classified in each level at June 30, 2009 (in millions):

	Level 1	Level 2	Level 3	Total
Assets				
Commodity-based derivatives				
Production-related natural gas and oil derivatives	$	$ 499	$	$ 499
Other natural gas derivatives		55	27	82
Power-related derivatives			46	46
Interest rate derivatives		8		8
Marketable securities invested in non-qualified compensation plans	19			19
Total assets	19	562	73	654
Liabilities				
Commodity-based derivatives				
Production-related natural gas and oil derivatives		(66)		(66)
Other natural gas derivatives		(127)	(148)	(275)
Power-related derivatives			(405)	(405)
Interest rate derivatives		(16)		(16)
Other			(29)	(29)
Total liabilities		(209)	(582)	(791)
Total	$ 19	$ 353	$ (509)	$ (137)

On certain derivative contracts recorded as assets we are exposed to the risk that our counterparties may not be able to perform or post the required collateral, if any, with us. We have assessed this counterparty risk in light of the collateral our counterparties have posted with us and the current instability in the credit markets. Based on this assessment, we have determined that our exposure is primarily related to our production-related derivatives and foreign currency swaps and is limited to five financial institutions, each of which has a current Standard & Poor s credit rating of A or better.

The following table presents the changes in our financial assets and liabilities included in Level 3 for the quarter and six months ended June 30, 2009 (in millions):

Quarter Ended June 30, 2009

	Balance at Beginning of Period	Change in fair value reflected in operating revenues[1]	Change in fair value reflected in operating expenses[2]	Settlements, net	Balance at End of Period
Assets	$ 79	$ (4)	$	$ (2)	$ 73
Liabilities	(659)	26	26	25	(582)
Total	$ (580)	$ 22	$ 26	$ 23	$ (509)

Six Months Ended June 30,2009					
Assets	$ 103	$ (25)	$	$ (5)	$ 73
Liabilities	(751)	88	25	56	(582)
Total	$ (648)	$ 63	$ 25	$ 51	$ (509)

(1) Includes approximately $20 million and $45 million of net gains that had not been realized through settlements for the quarter and six months ended June 30, 2009.

(2) Includes approximately $26 million and $25 million of net gains that had not been realized through settlements for the quarter and six months ended June 30, 2009.

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The following table reflects the carrying value and fair value of our financial instruments:

	June 30, 2009		December 31, 2008	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Long-term financing obligations, including current maturities	$13,646	$12,417	$13,908	$11,227
Marketable securities invested in non-qualified compensation plans	19	19	19	19
Commodity-based derivatives	(119)	(119)	(25)	(25)
Interest rate and foreign currency derivatives	(8)	(8)	85	85
Other	17	17	72	72

As of June 30, 2009 and December 31, 2008, the carrying amounts of cash and cash equivalents, short-term borrowings, and trade receivables and payables represented fair value because of the short-term nature of these instruments. The carrying amounts of our restricted cash and noncurrent receivables approximate their fair value based on their interest rates and our assessment of our ability to recover these amounts. We estimated the fair value of debt based on quoted market prices for the same or similar issues, including consideration of our credit risk related to those instruments.

7. Price Risk Management Activities

Our price risk management activities relate primarily to derivatives entered into to hedge or otherwise reduce (i) the commodity exposure on our natural gas and oil production; (ii) interest rate exposure on our long-term debt; and (iii) our historical foreign currency exposure on our Euro-denominated debt. We also hold other derivatives not intended to hedge these exposures, including those related to our legacy trading activities. When we enter into derivative contracts, we may designate the derivative as either a cash flow hedge or a fair value hedge, at which time we prepare the documentation required under SFAS No. 133. Hedges of cash flow exposure are designed to hedge forecasted sales transactions or limit the variability of cash flows to be received or paid related to a recognized asset or liability. Hedges of fair value exposure are entered into to protect the fair value of a recognized asset, liability or firm commitment. A detailed discussion and analysis of our various price risk management activities follows below and in the related tables.

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. Our production-related derivatives do not mitigate all of the commodity price risks of our 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. Prior to removing the accounting hedge designation on all of our production-related derivatives during the fourth quarter of 2008, certain of these derivatives were designated as cash flow hedges. As of June 30, 2009 and December 31, 2008, we have production-related derivatives on 393 TBtu and 187 TBtu of natural gas and 902 MBbl and 3,431 MBbl of oil.

Other Commodity-Based Derivatives. In our Marketing segment, we have long-term natural gas and power derivative contracts that are primarily related to our legacy trading activities, which include forwards, swaps and options that we either intend to manage until their expiration or seek opportunities to liquidate to the extent it is economical and prudent. None of these derivatives are designated as accounting hedges. As of June 30, 2009 and December 31, 2008, our other commodity based derivative contracts include (i) natural gas contracts that obligate us to sell natural gas to power plants and have various expiration dates ranging from 2012 to 2019, with expected obligations under individual contracts with third parties ranging from 12,550 MMBtu/d to 104,750 MMBtu/d and (ii) derivative power contracts that require us to swap locational differences in power prices between three power plants in the PJM eastern region with the PJM west hub on approximately 3,700 GWh from 2009 to 2012, 2,400 GWh for 2013 and 1,700 GWh from 2014 to April 2016. Additionally, these contracts require us to provide approximately 1,700 GWh of power per year and approximately 71 GW of installed capacity per year in the PJM power pool through April 2016. For both the natural gas and power contracts discussed above, we have entered into contracts in previous years to economically mitigate our exposure to commodity price changes on substantially all of these volumes, although we continue to have exposure to changes in locational price differences between the PJM regions.

Interest Rate Derivatives. We have long-term debt with variable interest rates that exposes us to changes in market-based interest rates. We use interest rate swaps to convert the variable rates on certain of these debt instruments to a fixed interest rate. As of June 30, 2009 and December 31, 2008, we have interest rate swaps designated as cash flow hedges that converted the interest rate on approximately $175 million of debt from a LIBOR-based variable rate to a fixed rate of 4.56%.

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In addition, we have long-term debt with fixed interest rates that exposes us to paying higher than market rates should interest rates decline. We use interest rate swaps to protect the value of certain of these debt instruments by converting the fixed amounts of interest due under the debt agreements to variable interest payments and have recorded changes in the fair value of these derivatives in interest expense. As of June 30, 2009 and December 31, 2008, we have interest rate swaps designated as fair value hedges that converted the interest rate on approximately $218 million of debt from a fixed rate to a variable rate of LIBOR plus 4.18%. In addition, as of June 30, 2009 and December 31, 2008, we had interest rate swaps not designated as hedges with a notional amount of $222 million for which changes in the fair value of these swaps are substantially eliminated by offsetting swaps.

Cross-Currency Derivatives. In May 2009, our Euro-denominated debt matured and we settled all of our related cross-currency swaps. These cross-currency swaps were designated as fair value hedges of this debt.

Balance Sheet Presentation. Our derivatives are reflected on our balance sheet at their fair value as assets and liabilities from price risk management activities. We net our derivative assets and liabilities for counterparties where we have a legal right of offset and classify our derivatives as either current or non-current assets or liabilities based on their anticipated settlement date. The following table presents the fair value of our derivatives on a gross basis by contract. The derivative asset and liability amounts presented below are summarized by contract type and have not been netted for counterparties where we have a legal right of offset or for cash collateral associated with these derivatives, which is not significant to our financial statements.

	Fair Value of Asset Derivatives		**Fair Value of Liability Derivatives**	
	June 30, 2009	**December 31, 2008**	**June 30, 2009**	**December 31, 2008**
	(In millions)			
Derivatives Designated as Hedges:				
Cash flow hedges				
Interest rate derivatives	$	$	$ (16)	$ (21)
Fair value hedges				
Interest rate derivatives	8	12		
Cross-currency derivatives		94		
Total derivatives designated as hedges	8	106	(16)	(21)
Derivatives not Designated as Hedges:				
Commodity-based derivatives				
Production-related	626	738	(193)	(56)
Other natural gas	659	853	(852)	(1,122)
Power-related	70	111	(429)	(549)
Total commodity-based derivatives	1,355	1,702	(1,474)	(1,727)
Interest rate derivatives	9	12	(9)	(12)
Total derivatives not designated as hedges	1,364	1,714	(1,483)	(1,739)
Impact of master netting arrangements[1]	(737)	(743)	737	743
Total assets (liabilities) from price risk management activities	635	1,077	(762)	(1,017)

Other derivatives[2]						(29)		(55)
Total derivatives	$	635	$	1,077	$	(791)	$	(1,072)

(1) Includes adjustments to net assets or liabilities to reflect master netting arrangements we have with our counterparties.

(2) Included in other current and noncurrent liabilities in our balance sheets.

Statements of Income, Comprehensive Income and Cash Flow Presentation. Derivatives that we have designated as accounting hedges impact our revenues or expenses based on the nature and timing of the transactions that they hedge. Changes in derivative fair values that are designated as cash flow hedges are deferred in accumulated other comprehensive income or loss to the extent that they are effective and then recognized in earnings when the hedged transactions occur. Ineffectiveness related to our cash flow hedges is recognized in earnings as it occurs. Changes in the fair value of derivatives that are designated as fair value hedges are recognized in earnings as offsets to the changes in fair values of the related hedged assets, liabilities or firm commitments.

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Derivatives that we have not designated as accounting hedges are marked-to-market each period and changes in their fair value are generally reflected as operating revenues, except as indicated in the table below. In our cash flow statement, cash inflows and outflows associated with the settlement of our derivative instruments are recognized in operating cash flows (other than those derivatives intended to hedge the principal amounts of our foreign currency denominated debt, which are recorded in financing activities). Listed below are the impacts to our income statement and statement of comprehensive income for the quarter and six months ended June 30, 2009:

Quarter Ended June 30, 2009

	Operating Revenues	Interest Expense	Other Income (in millions)	Other Comprehensive Income (Loss)
Commodity-based derivatives				
Production-related derivatives(1)	$ 55	$	$	$ (99)
Other natural gas and power derivatives not designated as hedges	18			
Total commodity-based derivatives	73			(99)
Interest rate and foreign currency derivatives(2)				
Designated as cash flow hedges(3)		1	(5)	5
Designated as fair value hedges(4)		1		
Cross-currency derivatives designated as fair value hedges(4)		1	3	
Total interest rate and foreign currency derivatives		3	(2)	5
Total price risk management activities(5)	$ 73	$ 3	$ (2)	$ (94)
Six Months Ended June 30, 2009				
Commodity-based derivatives				
Production-related derivatives(1)	$ 449	$	$	$ (227)
Other natural gas and power derivatives not designated as hedges	73			
Total commodity-based derivatives	522			(227)
Interest rate and foreign currency derivatives(2)				
Designated as cash flow hedges(3)		2	(5)	8
Designated as fair value hedges(4)		2		
Cross-currency derivatives designated as fair value hedges(4)		3	(21)	
Total interest rate and foreign currency derivatives.		7	(26)	8
Total price risk management activities (5)	$ 522	$ 7	$ (26)	$ (219)

(1) Included in operating revenues for the quarter and six months ended June 30, 2009 is $99 million and $227 million representing the amount of accumulated other comprehensive income that was reclassified into income related to commodity-based derivatives for which we removed the hedging designation during the fourth quarter of 2008. We anticipate that approximately $173 million of our accumulated other comprehensive income will be reclassified to operating revenues during the next twelve months.

(2) We have not reflected in this table approximately $3 million and $5 million of losses recognized for the quarter and six months ended June 30, 2009 related to interest rate derivatives not designated as hedges that were offset completely by the impact of certain swaps. Settlements related to these swaps were not material for the quarter and six months ended June 30, 2009.

(3) Included in these amounts is less than $1 million representing the amount of accumulated other comprehensive income that was reclassified into income related to these hedges. We anticipate that $2 million of our accumulated other comprehensive income will be reclassified to interest expense during the next twelve months. No

ineffectiveness was recognized on our interest rate cash flow hedges for the quarter and six months ended June 30, 2009.

(4) Amounts only reflect the financial statement impact of these derivative contracts. The table does not reflect the offsetting impact of changes to the carrying value of the underlying debt hedged by these derivative instruments as a result of changes in fair value attributable to the risk being hedged, which is also recorded in other income and interest expense and substantially offsets the financial statement impact of these derivatives. We also recorded a decrease to interest expense of approximately $1 million and $2 million during the quarter and six months ended June 30, 2009 as a result of converting the interest rate on the underlying debt from a fixed rate to a floating rate. No ineffectiveness was recognized on our fair value hedges for the quarter and six months ended June 30, 2009.

(5) We also had approximately $26 million and $25 million of gains for the quarter and six months ended June 30, 2009 recognized in operating expenses related to other derivative instruments not associated with our price risk management activities.

8. Debt, Other Financing Obligations and Other Credit Facilities

	June 30, 2009	December 31, 2008
	(In millions)	
Short-term financing obligations, including current maturities	$ 169	$ 1,090
Long-term financing obligations	13,477	12,818
Total	$ 13,646	$ 13,908

Changes in Long-Term Financing Obligations. During the six months ended June 30, 2009, we had the following changes in our long-term financing obligations (in millions):

Company	Interest Rate	Book Value Increase (Decrease)	Cash Received (Paid)
Issuances			
El Paso Notes due 2016[1]	8.25%	$ 478	$ 473
Tennessee Gas Pipeline (TGP) notes due 2016[1]	8.00%	237	234
Southern LNG notes due 2014 and 2016	9.60%	135	134
Elba Express Company LLC credit facility	variable	99	92
El Paso Pipeline Partners, L.P. (EPB) revolving credit facilities	variable	50	50
Increases through June 30, 2009		$ 999	$ 983
Repayments, repurchases, and other			
El Paso Corporation			
Notes due 2009	6.375% to 7.125%	$ (1,054)	$ (1,054)[2]
Revolving credit facilities	variable	(97)	(97)
EPB revolving credit facilities	variable	(115)	(115)
El Paso Exploration and Production Company (EPEP) revolving credit facility	variable	(20)	(20)
Other	variable	25	(11)
Decreases through June 30, 2009		$ (1,261)	$ (1,297)

(1) Principal amount of the notes is $500 million for El Paso Corporation and $250 million for TGP.

(2) Amount does not reflect $83 million received in conjunction with the settlement of fair value hedges related to our Euro

denominated notes.

Credit Facilities. As of June 30, 2009, we had total available capacity under various credit agreements (not including capacity available under the EPB $750 million revolving credit facility) of approximately $1.5 billion. In determining our available capacity, we have assessed our lender s ability to fund under our various credit facilities, as further discussed in our 2008 Annual Report on Form 10-K.

During the first six months of 2009, we increased the size of or entered into new letter of credit facilities totaling $225 million. As of June 30, 2009, we had total letter of credit capacity under these facilities of $250 million with a weighted average fixed facility fee of 6.90% and maturities ranging from December 2013 to September 2014. Additionally, in June 2009, $150 million of another letter of credit facility entered into in 2007 matured.

The availability of borrowings under our credit agreements and our ability to incur additional debt is subject to various financial and non-financial covenants and restrictions. These restrictions include potential limitations in the credit agreements of certain of our subsidiaries on their ability to declare and pay dividends and loan funds to us. As of June 30, 2009 and December 31, 2008, the restricted net assets of our consolidated subsidiaries were less than $1 million and approximately $1 billion. Additionally, the revolving credit facility of our exploration and production subsidiary is collateralized by certain of our natural gas and oil properties and has a borrowing base subject to revaluation on a semi-annual basis. Our existing borrowing base was approved by the banks in May 2009 and will be redetermined in November 2009. There have been no significant changes to our restrictive covenants from those disclosed in our 2008 Annual Report on Form 10-K and as of June 30, 2009, we were in compliance with all of our debt covenants.

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 June 30, 2009, we had outstanding letters of credit issued under all of our facilities of approximately $1.6 billion. Included in this amount is approximately $0.8 billion of letters of credit securing our recorded obligations related to price risk management activities.

Other. In the second quarter of 2009, our wholly owned subsidiary, Elba Express Company, secured a $165 million non-recourse financing facility, which is available only to the related pipeline project. As of June 30, 2009, $99 million has been borrowed under this facility.

9. Commitments and Contingencies

Legal Proceedings

ERISA Class Action Suit. 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). A settlement has been finalized, received court approval and been paid.

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 trial court has dismissed the plaintiffs claims. The plaintiffs have filed a motion seeking to overturn the dismissal of the case. Our costs and legal exposure related to this lawsuit are not currently determinable.

Retiree Medical Benefits Matters. In 2002, a lawsuit entitled *Yolton et al. v. El Paso Tennessee Pipeline Co. and Case Corporation* was filed in a federal court in Detroit, Michigan. The lawsuit was filed on behalf of a group of retirees of Case Corporation (Case) that alleged they are entitled to retiree medical benefits under a medical benefits plan for which we serve as plan administrator pursuant to a merger agreement with Tenneco Inc. Although we had asserted that our obligations under the plan were subject to a cap pursuant to an agreement with the union for Case employees, in the first quarter of 2008, the trial court granted a summary judgment and ruled that the benefits were vested and not subject to the cap. As a result, we were obligated to pay the amounts above the cap and we adjusted our existing indemnification accrual using current actuarial assumptions and reclassified our liability as a postretirement benefit obligation. See Note 10 for a discussion of the impact of this matter. 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 above the cap 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); *Heartland, et al. v. Oneok Inc., et al.* (filed in the circuit court of Buchanan County, Missouri in March 2007); and *Newpage Wisconsin System, Inc., et al.* (filed in the circuit court of Wood County, Wisconsin in March 2009). The *Leggett* case was dismissed by the Tennessee state court, but in October 2008, the Tennessee Court of Appeals reversed the dismissal, remanding the matter to the trial court. The decision has been appealed to the Tennessee Supreme Court. The *Missouri Public Service* case was dismissed by the state court. The dismissal has been appealed. *Newpage* was recently filed. The remaining cases have all been transferred to the MDL proceeding. The *Breckenridge Case* has been dismissed as to El Paso and other defendants, and a motion for reconsideration of this decision was denied. This ruling can still be appealed. Discovery is proceeding in the MDL cases. We reached an agreement to settle the *Western States* and *Ever-Bloom* cases, subject to court approval, and have established accruals for those cases, which we believe are adequate. Our costs and legal exposure related to the remaining lawsuits and claims are not currently determinable.

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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 and 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. In March 2009, the Tenth Circuit Court of Appeals affirmed the dismissals and in May 2009, the plaintiff s motion for reconsideration was denied.

Similar allegations were filed in a 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 plaintiffs seek 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, produced, sold or distributed methyl tertiary-butyl ether (MTBE) as a gasoline additive. Various lawsuits were filed throughout the U.S. regarding the potential impact of MTBE on water supplies. The lawsuits have been brought by different parties, including state attorney generals, water districts and individual water companies. They have sought different remedies, including remedial activities, damages, attorneys fees and costs. These cases were initially consolidated for pre-trial purposes in multi-district litigation in the U.S. District Court for the Southern District of New York. Several cases were later remanded to state court. In 2008, we settled 59 of these lawsuits. The settlement payments were covered by insurance and we were reimbursed for the payments by our insurers. Additionally, in July 2009, we made payment on an additional settled case which is expected to be covered by insurance. Following dismissal of the settled cases we have 31 lawsuits that remain. Although there have been settlement discussions with other plaintiffs, such discussions have been unsuccessful to date. While the damages claimed in the 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. We have or will tender these remaining cases to our insurers. It is likely that our insurers will assert denial of coverage on the 11 most-recently filed cases. Our costs and legal exposure related to these remaining lawsuits are not currently determinable.

In addition to the above proceedings, we and our subsidiaries and affiliates are named defendants in numerous lawsuits and governmental proceedings and claims 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 or claim, 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 June 30, 2009, we had approximately $59 million accrued for our outstanding legal and governmental proceedings.

Rates and Regulatory Matters

EPNG Rate Case. In June 2008, El Paso Natural Gas Company (EPNG) filed a rate case with the Federal Energy Regulatory Commission (FERC) as required under the settlement of its previous rate case. The filing proposed an increase in EPNG s base tariff rates. In August 2008, the FERC issued an order accepting the proposed rates effective January 1, 2009, subject to refund and the outcome of a hearing and a technical conference. The FERC issued an order in December 2008 that generally accepted most of EPNG s proposals in the technical conference proceeding. The FERC has appointed an administrative law judge to preside over a hearing if EPNG is unable to reach a negotiated settlement with its customers on the remaining issues. The hearing is currently scheduled to begin in late

October 2009. The outcome of the hearing is not currently determinable.

SNG Rate Case. In March 2009, Southern Natural Gas Company (SNG) filed a rate case with the FERC as permitted under the settlement of its previous rate case. The filing proposed an increase in SNG s base tariff rates. In April 2009, the FERC issued an order accepting the proposed rates effective September 1, 2009, subject to refund and the outcome of a hearing and a technical conference on certain tariff proposals. The FERC has appointed an administrative law judge to preside over a hearing if SNG is unable to reach a negotiated settlement with its customers on the remaining issues. The hearing is currently scheduled to begin in February 2010. The outcome of the hearing is not currently determinable.

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 and rights-of-way in the OCS; and (3) increasing the requirements and preconditions for obtaining new rights-of-way in the OCS.

Other Matter

Navajo Nation. In March 2009, representatives of the Navajo Nation and EPNG executed a final agreement setting forth the full terms and conditions of the Navajo Nation s consent to EPNG s rights-of-way through the Navajo Nation. EPNG submitted the Navajo Nation s consent agreement in support of EPNG s pending application to the United States Department of the Interior for an extension of the Department s current right-of-way grant. We expect the submission will result in the Department s final processing of our application. EPNG has filed with the FERC for recovery of these amounts in its recent rate case.

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. At June 30, 2009, we had accrued approximately $190 million for environmental matters, which has not been reduced by $24 million for amounts to be paid directly under government sponsored programs or through settlement arrangements. Our accrual includes approximately $185 million for expected remediation costs and associated onsite, offsite and groundwater technical studies and approximately $5 million for related environmental legal costs. Of the $190 million accrual, $16 million was reserved for facilities we currently operate and $174 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 $190 million to approximately $371 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 ($12 million). Second, where the most likely outcome cannot be estimated, a range of costs is established ($178 million to $359 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:

	June 30, 2009	
Sites	**Expected**	**High**
	(In millions)	
Operating	$ 16	$ 23
Non-operating	157	308
Superfund	17	40

Total	$ 190	$ 371

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Below is a reconciliation of our accrued liability from January 1, 2009 to June 30, 2009 (in millions):

Balance as of January 1, 2009	$ 204
Additions/adjustments for remediation activities	7
Payments for remediation activities	(21)
Balance as of June 30, 2009	$ 190

For the remainder of 2009, we estimate that our total remediation expenditures will be approximately $40 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 $8 million in the aggregate for the years 2009 through 2013. 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 31 active sites under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) or state equivalents. We have sought to resolve our liability as a PRP at these sites through indemnification by third parties and settlements, which provide for payment of our allocable share of remediation costs. Because the clean-up costs are estimates and are subject to revision as more information becomes available about the extent of remediation required, and in some cases we have asserted a defense to any liability, our estimates could change. Moreover, liability under the federal CERCLA statute is joint and several, meaning that we could be required to pay in excess of our pro rata share of remediation costs. Our understanding of the financial strength of other PRPs has been considered, where appropriate, in estimating our liabilities. Accruals for these issues are included in the previously indicated estimates for Superfund sites.

It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as 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 Other Contractual Commitments

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.

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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. While many of these agreements may specify a maximum potential exposure, or a specified duration to the indemnification obligation, there are circumstances where the amount and duration are unlimited. For those arrangements with a specified dollar amount, we have a maximum stated value of approximately $794 million, which primarily relates to indemnification arrangements associated with the sale of ANR Pipeline Company in 2007, 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 8. Included in the above maximum stated value are certain indemnification agreements that have expired; however, claims were made prior to the expiration of the related claim periods. We are unable to estimate a maximum exposure of our guarantee and indemnification agreements that do not provide for limits on the amount of future payments due to the uncertainty of these exposures.

As of June 30, 2009, we have recorded obligations of $51 million related to our indemnification arrangements. Our 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 estimated fair value. We have provided a partial parental guarantee of our subsidiary s obligations under this indemnification. We believe that our guarantee and indemnification agreements for which we have not recorded a liability are not probable of resulting in future losses based on our assessment of the nature of the guarantee, the financial condition of the guaranteed party and the period of time that the guarantee has been outstanding, among other considerations.

Commitments, Purchase Obligations and Other Matters. On April 13, 2009, TGP filed an amendment to a 1995 FERC settlement that, if approved by the FERC, would provide for interim refunds to its customers of approximately $157 million of amounts collected related to certain environmental costs. These refunds are recorded as other current and non-current liabilities on our balance sheet and are expected to be paid over a three year period with interest commencing within 20 days after the FERC s order becomes final.

10. Retirement Benefits

Net Benefit Cost (Income). The components of net benefit cost (income) for our pension and postretirement benefit plans for the periods ended June 30 are as follows:

	Quarters Ended June 30,				Six Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
	2009	2008	2009	2008	2009	2008	2009	2008
	(In millions)							
Service cost	$ 4	$ 3	$	$	$ 8	$ 7	$	$
Interest cost	30	30	10	10	60	60	19	17
Expected return on plan assets	(43)	(46)	(3)	(4)	(86)	(93)	(6)	(8)
Amortization of net actuarial loss (gain)	11	6		(1)	22	12		(2)
Amortization of prior service credit				(1)		(1)		(1)
Net benefit cost (income)	$ 2	$ (7)	$ 7	$ 4	$ 4	$ (15)	$ 13	$ 6

Other Matter. In various court rulings prior to March 2008, we were required to indemnify Case for certain benefits paid to a closed group of Case retirees as further discussed in Note 9. 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.

In March 2008, we received a summary judgment from the trial court on this matter, and thus became the primary party that is obligated to pay these benefit payments. As a result of the judgment, we adjusted our obligation using current actuarial assumptions and recorded a $65 million reduction to operation and maintenance expense. We also reclassified this obligation from an indemnification liability to a postretirement benefit obligation.

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11. Equity

Common and Preferred Stock Dividends. The table below shows the amount of dividends paid and declared (dollars in millions, except per share amount):

	Common Stock ($0.05/Share)	Convertible Preferred Stock (4.99%/Year)
Amount paid through June 30, 2009	$ 70	$ 19
Amount paid in July 2009	$ 34	$ 9

Dividends on our common and preferred stock are treated as a reduction of additional paid-in-capital since we currently have an accumulated deficit. For the remainder of 2009, we expect dividends paid on our common and preferred stock will be taxable to our stockholders because we anticipate that these dividends will be paid out of current or accumulated earnings and profits for tax purposes.

The terms of our 750,000 outstanding shares of 4.99% convertible preferred stock provide for the conversion ratio on our preferred stock to increase when we pay quarterly dividends to our common shareholders in excess of $0.04 per share, as we did in January and April 2009. The terms of these preferred shares also 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 we are unable to comply with our fixed charge coverage ratio, our ability to pay additional dividends would be restricted.

Noncontrolling Interests. In June 2009, our subsidiary EPB, a master limited partnership, issued 11 million common units for net proceeds of $184 million. In July 2009, the underwriters of the common unit offering exercised their option to purchase 1.7 million common units for net proceeds of $28 million. Our ownership interest in EPB decreased from 74 percent to 67 percent as a result of the EPB equity offering. EPB makes quarterly distributions of available cash to its unitholders in accordance with its partnership agreement.

In July 2009, EPB acquired an additional 18 percent interest in one of our consolidated subsidiaries, Colorado Interstate Gas Company (CIG), for $215 million. After this acquisition, EPB will own a 58 percent interest in CIG, a 25 percent interest in Southern Natural Gas Company and a 100 percent interest in Wyoming Interstate Company.

12. Business Segment Information

As of June 30, 2009, 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 activities include our general and administrative functions, as well as other miscellaneous businesses and various other 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 June 30, 2009, we conducted our activities primarily through seven wholly or majority owned interstate pipeline systems and equity interests in four transmission systems. In addition to the storage capacity in our wholly and majority owned pipelines systems, we also own or have interests in two underground natural gas storage facilities and two LNG terminalling facilities, one of which is under construction.

Exploration and Production. Engaged in the exploration for and the acquisition, development and production of natural gas, oil and NGL, 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 manages our remaining legacy trading portfolio.

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

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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 our investors because it allows them to evaluate more effectively the operating performance using the same performance measure analyzed internally by our management. We define EBIT as net income (loss) adjusted for items such as (i) interest and debt expense (ii) income taxes and (iii) net income attributable to noncontrolling interests so that our 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 (loss), income (loss) before income taxes and other performance measures such as operating income or operating cash flows. Below is a reconciliation of our EBIT to our net income (loss) for the periods ended June 30:

	Quarters Ended June 30,		Six Months Ended June 30,	
	2009	**2008**	**2009**	**2008**
	(In millions)			
Segment EBIT	$ 377	$ 458	$ (856)	$ 1,019
Corporate and other	31	41	24	80
Interest and debt expense	(253)	(221)	(508)	(454)
Income tax benefit (expense)	(66)	(87)	460	(235)
Net income (loss) attributable to El Paso Corporation	89	191	(880)	410
Net income attributable to noncontrolling interests	11	7	23	16
Net income (loss)	$ 100	$ 198	$ (857)	$ 426

The following table reflects our segment results for the periods ended June 30:

	Segments					
	Pipelines	**Exploration and Production**	**Marketing**	**Power**	**Corporate and Other[1]**	**Total**
	(In millions)					
Quarter Ended June 30, 2009						
Revenue from external customers	$ 639	$ 185(2)	$ 148	$	$ 1	$ 973
Intersegment revenue	11	124(2)	(133)		(2)	
Operation and maintenance	195	90	4	4	(29)	264
Ceiling test charges		12				12
Depreciation, depletion and amortization	102	91			4	197
Earnings (losses) from unconsolidated affiliates	25	(13)		(1)	1	12
EBIT	327	61	10	(21)	31	408
Quarter Ended June 30, 2008						
Revenue from external customers	$ 632	$ 198(2)	$ 322	$	$ 1	$ 1,153
Intersegment revenue	14	457(2)	(468)		(3)	
Operation and maintenance	205	98	8	4	(40)	275
Ceiling test charges		7				7
Depreciation, depletion and amortization	99	197			2	298

Earnings from unconsolidated affiliates	25	16		11		52
EBIT	295	304	(153)	12	41	499

(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 June 30, 2009 and 2008, we recorded an intersegment revenue elimination of $2 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.

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	Segments					
	Pipelines	Exploration and Production	Marketing	Power	Corporate and Other[1]	Total
			(In millions)			
Six Months Ended June 30, 2009						
Revenue from external customers	$1,360	$ 759(2)	$ 336	$	$ 2	$2,457
Intersegment revenue	23	250(2)	(268)		(5)	
Operation and maintenance	378	199	5	6	(24)	564
Ceiling test charges		2,080				2,080
Depreciation, depletion and amortization	206	241			6	453
Earnings (losses) from unconsolidated affiliates	46	(22)		5	2	31
EBIT	723	(1,624)	62	(17)	24	(832)
Six Months Ended June 30, 2008						
Revenue from external customers	$1,339	$ 328(2)	$ 744	$	$ 11	$2,422
Intersegment revenue	27	930(2)	(947)		(10)	
Operation and maintenance	400	206	10	9	(79)	546
Ceiling test charges		7				7
Depreciation, depletion and amortization	198	409			4	611
Earnings from unconsolidated affiliates	46	26		16	1	89
EBIT	676	546	(213)	10	80	1,099

(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 six months ended June 30, 2009 and 2008, we recorded an intersegment revenue elimination of $5 million and $10 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:

	June 30, 2009	December 31, 2008
	(In millions)	
Pipelines	$ 16,081	$ 15,121
Exploration and Production	3,993	6,142
Marketing	281	465
Power	220	417
Total segment assets	20,575	22,145
Corporate and Other	1,068	1,523
Total consolidated assets	$ 21,643	$ 23,668

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13. 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			
			Quarters Ended		Six Months Ended	
	June 30, 2009	December 31, 2008	June 30, 2009	June 30, 2008	June 30, 2009	June 30, 2008
	(In millions)		(In millions)			
Net Investment and Earnings (Losses)						
Four Star [1]	$ 480	$ 525	$ (12)	$ 16	$ (22)	$ 26
Citrus	598	564	20	19	34	32
Gulf LNG[2]	288	279	(1)		(1)	
Gasoductos de Chihuahua	171	174	6	6	12	13
Porto Velho[3]		(64)				
Bolivia-to-Brazil Pipeline	114	119	(5)	3	(1)	6
Argentina to Chile Pipeline[4]		27	2	2	4	3
Other	73	79	2	6	5	9
Total	$ 1,724	$ 1,703	$ 12	$ 52	$ 31	$ 89

(1) Amortization of our purchase cost in excess of the underlying net assets of Four Star was $13 million for each of the quarters ended June 30, 2009 and 2008 and $25 million and $27 million for the six months ended June 30, 2009 and 2008.

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

(3) As of December 31, 2008, we had outstanding advances and receivables of $242 million, not included above, related to our investment in Porto

Velho. During 2009, we completed the sale of our investment in and receivables from Porto Velho as further discussed in *Other Investment-Related Matters* below.

(4) In June 2009, we completed the sale of our investment in the Argentina to Chile Pipeline as further discussed in *Other Investment-Related Matters* below.

	Quarters Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(In millions)			
Summarized Financial Information				
Operating results data:				
Operating revenues	$ 135	$ 194	$ 258	$ 380
Operating expenses	69	84	137	177
Income from continuing operations and net income	24	66	59	122

As of December 31, 2008, approximately $433 million of the equity in undistributed earnings of 50 percent or less owned entities accounted for by the equity method was included in our consolidated accumulated deficit. We received distributions and dividends from our unconsolidated affiliates of $24 million and $21 million for the quarters ended June 30, 2009 and 2008 and $36 million and $81 million for the six months ended June 30, 2009 and 2008. Included in these amounts are returns of capital of $1 million or less than $1 million for the quarters and six months ended June 30, 2009 and 2008. Our revenues and charges with unconsolidated affiliates were not material during the quarters and six months ended June 30, 2009 and 2008.

Accounts Receivable Sales Program. Several of our pipeline subsidiaries have agreements to sell certain accounts receivable to QSPEs whose purpose is solely to invest in our pipeline receivables which are short-term assets that generally settle within 60 days. During the quarter and six months ended June 30, 2009, we received net proceeds of approximately $0.4 billion and $1.0 billion related to sales of receivables to the QSPEs, and changes in our subordinated beneficial interests, and recognized losses of less than $1 million on these transactions. As of June 30, 2009 and December 31, 2008, we had approximately $146 million and $174 million of receivables outstanding with the QSPEs, for which we received cash of $76 million and $82 million and received subordinated beneficial interests of approximately $70 million and $89 million. The QSPEs also issued senior beneficial interests on the receivables sold to a third party financial institution, which totaled $76 million and $85 million as of June 30, 2009 and December 31, 2008. We reflect the subordinated beneficial interest in receivables sold at their fair value on the date they are issued. These amounts (adjusted for subsequent collections) are recorded as accounts receivable from affiliates in our balance sheet. Our ability to recover the carrying value of our subordinated beneficial interests is based on the collectibility of the underlying receivables sold to the QSPEs. We reflect accounts receivable sold under this program and changes in the subordinated beneficial interests as operating cash flows in our statement of cash flows. Under the agreements, we earn a fee for servicing the accounts receivable and performing all administrative duties for the QSPEs which is reflected as a reduction of operation and maintenance expense in our income statement. The fair value of these servicing and administrative agreements as well as the fees earned were not material to our financial statements for the periods ended June 30, 2009 and 2008.

Other Investment-Related Matters

Porto Velho. In February 2009, we completed the sale of our interests in Porto Velho to our partner in the project for $101 million of cash and $78 million of notes receivable from the buyer. In May 2009, we sold the notes receivable, including accrued interest, to a third party for $57 million and recorded a loss of approximately $22 million in other expenses in our Power segment.

Manaus/Rio Negro. In 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 June 30, 2009, we have approximately $59 million of Brazilian reais-denominated 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 Brazilian reais-denominated claims of approximately $57 million related to plant maintenance the purchaser claims should have been performed at the plants prior to the transfer, inventory levels and other items. Settlement discussions with the purchaser have ceased and we have initiated regulatory proceedings to allow us to resolve these outstanding claims and recover our accounts receivable. We also initiated legal action against the purchaser s parent in the second quarter of 2009 for their failure to pay us under the performance guaranty. 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, and 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.

During 2009, the Brazilian taxing authorities began legal proceedings against the Manaus and Rio Negro projects for $47 million of ICMS taxes allegedly due on capacity payments received from the plants power purchaser from 1999 to 2001. By agreement, the power purchaser must indemnify the Manaus and Rio Negro projects for these ICMS taxes, along with related interest and penalties, and has therefore been defending the projects against this lawsuit. In order to continue its defense of this matter, the power purchaser is required to provide security for the potential tax liability to the court s satisfaction. The power purchaser offered to pledge certain assets, but this offer was rejected by the tax authorities and the court. The power purchaser is now considering other forms of security to offer to the court. If the power purchaser is unable to resolve these tax matters, any potential taxes owed by the Manaus and Rio Negro projects are also guaranteed by the purchaser s parent.

Investments in Bolivia and Argentina. We own an 8 percent interest in the Bolivia-to-Brazil pipeline. As of June 30, 2009, our total investment and guarantees related to this pipeline project was approximately $126 million. We continue to monitor and evaluate the potential impact that regional and political events in Bolivia could have on our investment in this pipeline project, as further discussed in our 2008 Annual Report on Form 10-K. As new information becomes available or future material developments arise, we may be required to record an impairment of our investment. In June 2009, we completed the sale of our investment in the Argentina-to-Chile pipeline to our partners for approximately $32 million.

14. Subsequent Events

Ruby Pipeline. In July 2009, we entered into a binding agreement with several infrastructure funds managed by Global Infrastructure Partners, whereby they committed to invest up to $700 million in a holding company for our Ruby pipeline project (Ruby) subject to the satisfaction of certain conditions. This commitment is comprised of three components: (i) a $405 million loan commitment that is convertible into preferred equity of Ruby; (ii) a $145 million commitment to invest in a convertible preferred equity interest in Ruby that is exchangeable for a convertible preferred equity interest in a holding company of one of our consolidated subsidiaries, Cheyenne Plains Gas Pipeline Company that converts back into convertible preferred equity of Ruby upon satisfaction of certain conditions, including placing the Ruby pipeline into service; and (iii) a commitment to invest in an additional convertible preferred equity interest in Ruby of up to $150 million.

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

The information contained in Item 2 updates, and you should read it in conjunction with, information disclosed in our 2008 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 and Outlook

During the first six months of 2009, our pipeline operations continued to provide a strong base of earnings and operating cash flow. In our pipeline business, approximately three-fourths of the revenues are collected in the form of demand or reservation charges which are not dependent upon commodity prices or throughput levels. We remain focused on implementing our backlog of committed pipeline growth projects and have placed two projects in-service during 2009.

In our exploration and production business, we continued to generate significant positive operating cash flow during the quarter despite a low commodity price environment, principally as a result of derivatives we have in place related to our 2009 production. As of June 30, 2009, we had 80 TBtu of natural gas hedges with an average floor price of $9.02 per MMBtu, 64 TBtu of natural gas hedges with an average ceiling price of $14.35 per MMBtu and 902 MBbls of crude oil swaps at $45 per barrel on our remaining anticipated 2009 production. However, lower natural gas prices at the end of the first quarter of 2009 resulted in approximately $2.1 billion of non-cash ceiling test charges, primarily in our domestic full cost pool, which significantly impacted our overall results for that quarter and the first six months of 2009. As a result of improved commodity prices and lower costs at June 30, 2009, we did not have a ceiling test charge in our domestic or Brazilian full cost pools during the second quarter of 2009. Subsequent to June 30, 2009, however, commodity prices have declined, and as such we may be required to record additional ceiling test charges in the future.

In both of our core businesses, we have implemented various cost saving measures to reduce our capital, operating, and general and administrative costs. These measures include reducing drilling activity in our exploration and production business until oilfield service costs decrease to a level commensurate with commodity prices, realizing cost reductions in our capital and maintenance programs by renegotiating contracts with contractors, suppliers and service providers, and deferring and eliminating various discretionary costs.

The volatility in the financial markets, the energy industry and the global economy is expected to continue for the remainder of 2009 and possibly beyond. This could impact our longer-term access to capital for future growth projects as well as the cost of such capital, and may require us to further adjust our current financing and business plans. Additionally, commodity prices for natural gas and oil have been and are expected to remain volatile, and although we have attempted to mitigate the effects of these reductions in commodity prices by entering into derivative contracts on our natural gas and oil production, we still have a portion of our production subject to the current lower commodity price environment as further described below. Finally, while the impacts are difficult to quantify, a continued downward trend in the global economy could have adverse impacts on natural gas consumption and demand over time. All of these factors may impact our outlook for the remainder of 2009 and beyond.

As of June 30, 2009, we had approximately $2.3 billion of available liquidity (see *Liquidity and Capital Resources)*, after repayment of $0.9 billion in outstanding debt obligations that matured in May 2009. We have designed our 2009 plans to address the impacts of current volatility in the global financial markets and based on our activities to date, we do not anticipate a need to further access the capital markets to fund our 2009 capital program. When prudent, we will continue to be opportunistic in building liquidity to meet our long-term capital needs; however, there are no assurances that we will be able to continue to access the financial markets to fund our long-term capital needs. Our 2009 plans are also designed to retain our long-term growth potential, including our committed pipeline project backlog and our core domestic and international drilling programs, as well as our natural gas and oil resource positions. In light of the current volatility of the financial markets, the energy industry and the global economy, it is possible additional adjustments to our plan and outlook will be required which could impact our financial and operating performance.

Currently, these plans include:

Capital Expenditures. Planned 2009 capital expenditures of approximately $3.2 billion, with $2.1 billion of capital being spent in our pipeline business and approximately $1.0 billion in our exploration and production business (see *Liquidity and Capital Resources*).

In our pipeline business, in July 2009, we entered into a binding agreement with several infrastructure funds managed by Global Infrastructure Partners (GIP), whereby they will invest up to $700 million in our Ruby pipeline project in the following three major tranches (i) a loan of $405 million to be advanced as a series of loans on and after the initial closing (which is expected to occur in August 2009), which would be converted into preferred equity in a holding company for the Ruby pipeline project (Ruby) upon satisfaction of certain conditions, (ii) $145 million contributed in or around October 2009 as a convertible preferred equity interest in Ruby that may be simultaneously exchanged for a convertible preferred equity interest in a holding company of Cheyenne Plains Gas Pipeline (Cheyenne Plains) and (iii) up to an additional $150 million contributed at the time of financing closing to the extent required. The convertible preferred equity interest in Ruby will earn a 13 percent yield beginning at final project completion. GIP will have the right to convert its preferred equity to common equity at any time. However, the preferred equity is subject to a mandatory conversion to common equity upon the satisfaction of certain conditions, including Ruby entering into additional firm transportation agreements.

If all conditions to closing are satisfied or waived, then at the time of project completion, GIP would own a 50% equity interest in Ruby and all ownership in Cheyenne Plains would be transferred back to us. We will provide security for GIP s investment until the completion of the Ruby Pipeline project that will include a portion of our approximately 55 million El Paso Pipeline Partners, L.P. common units, our equity interest in Ruby and our equity interest in Cheyenne Plains. If the closings associated with the project financing or the project completion do not occur by certain dates, there are provisions in the agreements to unwind the transactions, including the repayment of the loan and the redemption of GIP s interests in Ruby and Cheyenne Plains with a return on its investment. Additionally, if such closings do not occur, then GIP has the option to retain a 50% common interest in Cheyenne Plains.

In our exploration and production business, although it will also impact our near-term growth profile in this business, the objective of reductions in our capital program is to retain substantially all of our existing natural gas and oil resource positions for future exploration and production when commodity prices and oilfield service costs return to more favorable levels.

Asset Sales. We have sold or are evaluating the sale of several non-core assets generating cash proceeds of approximately $0.3 billion in 2009, nearly all of which have already been completed.

Other Liquidity Sources. We will continue to be opportunistic in generating additional liquidity, which may include additional asset sales or additional partnering opportunities on expansion projects. To the extent these opportunities are delayed or cannot be completed, there is a further decline in commodity prices or we experience other major disruptions in the financial markets, we could also pursue other alternatives, including additional reductions in our discretionary capital program, further reductions in operating and general and administrative expenses, additional financing arrangements, seeking additional partners for other growth projects or selling additional non-core assets.

Our plans were determined based on a number of factors, the most significant of which are described below and in further detail in our 2008 Annual Report on Form 10-K:

Debt Capital Structure. Our debt capital structure is 84 percent fixed interest rates and 16 percent floating interest rates. Accordingly, we believe we have lessened exposure to market changes in interest rates on our existing debt which impact our interest costs.

Revenue and Price Sensitivities. As previously discussed, we have mitigated our sensitivity to commodity prices with approximately three-fourths of our pipeline revenues collected in the form of demand or reservation charges and through derivative contracts in our exploration and production business. As noted above, we have significant derivative contracts in place for our 2009 natural gas and oil production. We have also entered into derivative contracts on a substantial portion of our anticipated 2010 and 2011 natural

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gas production to mitigate exposure to low commodity prices; however, we continue to have some commodity price exposure remaining. Finally, in the event of lower oil or natural gas prices, we currently have unencumbered exploration and production properties and reserves that we could pledge as additional collateral towards the revolving credit facilities at our exploration and production subsidiary should this be necessary based on revaluation of our borrowing base under this facility in November 2009.

Counterparty Risk. We continue to monitor the financial situation of our major lenders, derivative counterparties, customers, joint interest partners, vendors and suppliers, and enforce our contractual rights with regard to obtaining collateral or providing credit.

Lending Institutions. As of June 30, 2009, we have determined the potential exposure to a loss of available capacity under our credit agreements, due to our assessment of our lenders ability to fund, to be approximately $31 million from El Paso s $1.5 billion revolving credit facility, approximately $2 million from EPEP s $1.0 billion revolving credit facility, and approximately $15 million under EPB s $750 million credit facility.

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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 power and pipeline assets in South America and Asia. 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 our 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 items such as (i) interest and debt expense, (ii) income taxes and (iii) net income attributable to noncontrolling interests so that our 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 (loss), income (loss) before income taxes and other performance measures such as operating income or operating cash flows.

Below is a reconciliation of our EBIT (by segment) to our consolidated net income (loss) for the periods ended June 30:

	Quarters Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(In millions)			
Segment				
Pipelines	$ 327	$ 295	$ 723	$ 676
Exploration and Production	61	304	(1,624)	546
Marketing	10	(153)	62	(213)
Power	(21)	12	(17)	10
Segment EBIT	377	458	(856)	1,019
Corporate and other	31	41	24	80
Consolidated EBIT	408	499	(832)	1,099
Interest and debt expense	(253)	(221)	(508)	(454)
Income tax benefit (expense)	(66)	(87)	460	(235)
Net income (loss) attributable to El Paso Corporation	89	191	(880)	410
Net income attributable to noncontrolling interests	11	7	23	16
Net income (loss)	$ 100	$ 198	$ (857)	$ 426

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Pipelines Segment

Overview and Operating Results. During the first six months of 2009, we continued to deliver strong operational and financial performance across all pipelines. Our EBIT for the quarter and six months ended June 30, 2009 increased 11 percent and 7 percent from the same periods for 2008. In the first six months of 2009, we benefited from several expansion projects placed in service in 2008. Below are the operating results for our Pipelines segment as well as a discussion of factors impacting EBIT for the periods ended June 30, 2009 and 2008, or that could potentially impact EBIT in future periods.

	Quarters Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(In millions, except for volumes)			
Operating revenues	$ 650	$ 646	$ 1,383	$ 1,366
Operating expenses	(365)	(383)	(731)	(746)
Operating income	285	263	652	620
Other income, net	53	40	94	73
EBIT before adjustment for noncontrolling interests	338	303	746	693
Net income attributable to noncontrolling interests	(11)	(8)	(23)	(17)
EBIT	$ 327	$ 295	$ 723	$ 676
Throughput volumes (BBtu/d)[1]	17,929	17,981	18,817	18,652

(1) Throughput volumes include our proportionate share of unconsolidated affiliates and exclude intrasegment activities.

	Quarter Ended June 30, 2009 Variance				Six Months Ended June 30, 2009 Variance			
	Operating Revenue	Operating Expense	Other	EBIT Impact	Operating Revenue	Operating Expense	Other	EBIT Impact
	Favorable/(Unfavorable) (In millions)							
Expansions	$ 20	$ (5)	$ 13	$ 28	$ 39	$ (11)	$ 21	$ 49
Reservation and usage revenues	3			3	30			30
Gas not used in operations and revaluations	(7)	17		10	(7)	11		4
Bankruptcy settlements	(12)	(2)		(14)	(41)	(2)		(43)
Loss on long-lived assets		8		8		24		24
Hurricanes		(2)		(2)		(5)		(5)
			(3)	(3)			(6)	(6)

Net income attributable to noncontrolling interests								
Other[1]		2		2	(4)	(2)		(6)
Total impact on EBIT	$ 4	$ 18	$ 10	$ 32	$ 17	$ 15	$ 15	$ 47

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

Expansions. During 2009, we benefited from increased reservation revenues and throughput volumes due to projects placed in-service throughout 2008 including the Kanda lateral project, the Medicine Bow expansion and the High Plains Pipeline.

We continue to make progress on our backlog of expansion projects and have placed two projects in-service during the second quarter of 2009. We have spent $0.6 billion during the six months ended June 30, 2009. Our backlog of expansion projects are substantially fully contracted with customers and will be placed in-service over the next five years. In addition, financings have been completed to fund our $1.7 billion expansion capital plan in 2009 and a substantial portion of the capital needs for the Gulf LNG and Florida Gas Transmission Phase VIII projects. Over the next twelve months, we expect several projects to be placed in-service representing $0.9 billion of the expansion backlog.

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Additionally, listed below are significant updates to our December 31, 2008 backlog of projects originally discussed in our 2008 Annual Report on Form 10K.

Colorado Interstate Gas Company (CIG) Raton 2010 Expansion. During the first quarter of 2009, we agreed with our customers to defer the in-service date for our Raton 2010 project from June 2010 to December 2010.

Totem Gas Storage. In June 2009, our Totem Gas Storage project was placed in-service.

TGP 300 Line Expansion. In July 2009, we filed an application with the FERC for certificate authorization for our 300 Line Expansion project.

Ruby Pipeline Project. In June 2009, the FERC issued a draft Environmental Impact Study. A final environmental impact statement is scheduled to be issued in October 2009. Final sizing of the project will be based on market support. In July 2009, we entered into a binding agreement with GIP, whereby they will invest up to $700 million in the Ruby pipeline project as further discussed in *Overview and Outlook* above.

Elba Expansion III/ Elba Express/ Cypress Phase III. On June 25, 2009, BG LNG Services LLC (BG) and SNG, Elba Express (EEC) and Southern LNG, Inc. entered into agreements to delay the in-service date of the Elba III Phase B expansion project. The modified agreements give BG the option to delay the in-service date of the Elba III Phase B expansion to as late as the end of 2015, or, in the event certain conditions are unable to be met by BG, to terminate the Elba III Phase B expansion. In exchange for allowing this delay/termination option, BG has committed to subscribe to certain firm Phase B capacity on El Paso s Elba Express pipeline and to potentially provide certain rate considerations on an existing transportation contract on El Paso s SNG Pipeline. In addition, BG has given up its right to proceed with Phase III of the Cypress Expansion Project on SNG.

In addition to our backlog of contracted organic growth projects, we have other projects that are in various phases of commercial development, two of which are noted below. Many of the potential projects involve expansion capacity to serve increased natural gas-fired generation loads, as well as new supply projects.

Potential Power Plant Loads. SNG has executed a non-binding letter of intent with Florida Power & Light (FPL) to expand SNG s system by approximately 600 MMcf/d by constructing approximately 375 miles of 36-inch pipeline from western Alabama to northern Florida. The expansion is currently estimated to cost approximately $1.4 billion to $1.6 billion and would serve, in part, two oil-fired power plants that FPL plans to convert to natural gas usage. However, Southern Union (a 50% owner of Florida Gas Transmission along with us) has alleged that SNG does not have the right to participate in the project.

Along the Front Range of CIG s system, utilities have various projects under development that involve constructing new natural gas-fired generation in part to provide backup capacity required when renewable generation is not available during certain daily or seasonal periods.

Potential Supply Projects. TGP s system is located over a significant portion of the Marcellus Basin that is under various phases of development by producers. TGP has executed firm transportation contracts with shippers from the basin utilizing its existing capacity. In addition, TGP has been in discussions with producers to expand its system to provide additional transportation capacity from the Marcellus Basin.

Most of our potential expansion projects would have in-service dates for 2014 and beyond. If we are successful in contracting for these new projects, the capital requirements could be substantial and would be incremental to our backlog of contracted organic growth projects. Although we pursue the development of these potential projects from time to time, there can be no assurance that we will be successful in negotiating the definitive binding contracts necessary for such projects to be included in our backlog of contracted organic growth projects.

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Reservation and Usage Revenues. During the quarter and six months ended June 30, 2009, our overall EBIT was favorably impacted by (i) increased reservation and other services revenues on our EPNG system during the first six months of 2009 primarily resulting from higher contracted capacity to primary delivery points in California and an increase in EPNG s tariff rates effective January 1, 2009, subject to refund, which was partially offset by decreased usage revenues primarily due to reduced throughput in 2009, (ii) increased revenues for the mainline and lateral capacity on our Rocky Mountain region systems primarily due to new contracts and restructured contract terms and (iii) additional capacity sales in the southern, central, and northern regions of our TGP system.

For the six months ended June 30, 2009, our throughput volumes on our TGP and EPNG systems decreased compared with the same period in 2008. This was due, in part, to general weakness in natural gas demand in the United States, including in the southwest and northeast. Although fluctuations in throughput on our pipeline systems have a limited effect on our short-term results since a material portion of our revenues are derived from firm reservation charges, it can be an indication of the risks we may face when seeking to recontract or renew any of our existing firm transportation contracts. Continuing negative economic impacts on demand, as well as adverse shifting of sources of supply, could negatively impact basis differentials and our ability to renew firm transportation contracts that are expiring on our system or our ability to renew such contracts at current rates. If we determine there is a significant change in our costs or billing determinants on any of our pipeline systems, we will have the option to file rate cases with the FERC to recover our prudently incurred costs.

Gas Not Used in Operations and Revaluations. During the six months ended June 30, 2009, our revenue was favorably impacted by approximately $15 million primarily due to higher average prices realized on operational sales of gas not used in our TGP system, partially offset by $5 million related to replacement of depleted storage volumes in our SNG system, among other items.

In addition, during the six months ended June 30, 2008, we recorded fuel cost and revenue tracker adjustments associated with the implementation of FERC-approved fuel and related gas cost recovery mechanisms by CIG and Wyoming Interstate Company during 2008. The implementation of these mechanisms was protested by a limited number of shippers. On July 31, 2009, the FERC issued an order on rehearing that effectively unwound the non-volumetric provisions of CIG s fuel and gas cost recovery mechanism, which we believe could expose us to both positive and negative fluctuations in gas prices in the future. This price volatility may impact our earnings through the periodic non-cash revaluation of our fuel imbalances and their eventual cash settlement, along with other impacts to related gas balance items. We are currently evaluating the impact of this order on our fuel recovery mechanism, and have not yet determined if we will file for a judicial appeal of the FERC rehearing order.

Bankruptcy Settlements. During the quarter and six months ended June 30, 2008, we recognized revenue of $6 million and $35 million related to distributions received under Calpine Corporation s approved plan of reorganization. This settlement was related to Calpine s rejection of its transportation contracts with us. During the second quarter of 2008, we recorded income of approximately $8 million as a result of settlements received from the Enron Corporation bankruptcy.

Loss on Long-Lived Assets. During the quarter and six months ended June 30, 2008, we recorded impairments of $8 million and $24 million, primarily related to our Essex-Middlesex Lateral project due to a prolonged permitting process.

Hurricanes. We continue to repair damages to sections of our Gulf Coast and offshore pipeline facilities due to Hurricanes Ike and Gustav which occurred in 2008. For the quarter and six months ended June 30, 2009, our EBIT was unfavorably impacted by repair costs that will not be recoverable from insurance due to losses not exceeding self-retention levels. See *Liquidity and Capital Resources* for a further discussion of these hurricanes.

Net Income Attributable to Noncontrolling Interests. During the quarter and six months ended June 30, 2009, our net income attributable to noncontrolling interests increased as compared to the same period in 2008 due to the additional contribution of interests in CIG and SNG to our majority-owned master limited partnership during September 2008.

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Other Regulatory Matters. Our pipeline systems periodically file for changes in their rates, which are subject to the approval of the FERC. Changes in rates and other tariff provisions resulting from these regulatory proceedings have the potential to 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 late 2009 through 2011.

In June 2008, EPNG filed a rate case with the FERC as required under the settlement of its previous rate case. The filing proposed an increase in EPNG s base tariff rates. In August 2008, the FERC issued an order accepting the proposed rates effective January 1, 2009, subject to refund and the outcome of a hearing and a technical conference. The FERC issued an order in December 2008 that generally accepted most of EPNG s proposals in the technical conference proceeding. The FERC has appointed an administrative law judge to preside over a hearing if EPNG is unable to reach a negotiated settlement with its customers on the remaining issues. The hearing is currently scheduled to begin in late October 2009. The outcome of the hearing is not currently determinable.

In March 2009, SNG filed a rate case with the FERC as permitted under the settlement of its previous rate case. The filing proposed an increase in SNG s base tariff rates. In April 2009, the FERC issued an order accepting the proposed rates effective September 1, 2009, subject to refund and the outcome of a hearing and a technical conference on certain tariff proposals. The FERC has appointed an administrative law judge to preside over a hearing if SNG is unable to reach a negotiated settlement with its customers on the remaining issues. The hearing is currently scheduled to begin in February 2010. The outcome of the hearing is not currently determinable.

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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 of 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, executing to improve capital and expense efficiency, and maximizing returns by adding assets and inventory that match our competencies and divesting assets that do not. For a further discussion of our business strategy in our production business, see our 2008 Annual Report on Form 10-K.

Our domestic natural gas and oil reserve portfolio blends lower decline rate, typically longer lived assets in our Central and Western divisions, with steeper decline rate, shorter lived assets in our Gulf Coast division. In May 2009, we reorganized our domestic exploration and production operations to combine our Texas Gulf Coast and Gulf of Mexico and south Louisiana regions into the Gulf Coast division.

Internationally, our portfolio consists of producing fields along with several exploration and development projects in offshore Brazil and exploration projects in Egypt. Success of our international programs in Brazil and Egypt will require effective project management, strong partner relations and obtaining approvals from regulatory agencies, although current economic conditions may dictate the timing of our spending. In Egypt, in the first half of 2009, we exchanged a 40 percent working interest in our South Mariut block for an equal working interest in the Tanta block. In addition, in early July 2009, we completed the acquisition of a 50 percent working interest in the South Alamein block located in the Western Desert. These transactions expand our acreage position and diversify our portfolio in Egypt.

During the first quarter of 2009, the industry experienced continued reductions in the market price of natural gas from already reduced levels at December 31, 2008. Furthermore, service and equipment costs declined, but not at levels commensurate with the reduction in commodity prices. Based on reduced commodity prices and service equipment costs as of March 31, 2009, we recorded non-cash ceiling test charges of approximately $2.1 billion during the first quarter of 2009. As of June 30, 2009, commodity prices had improved from March 31, 2009 levels. However, the challenging commodity price environment continues to put pressure on our economic assumptions related to development and exploration in 2009. Coupled with unprecedented challenges in the credit markets, these events resulted in us reducing our capital spending in 2009. Based on these lower spending levels, we expect our 2009 production volumes to be down from two percent to ten percent compared to 2008.

Significant Operational Factors Affecting the Periods Ended June 30, 2009

Production. Our average daily production for the six months ended June 30, 2009 was 717 MMcfe/d (which does not include 73 MMcfe/d from our share of production from our equity investment in Four Star). Below is an analysis of our production volumes by division for the periods ended June 30:

	Six Months Ended June 30,	
	2009	**2008**
	MMcfe/d	
United States		
Central	249	239
Western	163	151
Gulf Coast	296	384
International		
Brazil	9	12
Total Consolidated	717	786
Four Star	73	73

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In the first six months of 2009, production volumes increased in our Central and Western divisions. Central division production volumes increased as a result of our successful Arklatex drilling programs including the Haynesville Shale, while our Western division production volumes increased in the Rockies. In our Gulf Coast division, production volumes decreased primarily due to sales of assets in 2008 and 2009 and impacts of Hurricanes Ike and Gustav. In Brazil, our production volumes decreased primarily due to natural production declines.

2009 Drilling Results

Our drilling results for the six months ended June 30, 2009 by division are as follows:

Central. We achieved a 100 percent success rate on 71 gross wells drilled.

Western. We achieved a 100 percent success rate on three gross wells drilled.

Gulf Coast. We achieved an 82 percent success rate on 22 gross wells drilled.

Brazil. Our drilling operations in Brazil are primarily in the Camamu and Espirito Santo Basins.

Camamu Basin. During the first six months of 2009, we continued the process of obtaining regulatory and environmental approvals that are required to enter the next phase of development in the Pinauna Field. The timing of the Pinauna Field development will be dependent on the receipt of these approvals and either the recovery of commodity prices or cost reductions that reflect the current low commodity price environment.

In the BM-CAL-6 block, following the drilling of an unsuccessful exploratory well in 2008 and completion of our evaluation of the block, we relinquished our interest in this block in July 2009. In the BM-CAL-5 block, we are evaluating the results of two exploratory wells, one drilled in late 2008 and the other during 2009, where hydrocarbons were discovered. In addition, we own a 20 percent interest in two additional blocks in the Camamu basin, CAL-M-312 and 372, which are located east of and contiguous to the BM-CAL-5 and 6 blocks. We will be further evaluating these two blocks over the next year.

Espirito Santo Basin. We continue to execute the plan of development for the Camarupim Field. As of June 30, 2009, four horizontal natural gas wells have been drilled and three have been tested. Petrobras, the operator, estimates production from the field will begin in August 2009.

In early 2009, we completed drilling an exploratory well with Petrobras in the ES-5 block in the Espirito Santo Basin in which we own a 35 percent working interest. Hydrocarbons were found in the well and we are now evaluating the results. During the fourth quarter of 2009, we plan to participate with Petrobras in drilling another exploratory well in the ES-5 block to evaluate an additional prospect.

During the first six months of 2009, we added approximately 81 Bcfe of reserves in Brazil and, as of June 30, 2009, have total capitalized costs of approximately $310 million, of which $177 million are unevaluated capitalized costs.

Egypt. In 2009, we completed drilling two exploratory wells in the South Mariut block that were unsuccessful and recorded charges totaling $21 million in our full cost pool, including $12 million in the second quarter of 2009. In addition, CEPSA Egypt S.A. B.V., the operator of the South Alamein block, completed drilling the first well in the block, which found hydrocarbons and is currently being evaluated. We are currently participating with CEPSA in drilling the second exploratory well on the block with plans to drill a third exploratory well in the block by the end of 2009. As of June 30, 2009, we have total capitalized costs of approximately $21 million in Egypt, all of which are unevaluated capitalized costs.

Cash Operating Costs. We monitor cash operating costs required to produce our natural gas and oil production volumes. Cash operating costs is a non-GAAP measure calculated on a per Mcfe basis and includes total operating expenses less depreciation, depletion and amortization expense, ceiling test or impairment charges, transportation costs and cost of products. Cash operating costs per unit is a valuable measure of operating performance and efficiency for the exploration and production segment.

During the six months ended June 30, 2009, cash operating costs per unit decreased to $1.85/Mcfe as compared to $1.96/Mcfe during the same period in 2008 primarily due to lower lease operating expenses and production taxes partially offset by lower production volumes in 2009 versus 2008.

Capital Expenditures. Our total natural gas and oil capital expenditures were $547 million for the six months ended June 30, 2009, of which $414 million were domestic capital expenditures.

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Outlook for 2009

For the full year 2009, we expect the following on a worldwide basis:

Capital expenditures, excluding acquisitions, of approximately $1.0 billion. Of this total, we expect to spend $0.7 billion on our domestic program and approximately $250 million in Brazil and Egypt.

Average daily production volumes for the year of approximately 665 MMcfe/d to 730 MMcfe/d, which does not include approximately 65 MMcfe/d to 70 MMcfe/d from our equity investment in Four Star. Production volumes from our Brazil operations are expected to increase from an average of about 11 MMcfe/d in 2008 to between 25 MMcfe/d and 30 MMcfe/d in 2009, with production volumes from the Camarupim Field expected to commence in August 2009.

Average cash operating costs which include production costs, general and administrative expenses and other expenses of approximately $1.95/Mcfe to $2.15/Mcfe for the year.

Depreciation, depletion and amortization rate of between $1.70/Mcfe and $1.80/Mcfe, which includes the impact of our first quarter 2009 ceiling test charges.

Price Risk Management Activities

We enter into derivative contracts on our natural gas and oil production to stabilize cash flows, 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 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 half of 2009, we settled all of our $110.00 per barrel 2009 fixed price oil swaps and received approximately $186 million in cash and entered into new fixed price oil swaps on 1,500 MBbls of our remaining anticipated 2009 oil production at an average price of $45.00 per barrel. We also entered into additional natural gas option and basis swap contracts on our 2009, 2010 and 2011 production. During the first half of 2009, we paid $173 million in premiums to enter into financial derivative contracts related to our 2010 and 2011 natural gas production. The following table reflects the contracted volumes and the minimum, maximum and average prices we will receive under our derivative contracts as of June 30, 2009.

	Fixed Price Swaps(1)		Floors(1)		Ceilings(1)		Basis Swaps(1)(2)							
									Western				Central	
							Texas Gulf Coast		Raton		Rockies		Mid-Continent	
	Volumes	Average Price	Volumes	Average Price	Volumes	Average Price	Volumes	Average Price	Volumes	Average Price	Volumes	Average Price	Volumes	Average Price
Natural Gas														
2009	4	$ 7.37	76	$9.11	60	$14.83	29	$(0.34)	12	$(0.96)	6	$(2.01)	5	$(1.04)
2010	52	$ 6.19	123	$6.50	60	$ 8.14	47	$(0.40)	20	$(0.78)	9	$(1.93)	9	$(0.74)
2011	16	$ 5.99	120	$6.00	120	$ 9.00								
2012	2	$ 3.93												
Oil														
2009	902	$45.00												

(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.

Internationally, our natural gas sales agreement for our production from the Camarupim Field in Brazil provides for a price that is adjusted quarterly based on a basket of fuel oil prices. In addition to the amounts included in the table above, as of June 30, 2009, we had entered into fuel oil swaps which effectively lock in a price of approximately $4.00 per MMBtu on approximately 8 TBtu of projected Brazilian natural gas production in 2010.

In August 2009, we entered into 366 MBbls of fixed price swaps on our anticipated 2009 oil production at an average price of $75.23/bbl.

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Operating Results and Variance Analysis

The information below provides the financial results and an analysis of significant variances in these results during the quarters and six months ended June 30:

	Quarters Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(In millions)			
Physical sales:				
Natural gas	$ 176	$ 630	$ 428	$ 1,106
Oil, condensate and NGL	68	159	114	325
Total physical sales	244	789	542	1,431
Realized and unrealized gains (losses) on financial derivatives(1)	55	(153)	449	(203)
Other revenues	10	19	18	30
Total operating revenues	309	655	1,009	1,258
Operating expenses:				
Cost of products	8	10	13	15
Transportation costs	15	21	35	40
Production costs	54	93	132	184
Depreciation, depletion and amortization	91	197	241	409
General and administrative expenses	51	43	101	90
Ceiling test charges	12	7	2,080	7
Other	2	3	6	6
Total operating expenses	233	374	2,608	751
Operating income (loss)	76	281	(1,599)	507
Other income (expense)(2)	(15)	23	(25)	39
EBIT	$ 61	$ 304	$ (1,624)	$ 546

(1) Includes $99 million and $(46) million for the quarters ended June 30, 2009 and 2008 and $227 million and $(61) million for the six months ended June 30, 2009 and 2008, reclassified from accumulated other comprehensive income associated with accounting hedges.

(2)

Other income (expense) includes equity earnings (losses) from our investment in Four Star.

The table below provides additional detail of our consolidated volumes, prices, and costs per unit as well as volumetric data related to our investment in Four Star. In the table below, we present (i) average realized prices based on physical sales of natural gas and oil, condensate and NGL as well as (ii) average realized prices inclusive of the impacts of financial derivative settlements. Our average realized prices, including financial derivative settlements, reflect cash received and/or paid during the period on settled financial derivatives based on the period the contracted settlements were originally scheduled to occur; however, these prices do not reflect the impact of any associated premiums paid to enter into certain of our derivative contracts.

	Quarters Ended June 30,			Six Months Ended June 30,		
	2009	2008	Percent Variance	2009	2008	Percent Variance
Consolidated volumes, prices and costs per unit:						
Natural gas						
Volumes (MMcf)	55,060	60,270	(9)%	111,922	122,079	(8)%
Average realized price on physical sales ($/Mcf)	$ 3.21	$ 10.46	(69)%	$ 3.82	$ 9.07	(58)%
Average realized price, including financial derivative settlements ($/Mcf) (1)	$ 7.07	$ 9.57	(26)%	$ 7.80	$ 8.57	(9)%
Average transportation costs ($/Mcf)	$ 0.25	$ 0.32	(22)%	$ 0.30	$ 0.30	%
Oil, condensate and NGL						
Volumes (MBbls)	1,483	1,516	(2)%	2,960	3,508	(16)%
Average realized price on physical sales ($/Bbl)	$ 45.54	$ 105.12	(57)%	$ 38.43	$ 92.59	(58)%
Average realized price, including financial derivative settlements ($/Bbl) (1) (2)	$ 75.21	$ 85.38	(12)%	$ 72.68	$ 82.41	(12)%
Average transportation costs ($/Bbl)	$ 0.84	$ 1.07	(21)%	$ 0.88	$ 0.87	1%
Total equivalent volumes						
MMcfe	63,957	69,366	(8)%	129,680	143,128	(9)%
MMcfe/d	703	762	(8)%	717	786	(9)%
Production costs and other cash operating costs ($/Mcfe)						
Average lease operating expenses	$ 0.61	$ 0.79	(23)%	$ 0.75	$ 0.80	(6)%
Average production taxes(3)	0.23	0.54	(57)%	0.26	0.48	(46)%
Total production costs	$ 0.84	$ 1.33	(37)%	$ 1.01	$ 1.28	(21)%
Average general and administrative expenses	0.79	0.63	25%	0.78	0.64	22%
Average taxes, other than production and income taxes	0.05	0.05	%	0.06	0.04	50%
Total cash operating costs	$ 1.68	$ 2.01	(16)%	$ 1.85	$ 1.96	(6)%
Depreciation, depletion and amortization ($/Mcfe)	$ 1.43	$ 2.84	(50)%	$ 1.86	$ 2.85	(35)%
Unconsolidated affiliate volumes (Four Star):						
Natural gas (MMcf)	5,043	4,926		9,903	10,047	
Oil, condensate and NGL (MBbls)	283	249		559	534	
Total equivalent volumes						
MMcfe	6,743	6,419		13,258	13,251	
MMcfe/d	74	71		73	73	

(1) Premiums related to natural gas derivatives settled during the quarter and six months ended June 30, 2008 were $5 million and $10 million. Had we included these premiums in our natural gas average realized price in 2008, our realized price, including financial derivative settlements, would have decreased by $0.09/Mcf for the quarter and six months ended June 30, 2008. We had no premiums related to natural gas derivatives settled during the quarter and six months ended June 30, 2009 or related to oil derivatives settled during the quarters and six months ended June 30, 2009 and 2008.

(2) Amounts for the quarter and six months ended June 30, 2009, include approximately $50 million and $87 million related to the $186 million of cash received in the first quarter of 2009 for the early settlement of oil derivative contracts originally scheduled to mature throughout 2009. We will realize the remaining $99 million in our average realized price over the remainder of the year based on when the settlements were originally scheduled to occur.

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

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Quarter and Six Months Ended June 30, 2009 Compared to Quarter and Six Months Ended June 30, 2008

Our EBIT for the quarter and six months ended June 30, 2009 decreased $0.2 billion and $2.2 billion as compared to the same periods in 2008. The table below shows the significant variances in our financial results for the periods ended June 30, 2009 as compared to the same periods in 2008:

	Quarter Ended June 30, 2009 Variance				Six Months Ended June 30, 2009 Variance			
	Operating Revenue	Operating Expense	Other	EBIT	Operating Revenue	Operating Expense	Other	EBIT
	Favorable/(Unfavorable) (In millions)							
Physical sales								
Natural gas								
Lower realized prices in 2009	$ (400)	$	$	$ (400)	$ (587)	$	$	$ (587)
Lower volumes in 2009	(54)			(54)	(91)			(91)
Oil, condensate and NGL								
Lower realized prices in 2009	(88)			(88)	(160)			(160)
Lower volumes in 2009	(3)			(3)	(51)			(51)
Realized and unrealized gains/(losses) on financial derivatives	208			208	652			652
Other Revenues	(9)			(9)	(12)			(12)
Depreciation, Depletion and Amortization Expense								
Lower depletion rate in 2009		91		91		131		131
Lower production volumes in 2009		15		15		37		37
Production Costs								
Lower lease operating expenses in 2009		15		15		17		17
Lower production taxes in 2009		24		24		35		35
Ceiling Test Charges		(5)		(5)		(2,073)		(2,073)
Earnings from investment in Four Star			(28)	(28)			(48)	(48)
Other		1	(10)	(9)		(4)	(16)	(20)

Total Variances	$ (346)	$ 141	$ (38)	$ (243)	$ (249)	$ (1,857)	$ (64)	$ (2,170)

Physical sales. Physical sales represent accrual-based commodity sales transactions with customers. During the quarter and six months ended June 30, 2009, natural gas, oil, condensate and NGL revenues decreased as compared to the same periods in 2008 due to lower commodity prices and lower production volumes.

Realized and unrealized gains/(losses) on financial derivatives. During the quarter and six months ended June 30, 2009, we recognized gains of $55 million and $449 million compared to losses of $153 million and $203 million during the same periods in 2008 due to lower natural gas and oil prices in 2009 relative to the commodity prices contained in our derivative contracts.

Depreciation, depletion and amortization expense. During 2009, our depreciation, depletion and amortization expense decreased as a result of a lower depletion rate and lower production volumes. The lower depletion rate is primarily a result of the impact of the ceiling test charges recorded in December 2008 and March 2009.

Production costs. Our production costs decreased during 2009 as compared to the same periods in 2008 primarily due to lower production taxes as a result of lower natural gas and oil revenues and lower lease operating expenses from cost declines in the lower commodity price environment.

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Ceiling test charges. We are required to conduct quarterly impairment tests of our capitalized costs in each of our full cost pools. Due to natural gas and oil price levels of $3.63 per MMBtu and $49.66 per barrel as of March 31, 2009, we experienced downward price-related reserve revisions of approximately 400 Bcfe (primarily in our Arklatex, Raton and Mid-Continent areas), and recorded non-cash ceiling test charges of approximately $2.1 billion ($2.0 billion in our domestic full cost pool, $28 million in our Brazilian full cost pool and $9 million in our Egyptian full cost pool related to a dry hole drilled in the South Mariut block).

As of June 30, 2009, spot natural gas and oil prices improved to $3.89 per MMBtu and $69.89 per barrel, resulting in upward price-related revisions of approximately 369 Bcfe during the second quarter of 2009 (primarily in our Rockies, Raton and Arklatex areas). As a result of these higher commodity prices and lower costs, we did not have a ceiling test charge in our domestic or Brazilian full cost pools during the second quarter of 2009. However, we recorded a $12 million charge during the second quarter of 2009 related to a dry hole drilled in the South Mariut block in Egypt. Additionally, during the second quarter of 2008, we recorded a $7 million charge related to a dry hole drilled in the South Feiran block in Egypt.

Other. Our equity earnings from Four Star decreased by $28 million and $48 million during the quarter and six months ended June 30, 2009 as compared to the same periods in 2008 primarily due to lower commodity prices.

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Marketing Segment

Overview. Our Marketing segment s primary focus is to market our Exploration and Production segment s natural gas and oil production, manage El Paso s overall price risk, and manage our remaining legacy contracts that were entered into prior to the deterioration of the energy trading environment in 2002. To the extent it is economical and prudent, we will continue to seek opportunities to reduce the impact of remaining legacy contracts on our future operating results through contract liquidations.

The primary remaining exposure to our operating results relates to changes in the fair value of our legacy PJM power contracts primarily related to changes in power prices at locations within the PJM region. In addition to the PJM power contracts, our legacy contracts include natural gas derivative contracts which are marked-to-market in our operating results as well as transportation-related natural gas and long-term natural gas supply contracts which are accrual-based contracts that impact our revenues as delivery or service under the contracts occurs. All of our remaining contracts are subject to counterparty credit and non-performance risk while each of our mark-to-market contracts is also subject to interest rate exposure. For a further discussion of our remaining contracts, see below and our 2008 Annual Report on Form 10-K.

Operating Results. During the six months ended June 30, 2009, we generated EBIT of $62 million primarily due to mark-to-market gains in the first quarter of 2009 of approximately $52 million related to the application of the provisions of EITF Issue No. 08-5 on our derivative liabilities that have non-cash collateral associated with them, such as letters of credit. For a further description of this standard, see Item 1, Financial Statements, Note 1. Below is further information about our overall operating results during each of the quarters and six months ended June 30:

	Quarters Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(In millions)			
Revenue by Significant Contract Type:				
Production-Related Natural Gas and Oil Derivative Contracts:				
Changes in fair value of options and swaps	$	$ (52)	$	$ (73)
Contracts Related to Legacy Trading Operations:				
Changes in fair value of power contracts	21	(105)	55	(146)
Natural gas transportation-related contracts:				
Demand charges	(8)	(10)	(17)	(19)
Settlements, net of termination payments	5	10	12	24
Changes in fair value of other natural gas derivative contracts	(3)	11	18	11
Total revenues	15	(146)	68	(203)
Operating expenses	(5)	(8)	(6)	(11)
Operating income (loss)	10	(154)	62	(214)
Other income, net		1		1
EBIT	$ 10	$ (153)	$ 62	$ (213)

Production-related Natural Gas and Oil Derivative Contracts. Prior to January 1, 2009, we held production-related natural gas and oil derivative contracts. During the quarter and six months ended June 30, 2008, increases in commodity prices reduced the fair value of these contracts resulting in losses.

Contracts Related to Legacy Trading Operations

Power contracts. Our primary remaining exposure in our power portfolio consists of changes in locational power price differences in the PJM region, changes in counterparty credit risk, and changes in interest rates. Prior to agreements entered into through 2008, we were also exposed to changes in installed capacity prices and commodity prices. Power prices in the PJM region are highly volatile due to changes in fuel prices and transmission congestion at certain locations in the region, and future changes in locational prices could continue to significantly impact the fair value of our power contracts.

During the quarter and six months ended June 30, 2009, we recognized mark-to-market gains of $21 million and $55 million on these contracts which includes a $33 million gain recorded in the first quarter related to the application of EITF Issue No. 08-5 on certain of our derivative liabilities. During the quarter and six months ended June 30, 2008, we recognized mark-to-market losses of $105 million and $146 million primarily resulting from changes in locational PJM power prices and interest rates. Also impacting our results for the six months ended June 30, 2008, was a capacity purchase agreement executed during the first quarter of 2008 with a counterparty to economically hedge our remaining capacity exposure.

Natural gas transportation-related contracts. As of June 30, 2009, our transportation contracts provide us with approximately 0.6 Bcf/d of pipeline capacity. For the remainder of 2009, we anticipate demand charges related to this capacity of approximately $21 million, which we expect will average $22 million annually from 2010 through 2013. 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. 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 and counterparty credit risk used to value these contracts. The mark-to-market gain of $18 million recognized for the six months ended June 30, 2009 includes a $19 million gain in the first quarter of 2009 related to the application of EITF Issue No. 08-5 on certain of our derivative liabilities.

Power Segment

Overview. As of June 30, 2009, our remaining investment, guarantees and letters of credit related to projects in this segment totaled approximately $184 million which consisted of approximately $168 million in equity investments and notes and accounts receivable and approximately $16 million in financial guarantees and letters of credit, as follows (in millions):

Area	
South America	
Manaus & Rio Negro	$ 46
Bolivia-to-Brazil Pipeline	126
Asia	12
Total	$ 184

During the first quarter of 2008, we transferred the ownership of our Manaus and Rio Negro power plants in Brazil to the plants   power purchaser. While we no longer own the Manaus and Rio Negro power plants, we still have exposure relating to outstanding receivables due from the power purchaser. In the first quarter of 2009, we completed the sale of our investment in Porto Velho to our partner in the project for total consideration of $179 million, including $78 million in notes receivable. Subsequently, in the second quarter of 2009, we sold the notes, including accrued interest, to a third party financial institution for $57 million and recorded a loss of $22 million. In the second quarter of 2009, we also sold our investment in the Argentina-to-Chile pipeline to our partners for approximately $32 million. Until the sale of our remaining international investments is completed, related receivables are collected or matters further discussed in Item 1, Financial Statements, Note 13 are resolved, any changes in regional political and economic conditions could negatively impact the anticipated proceeds we may receive, which could result in impairments of our remaining assets and investments.

Operating Results. For the quarter and six months ended June 30, 2009, our Power segment generated EBIT losses of $21 million and $17 million compared to EBIT of $12 million and $10 million during the same periods in 2008. Our 2009 EBIT losses primarily relate to the sale of the Porto Velho notes receivable during the second quarter of

2009. Our EBIT in both periods in 2008 was primarily due to gains recognized on the sale of investments in Asia and Central America. For a discussion of developments and other matters that could impact our remaining assets and investments, see Item 1, Financial Statements, Note 13.

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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 year results. The following is a summary of significant items impacting the EBIT in our corporate activities for the periods ended June 30:

	Quarters Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(In millions)			
Change in litigation, insurance and other reserves	26	46	23	57
Foreign currency fluctuations on Euro-denominated debt	2		2	(6)
Gain on disposition of a portion of our telecommunications business				18
Other	3	(5)	(1)	11
Total EBIT	$ 31	$ 41	$ 24	$ 80

Litigation, Insurance, and Other Reserves. During the quarter and six months ended June 30, 2009, we recorded mark-to-market gains of $25 million associated with an indemnification in conjunction with the sale of a legacy ammonia facility based on decreases in ammonia prices during the second quarter. In the first six months of 2008, we recorded a net favorable adjustment related to resolving certain legacy litigation matters including settlement of our Case Corporation indemnification dispute for $65 million in the first quarter of 2008, among other items (See Item 1, Financial Statements, Note 9). Partially offsetting these 2008 settlements were approximately $34 million in mark-to-market losses based on significant increases in ammonia prices during the first quarter of 2008. Further changes in ammonia prices may continue to impact this contract, which could impact our results in the future.

We also have a number of pending litigation matters and reserves related to our historical business operations that also affect our corporate results. Adverse rulings or unfavorable outcomes or settlements against us related to these matters have impacted and may continue to impact our future results.

Interest and Debt Expense

Our interest and debt expense was higher in 2009 compared with 2008 primarily due to higher average debt balances in 2009 when compared to 2008.

Income Taxes

	Quarters Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(In millions, except for rates)			
Income tax expense (benefit)	$66	$87	$(460)	$235
Effective tax rate	40%	31%	35%	36%

For a discussion of our effective tax rates and other matters impacting our income taxes, see Item 1, Financial Statements, Note 4.

Commitments and Contingencies

For a further discussion of our commitments and contingencies, see Item I, Financial Statements, Note 9, which is incorporated herein by reference.

Climate Change and Energy Legislation. There are various legislative and regulatory measures relating to climate change and energy policies that have been proposed that, if enacted, will likely impact our business.

Climate Change Regulation. Measures to address climate change and greenhouse gas (GHG) emissions are in various phases of discussions or implementation at international, federal, regional and state levels. These measures include the Kyoto Protocol, which has been ratified by some of the international countries in which we have operations such as Mexico, Brazil, and Egypt. It is likely that federal legislation requiring GHG controls will be enacted in the next few years in the United States. Although it is uncertain what legislation will ultimately be enacted, it is our belief that cap-and-trade or other legislation that sets a price on carbon emissions will increase demand for natural gas, particularly in the power sector. We believe this increased demand will occur due to substantially less carbon emissions associated with the use of natural gas compared with alternate fuel sources for power generation, including coal and oil-fired power generation. However, the actual impact on demand will depend on the legislative provisions that are ultimately adopted, including the level of emission caps, allowances granted and the cost of emission credits.

It is also likely that any federal legislation enacted would increase our cost of environmental compliance by requiring us to install additional equipment to reduce carbon emissions from our larger facilities as well as to potentially purchase emission credits. Based on 2007 data we reported to the California Climate Action Registry (CCAR), our operations in the United States emitted approximately 13.9 million tonnes of carbon dioxide equivalent emissions in 2007. We believe that approximately 12.4 million tonnes of the GHG emissions that we reported to CCAR would be subject to regulations under the climate change legislation that passed in the U.S. House of Representatives in July 2009, with over one-third of this amount being subject to the cap-and-trade rules contained in the proposed legislation and the remainder being subject to performance standards. As proposed, the portion of our GHG emissions that would be subject to performance standards could require us to install additional equipment or initiate new work practice standards to reduce emission levels at many of our facilities, the costs of which would likely be material. Although we believe that many of these costs should be recoverable in our sales price for natural gas and the rates charged by our pipelines, recovery through these mechanisms is still uncertain at this time.

The Environmental Protection Agency (EPA) is also considering new regulations to regulate GHGs under the Clean Air Act, as well as to monitor and report GHG emissions on an annual basis. In addition, various lawsuits have been filed seeking to force further regulation of GHG emissions, as well as to require specific companies to reduce GHG emissions from their operations. Enactment of additional regulations, as well as lawsuits, could have an impact on our ability to obtain permits and other regulatory approvals with regard to existing and new facilities, could impact our costs of operations, as well as require us to install new equipment to control emissions from our facilities.

Energy Legislation. In conjunction with these climate change proposals, there have been various federal and state legislative and regulatory proposals that would create additional incentives to move to a less carbon intensive footprint . These proposals would establish renewable portfolio standards at both the federal and state level, some of which would require a material increase of renewable sources, such as wind and solar power generation, over the next several decades. Additionally, the proposals would establish incentives for energy efficiency and conservation. Although the ultimate targets that would be established in these areas are uncertain at this time, such proposals if enacted could negatively impact natural gas usage over the longer term.

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Liquidity and Capital Resources

Over the past several years, our focus has been on expanding our core pipeline and exploration and production businesses to provide for long-term growth and value. During this period, we continued to strengthen our balance sheet primarily through managing our overall debt obligations. Our primary sources of cash are cash flow from operations and amounts available to us under our revolving credit facilities. As conditions warrant, we may also generate funds through capital market activities and 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 debt when conditions warrant. In the first six months of 2009, we continued to generate significant positive operating cash flows from both our core pipeline and production operations which we expect to continue for the remainder of 2009.

In response to the significant volatility and instability in the global financial markets that began in 2008, we have taken several actions to address our liquidity needs including a reduction in our capital program for 2009, selling certain non-core assets (as further discussed below), issuing debt to fund our May 2009 debt maturities and fund our 2009 capital program, and executing a binding agreement with GIP whereby they will invest up to $700 million in our Ruby pipeline project as further discussed in *Overview and Outlook* above. Discussed below are (i) our available liquidity and liquidity outlook for the remainder of 2009 as well as (ii) an overview of cash flow activities for the first six months of 2009.

Available Liquidity and Liquidity Outlook for 2009. At June 30, 2009, we had approximately $2.3 billion of available liquidity, consisting of $0.8 billion of cash (exclusive of $140 million of cash at EPB) and approximately $1.5 billion of capacity available to us under our various credit facilities (exclusive of $215 million available to EPB under its revolving credit facility.) Traditionally, we have pursued additional bank financings, project financings or debt capital markets transactions to supplement our available cash and credit facilities which we have used to fund the capital expenditure programs of our core businesses, meet operating needs and repay debt maturities.

Our cash capital expenditures for the six months ended June 30, 2009, and the amount of cash we expect to spend for the remainder of 2009 to grow and maintain our businesses are as follows:

	Six Months Ended June 30, 2009	2009 Remaining	Total
		(In billions)	
Pipelines			
Maintenance	$ 0.2	$ 0.2	$ 0.4
Growth(1)	0.6	1.1	1.7
Exploration and Production	0.6	0.4	1.0
Other		0.1	0.1
	$ 1.4	$ 1.8	$ 3.2

(1) Our pipeline growth capital expenditures reflect 100 percent of the capital related to the Ruby pipeline project.

Through July 2009, as part of our efforts to meet our projected liquidity needs, which include our 2009 capital program, we have successfully generated additional liquidity of approximately $2.6 billion since November 2008. Of this amount, we (i) generated $1.2 billion in proceeds through public debt offerings (approximately $1 billion of El

Paso notes and $250 million of TGP notes), (ii) obtained a 364-day $300 million secured revolving credit facility collateralized by certain proved oil and gas reserves of a production subsidiary, (iii) entered into three additional facilities for a combined $250 million in letter of credit capacity, (iv) completed $300 million of financings through our subsidiaries related to our Elba Island LNG facility and Elba Express pipeline project, (v) generated $215 million in conjunction with contributing additional interests in Colorado Interstate Gas Company, our pipeline subsidiary, to our master limited partnership and (vi) completed the sale of approximately $300 million of non-core assets (primarily in our Exploration and Production and Power segments).

We believe our actions taken over the last several months provide sufficient liquidity to meet our operating needs and fund our 2009 capital program. When prudent we will continue to be opportunistic in building liquidity to meet our long-term capital needs; however, there are no assurances that we will be able to access the financial markets to fund our long-term capital needs. To the extent the financial markets are restricted, there is a further decline in commodity prices from current levels, or any of our announced actions are not sufficient, it is possible that additional adjustments to our plan and outlook will be required which could impact our financial and operating performance. These alternatives or adjustments to our plan could include additional reductions in our discretionary capital program, further reductions in operating and general and administrative expenses, secured financing arrangements, seeking additional partners for other growth projects and the sale of additional non-core assets which could impact our financial and operating performance.

Additional Factors That Could Impact Our Future Liquidity. Listed below are two additional factors that could impact our liquidity.

Price Risk Management Activities and Margining Requirements. We currently post letters of credit for the required margin on certain derivative contracts in our Marketing segment. Depending on changes in commodity prices or interest rates, we could be required to post additional margin or may recover margin earlier than anticipated. A 10 percent change in natural gas and power prices would not have had a significant impact on the margin requirements of our derivative contracts as of June 30, 2009. Additionally, we are exposed to (and have adjusted the fair value of these contracts for) the risk that the counterparties to our derivative contracts may not be able to perform or post the necessary collateral with us. We have assessed this counterparty credit and non-performance risk given the recent instability in the credit markets and determined that our exposure is primarily limited to five financial institutions, each of which has a current Standard & Poor s credit rating of A or better.

Hurricanes Ike and Gustav. During 2008, our pipeline and exploration and production facilities were damaged by Hurricanes Ike and Gustav. We assessed the damages resulting from these hurricanes and the corresponding impact on estimated costs to repair and abandon impacted facilities. Although our estimates may change in the future, we expect the majority of our planned costs to be pipeline related. Our current planned pipeline expenditures are approximately $157 million, a majority of which are capital expenditures that we expect will be spent in 2009 and 2010. None of this amount is recoverable from insurance due to the losses not exceeding our self-retention levels for these events.

Overview of Cash Flow Activities. During the first six months of 2009, we generated positive operating cash flow of approximately $1.2 billion primarily as a result of cash provided by our pipeline and exploration and production operations. In addition, we generated $0.3 billion in proceeds from the sale of our interests in the Porto Velho power generation facility in Brazil, the sale of our investment in the Argentina-to-Chile pipeline and the sale of non-core natural gas producing properties. We also generated $1.2 billion in proceeds primarily due to the issuance of $0.7 billion of unsecured notes, completing financings of $0.2 billion for our Elba LNG facility and Elba Express pipeline project, and issuing additional units in our master limited partnership generating $0.2 billion in cash proceeds. We utilized a portion of these amounts to fund maintenance and growth projects in our pipeline and exploration and production operations, repay our May 2009 debt maturities of $0.9 billion, and pay dividends, among other items. For the six months ended June 30, 2009, our cash flows from continuing operations are summarized as follows:

		2009
		(In billions)
Cash Flow from Operations		
Operating activities		
Net loss	$	(0.9)
Ceiling test charges		2.1
Total cash flow from operations	$	1.2
Other Cash Inflows		
Investing activities		
Net proceeds from the sale of assets and investments	$	0.3
Financing activities		
Net proceeds from the issuance of long-term debt		1.0
Net proceeds from issuance of noncontrolling interests		0.2
		1.2

Total other cash inflows	$	1.5
Cash Outflows		
Investing activities		
Capital expenditures	$	1.4
Financing activities		
Payments to retire long-term debt and other financing obligations		1.2
Dividends and other		0.2
		1.4
Total cash outflows	$	2.8
Net change in cash	$	(0.1)

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Contractual Obligations

The following information provides updates to our contractual obligations and should be read in conjunction with the information disclosed in our 2008 Annual Report on Form 10-K.

Commodity-Based Derivative Contracts

We use derivative financial instruments in our Exploration and Production and Marketing segments to manage the price risk of commodities. Our commodity-based derivative contracts are not currently designated as accounting hedges and include options, swaps and other natural gas and power purchase and supply contracts that are not traded on active exchanges. The following table details the fair value of our commodity-based derivative contracts by year of maturity as of June 30, 2009:

	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity 6 to 10 Years	Total Fair Value
			(In millions)		
Assets	$ 459	$ 140	$ 15	$ 13	$ 627
Liabilities	(179)	(341)	(137)	(89)	(746)
Total commodity-based derivatives	$ 280	$ (201)	$ (122)	$ (76)	$ (119)

The following is a reconciliation of our commodity-based derivatives for the six months ended June 30, 2009:

	Commodity-Based Derivatives (In millions)
Fair value of contracts outstanding at January 1, 2009	$ (25)
Fair value of contract settlements during the period[1]	(562)
Changes in fair value of contracts during the period	295
Premiums paid during the period	173
Net changes in contracts outstanding during the period	(94)
Fair value of contracts outstanding at June 30, 2009	$ (119)

(1) Includes amounts received related to the early settlement of production-related oil derivative contracts prior to their scheduled maturity.

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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 2008 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 2008 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 contracts 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 the remaining forecasted natural gas and oil production.

Other Commodity-Based Derivatives. In our Marketing segment, we have long-term natural gas and power derivative contracts which include forwards, swaps, options and futures that we either intend to manage until their expiration or seek opportunities to liquidate to the extent it is economical and prudent. We utilize a sensitivity analysis to manage the commodity price risk associated with our other commodity-based derivative contracts.

Sensitivity Analysis. The table below presents the hypothetical sensitivity of our production-related derivatives and our other commodity-based derivatives to changes in fair values arising from immediate selected potential changes in the market prices (primarily natural gas, oil and power prices and basis differentials) used to value these contracts. This table reflects the sensitivities of the derivative contracts only and does not include any underlying hedged commodities.

		Change in Market Price			
		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
			(In millions)		
Production-related derivatives net assets					
June 30, 2009	$ 433	$ 262	$(171)	$ 608	$175
December 31, 2008	$ 682	$ 582	$(100)	$ 785	$103
Other commodity-based derivatives net liabilities					
June 30, 2009	$(552)	$(560)	$ (8)	$(543)	$ 9
December 31, 2008	$(707)	$(719)	$ (12)	$(695)	$ 12

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Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of June 30, 2009, 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. 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. Our disclosure controls and procedures are designed to provide reasonable assurance of achieving their objectives and our CEO and CFO have concluded that our disclosure controls and procedures are effective at a reasonable level of assurance at June 30, 2009.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the second quarter of 2009 that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

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PART II OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Financial Statements, Note 9, which is incorporated herein by reference. Additional information about our legal proceedings can be found in Part I, Item 3 of our 2008 Annual Report on Form 10-K filed with the SEC.

Latigo Natural Gas Storage. In April 2009, the Colorado Department of Public Health and Environment (CDPHE) issued a Compliance Advisory alleging various violations related to the operation of an evaporation pond at the Latigo underground natural gas storage field including failure to account for, and adequately permit, methanol emissions. CIG met with the CDPHE to discuss the Compliance Advisory and address their concerns. The pond has been included in the permit as an emissions source. CIG is also required to perform a Reasonable Available Control Technology analysis to determine if other emissions control measures are required, which is now in progress.

Natural Buttes. In May 2004, the EPA issued a Compliance Order to CIG related to alleged violations of a Title V air permit in effect at CIG s Natural Buttes Compressor Station. In September 2005, the matter was referred to the U.S. Department of Justice (DOJ). CIG entered into a tolling agreement with the United States and conducted settlement discussions with the DOJ and the EPA. While conducting some testing at the facility, CIG discovered that three generators installed in 1992 may have been emitting oxides of nitrogen at levels which suggested the facility should have obtained a Prevention of Significant Deterioration (PSD) permit when the generators were first installed, and CIG promptly reported those test data to the EPA. We have executed a Consent Decree with the DOJ under which we have agreed to pay a total of $1.02 million to settle all of these Title V and PSD issues at the Natural Buttes Compressor Station, and in addition, we will conduct ambient air monitoring at the Uintah Basin for a period of two years. The Consent Decree has been lodged with United States District Court for the District of Utah, Central Division. The public will have thirty days to comment on the Consent Decree after which time the Court will consider final entry of the Consent Decree.

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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 2008 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.

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

Proposals presented for a stockholders vote at our Annual Meeting of Stockholders held on May 6, 2009, included the election of eleven directors; the approval of the El Paso Corporation 2005 Omnibus Incentive Compensation Plan, as amended and restated, to increase the number of shares available for issuance by 12.5 million; the approval of the El Paso Corporation Employee Stock Purchase Plan, as amended and restated, to extend the term of the plan until such time as no additional shares remain available for purchase; and the ratification of the appointment of Ernst & Young LLP as our independent registered public accounting firm for the fiscal year ending December 31, 2009.

Proposal 1

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

Nominee	For	Against	Abstain
Juan Carlos Braniff	587,503,213	12,208,228	1,826,729
James L. Dunlap	590,398,636	9,296,720	1,842,814
Douglas L. Foshee	586,381,261	13,343,649	1,813,260
Robert W. Goldman	580,723,930	18,943,849	1,870,391
Anthony W. Hall Jr.	590,163,199	9,410,986	1,963,986
Thomas R. Hix	590,895,950	8,768,819	1,873,400
Ferrell P. McClean	590,527,139	9,156,064	1,854,968
Steven J. Shapiro	590,229,848	9,457,720	1,850,602
J. Michael Talbert	590,577,728	9,059,536	1,900,907
Robert F. Vagt	481,688,729	117,923,943	1,925,498
John L. Whitmire	590,713,660	8,862,740	1,961,770

Proposal 2

The El Paso Corporation 2005 Omnibus Incentive Compensation Plan, as amended and restated, was approved with the following voting results:

	For	Against	Abstain	Broker Non-Vote
Proposal to approve the El Paso Corporation 2005 Omnibus Incentive Compensation Plan, as amended and restated, to increase the number of shares available for issuance by 12.5 million	464,384,350	21,053,449	1,879,815	114,226,711

Proposal 3

The El Paso Corporation Employee Stock Purchase Plan, as amended and restated, was approved with the following voting results:

	For	Against	Abstain	Broker Non-Vote
Proposal to approve the El Paso Corporation Employee Stock Purchase Plan, as amended and restated, to extend the term of the plan until such time as no additional shares remain available for purchase	478,950,720	6,796,611	1,570,885	114,226,109

Proposal 4

The appointment of Ernst & Young LLP as El Paso s independent registered public accounting firm for the fiscal year 2009 was ratified with the following voting results:

For	Against	Abstain

Proposal to ratify the appointment of Ernst & Young LLP as our independent registered public accounting firm for the fiscal year ending December 31, 2009	595,341,727	4,360,647	1,841,951

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Item 5. Other Information

None.

Item 6. Exhibits

The Exhibit Index is incorporated herein by reference.

The agreements included as exhibits to this report are intended to provide information regarding their terms and not to provide any other factual or disclosure information about us or the other parties to the agreements. The agreements may contain representations and warranties by the parties to the agreements, including us, solely for the benefit of the other parties to the applicable agreement and:

- should not in all instances be treated as categorical statements of fact, but rather as a way of allocating the risk to one of the parties if those statements prove to be inaccurate;

- may have been qualified by disclosures that were made to the other party in connection with the negotiation of the applicable agreement, which disclosures are not necessarily reflected in the agreement;

- may apply standards of materiality in a way that is different from what may be viewed as material to certain investors; and

- were made only as of the date of the applicable agreement or such other date or dates as may be specified in the agreement and are subject to more recent developments.

Accordingly, these representations and warranties may not describe the actual state of affairs as of the date they were made or at any other time.

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SIGNATURES

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

EL PASO CORPORATION

Date: August 7, 2009

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

Date: August 7, 2009

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

EL PASO CORPORATION
EXHIBIT INDEX

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

Exhibit Number	Description
10	El Paso Corporation 2005 Omnibus Incentive Compensation Plan, as amended and restated effective May 6, 2009 (incorporated by reference to Exhibit 10.A to our Form 8-K filed with the SEC on May 6, 2009).
*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.
*101	Interactive Data File.