EL PASO CORP/DE
Form 10-Q
November 09, 2009

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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 September 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 November 3, 2009: 701,270,947

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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 September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Operating revenues	$ 981	$ 1,598	$ 3,438	$ 4,020
Operating expenses				
Cost of products and services	45	68	158	195
Operation and maintenance	346	328	910	874
Ceiling test charges	5	1	2,085	8
Depreciation, depletion and amortization	200	292	653	903
Taxes, other than income taxes	56	70	181	230
	652	759	3,987	2,210
Operating income (loss)	329	839	(549)	1,810
Earnings from unconsolidated affiliates	11	52	42	141
Other income, net	33	(3)	71	52
Interest and debt expense	(256)	(221)	(764)	(675)
Income (loss) before income taxes	117	667	(1,200)	1,328
Income tax expense (benefit)	35	215	(425)	450
Net income (loss)	82	452	(775)	878
Net income attributable to noncontrolling interests	(15)	(7)	(38)	(23)
Net income (loss) attributable to El Paso Corporation	67	445	(813)	855
Preferred stock dividends	9	9	28	28
Net income (loss) attributable to El Paso Corporation s common stockholders	$ 58	$ 436	$ (841)	$ 827
Basic earnings per common share				
Net income (loss) attributable to El Paso Corporation s common stockholders	$ 0.08	$ 0.63	$ (1.21)	$ 1.19
Diluted earnings per common share				
Net income (loss) attributable to El Paso Corporation s common stockholders	$ 0.08	$ 0.58	$ (1.21)	$ 1.12

Dividends declared per El Paso Corporation s common share	$ 0.05	$ 0.05	$ 0.15	$ 0.13

See accompanying notes.

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

	September 30, 2009	December 31, 2008
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,121	$ 1,024
Accounts and notes receivable		
Customers, net of allowance of $9 in 2009 and 2008	271	466
Affiliates	84	133
Other	121	217
Materials and supplies	172	187
Assets from price risk management activities	316	876
Deferred income taxes	231	
Other	109	148
Total current assets	2,425	3,051
Property, plant and equipment, at cost		
Pipelines	19,237	18,042
Natural gas and oil properties, at full cost	20,537	20,009
Other	357	342
	40,131	38,393
Less accumulated depreciation, depletion and amortization	22,931	20,535
Total property, plant and equipment, net	17,200	17,858
Other assets		
Investments in unconsolidated affiliates	1,705	1,703
Assets from price risk management activities	109	201
Other	718	855
	2,532	2,759
Total assets	$ 22,157	$ 23,668

See accompanying notes.

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

	September 30, 2009	December 31, 2008
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 300	$ 372
Affiliates	7	6
Other	492	618
Short-term financing obligations, including current maturities	339	1,090
Liabilities from price risk management activities	224	250
Accrued interest	241	192
Other	852	715
Total current liabilities	2,455	3,243
Long-term financing obligations, less current maturities	13,633	12,818
Other		
Liabilities from price risk management activities	523	767
Deferred income taxes	265	565
Other	1,557	1,679
	2,345	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 715,877,755 shares in 2009 and 712,628,781 shares in 2008	2,148	2,138
Additional paid-in capital	4,505	4,612
Accumulated deficit	(3,466)	(2,653)
Accumulated other comprehensive loss	(709)	(532)
Treasury stock (at cost); 14,612,967 shares in 2009 and 14,061,474 shares in 2008	(282)	(280)
Total El Paso Corporation stockholders equity	2,946	4,035
Noncontrolling interests	778	561

Total equity		3,724		4,596
Total liabilities and equity	$	22,157	$	23,668

See accompanying notes.

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

	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Cash flows from operating activities		
Net income (loss)	$ (775)	$ 878
Adjustments to reconcile net income (loss) to net cash from operating activities		
Depreciation, depletion and amortization	653	903
Ceiling test charges	2,085	8
Deferred income tax expense (benefit)	(448)	470
Earnings from unconsolidated affiliates, adjusted for cash distributions	17	(12)
Other non-cash income items	53	16
Asset and liability changes	196	(212)
Net cash provided by operating activities	1,781	2,051
Cash flows from investing activities		
Capital expenditures	(2,081)	(1,905)
Cash paid for acquisitions, net of cash acquired	(39)	(362)
Net proceeds from the sale of assets and investments	303	671
Net change in restricted cash	41	35
Other	(26)	44
Net cash used in investing activities	(1,802)	(1,517)
Cash flows from financing activities		
Net proceeds from issuance of long-term debt	1,369	4,083
Payments to retire long-term debt and other financing obligations	(1,290)	(3,556)
Dividends paid	(133)	(113)
Net proceeds from issuance of noncontrolling interests	212	15
Distributions to noncontrolling interest holders	(33)	(20)
Repurchase of common shares		(77)
Other	(7)	9
Net cash provided by financing activities	118	341
Change in cash and cash equivalents	97	875
Cash and cash equivalents		
Beginning of period	1,024	285
End of period	$ 1,121	$ 1,160

See accompanying notes.

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

	Nine Months Ended September 30, 2009	Nine Months Ended September 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	10	8
Balance at end of period	2,148	2,136
Additional paid-in capital:		
Balance at beginning of period	4,612	4,699
Dividends	(133)	(119)
Other, including stock-based compensation	26	69
Balance at end of period	4,505	4,649
Accumulated deficit:		
Balance at beginning of period	(2,653)	(1,834)
Net income (loss) attributable to El Paso Corporation	(813)	855
Cumulative effect of adopting new pension plan accounting standards, net of income tax of $2		4
Balance at end of period	(3,466)	(975)
Accumulated other comprehensive loss:		
Balance at beginning of period	(532)	(272)
Other comprehensive income (loss)	(177)	102
Cumulative effect of adopting new pension plan accounting standards, net of income tax of $2		3
Balance at end of period	(709)	(167)
Treasury stock, at cost:		
Balance at beginning of period	(280)	(191)
Share repurchases		(77)
Stock-based and other compensation	(2)	(10)
Balance at end of period	(282)	(278)
Total El Paso Corporation stockholders equity at end of period	2,946	6,115

Noncontrolling interests:		
Balance at beginning of period	561	565
Distributions paid to noncontrolling interests	(33)	(20)
Issuance of noncontrolling interests	212	15
Net income attributable to noncontrolling interests	38	23
Other		(24)
Balance at end of period	778	559
Total equity at end of period	$ 3,724	$ 6,674

See accompanying notes.

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

	Quarters Ended September 30, 2009	Quarters Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Net income (loss)	$ 82	$ 452	$ (775)	$ 878
Pension and postretirement obligations:				
Unrealized actuarial losses arising during period (net of income taxes of $1 in 2008)				(2)
Reclassification of actuarial losses during period (net of income taxes of $3 and $11 in 2009 and $2 and $7 in 2008)	7	3	21	13
Cash flow hedging activities:				
Unrealized mark-to-market gains (losses) arising during period (net of income taxes of $5 and $3 in 2009 and $227 and $5 in 2008)	(5)	405	5	10
Reclassification adjustments for changes in initial value to the settlement date (net of income taxes of $34 and $114 in 2009 and $24 and $46 in 2008)	(61)	42	(203)	81
Other comprehensive income (loss)	(59)	450	(177)	102
Comprehensive income (loss)	23	902	(952)	980
Comprehensive income attributable to noncontrolling interests	(15)	(7)	(38)	(23)
Comprehensive income (loss) attributable to El Paso Corporation	$ 8	$ 895	$ (990)	$ 957

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 (GAAP). 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 September 30, 2009, and for the quarters and nine months ended September 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 January 1, 2009 adoption of new presentation and disclosure requirements for noncontrolling interests. Our financial statements for prior periods also include certain reclassifications that were made to conform to the current period presentation, none of which impacted our reported net income (loss) or stockholders equity. 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 November 6, 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 new accounting and reporting standards related to 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 also adopted accounting standard updates regarding how companies 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 the derivative liabilities in our Marketing segment are supported by letters of credit. Under these accounting standard updates, 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 these new accounting updates.

Business Combinations. On January 1, 2009, we adopted accounting standard updates related to business acquisitions. These updates apply to acquisitions that are effective after December 31, 2008 and 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.

Noncontrolling Interests. Effective January 1, 2009, we adopted accounting standard updates on accounting and reporting for noncontrolling interests in the financial statements which require us to present our noncontrolling interests that have the characteristics of permanent equity (primarily related 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 on our balance sheets. Additionally, we are also required 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 these changes to the presentation and disclosure requirements related to noncontrolling interests. These accounting standard updates also require 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 September 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 updates to the existing accounting standards on financial asset transfers. Among other items, these accounting standard updates eliminate the concept of a qualifying special-purpose entity (QSPE) for purposes of evaluating whether an entity should be consolidated as a variable interest entity and are 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 these accounting standard updates 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 updates to existing accounting standards for variable interest entities which revise how companies determine their primary beneficiaries, among other changes. These updates require companies to use a qualitative approach based on their responsibilities and controlling power over the variable interest entities operations rather than a quantitative approach in determining the primary beneficiary as previously required. We are currently assessing the impact that these accounting standard updates, effective January 1, 2010, 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 $49 million as of September 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. During the third quarter of 2009, we acquired a 50 percent interest in the South Alamein concession in the Western Desert of Egypt for approximately $39 million. During the nine months ended September 30, 2008, we acquired additional interests in onshore domestic natural gas and oil properties for approximately $61 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 14). 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. During 2009 we also sold 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.

3. Ceiling Test Charges

During the nine months ended September 30, 2009, we recorded a reduction to our property, plant and equipment due to total non-cash ceiling test charges of $2.1 billion that resulted primarily from declines in natural gas prices. In the first quarter of 2009, capitalized costs exceeded the ceiling limit by approximately $2.0 billion for our domestic full cost pool and approximately $28 million for our Brazilian full cost pool. The calculation of the first quarter of 2009 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.

By September 30, 2009, spot natural gas prices declined to $3.30 per MMBtu while oil prices improved to $70.61 per barrel. As a result of higher oil prices, reserve additions and lower costs, we did not have a ceiling test charge in our domestic or Brazilian full cost pools during the second or third quarters of 2009.

During the nine months ended September 30, 2009, we recorded non-cash ceiling test charges in our Egyptian full cost pool totaling approximately $26 million, of which $5 million was recorded in the third quarter of 2009. During the quarter and nine months ended September 30, 2008, we recorded non-cash ceiling test charges of $1 million and $8 million 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. We may be required to record additional ceiling test charges in the future if commodity prices decrease from the September 30, 2009 levels.

4. Income Taxes

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

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(In millions, except rates)			
Income tax (benefit) expense	$ 35	$ 215	$ (425)	$ 450
Effective tax rate	30%	32%	35%	34%

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 our annual estimate of 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 nine months ended September 30, 2009 and 2008, 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 third quarter of 2009, our effective tax rate was primarily impacted by foreign income which can be taxed at different rates. During the third quarter of 2008, our effective tax rate was lower than the statutory rate primarily due to the foreign tax impact of fluctuations in exchange rates.

Deferred Tax Asset. As of September 30, 2009, we have a net federal deferred tax asset of $131 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 September 30,

	2009		2008	
	Basic	**Diluted**	**Basic**	**Diluted**
	(In millions, except per share amounts)			
Net income attributable to El Paso Corporation	$ 67	$ 67	$ 445	$ 445
Convertible preferred stock dividends	(9)	(9)	(9)	
Interest on trust preferred securities				3
Net income attributable to El Paso Corporation s common stockholders	$ 58	$ 58	$ 436	$ 448
Weighted average common shares outstanding	696	696	696	696
Effect of dilutive securities:				
Options and restricted stock		4		4
Trust preferred securities				8
Convertible preferred stock				58
Weighted average common shares outstanding and dilutive securities	696	700	696	766
Basic and diluted earnings per common share:				
Net income attributable to El Paso Corporation s common stockholders	$ 0.08	$ 0.08	$ 0.63	$ 0.58

Nine Months Ended September 30,

	2009		2008	
	Basic	**Diluted**	**Basic**	**Diluted**
	(In millions, except per share amounts)			
Net income (loss) attributable to El Paso Corporation	$ (813)	$ (813)	$ 855	$ 855
Convertible preferred stock dividends	(28)	(28)	(28)	
Interest on trust preferred securities				8
Net income (loss) attributable to El Paso Corporation s common stockholders	$ (841)	$ (841)	$ 827	$ 863
Weighted average common shares outstanding	695	695	697	697
Effect of dilutive securities:				
Options and restricted stock				4
Trust preferred securities				8
Convertible preferred stock				58
Weighted average common shares outstanding and dilutive securities	695	695	697	767

Basic and diluted earnings per common share:				
Net income (loss) attributable to El Paso Corporation s common stockholders	$ (1.21)	$ (1.21)	$ 1.19	$ 1.12

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 nine months ended September 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 quarter ended September 30, 2009, our convertible preferred stock and trust preferred securities were antidilutive. Additionally, for the quarters ended September 30, 2009 and 2008 and nine months ended September 30, 2008, certain of our employee stock options were antidilutive. For a further discussion of our potentially dilutive securities, see our 2008 Annual Report on Form 10-K.

6. Fair Value Measurements

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 interest rate swaps, 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 September 30, 2009 (in millions):

	Level 1	Level 2	Level 3	Total
Assets				
Commodity-based derivatives				
Production-related natural gas and oil derivatives	$	$ 273	$	$ 273
Other natural gas derivatives		79	20	99
Power-related derivatives			42	42
Interest rate derivatives		11		11
Marketable securities invested in non-qualified compensation plans	19			19
Total assets	19	363	62	444
Liabilities				
Commodity-based derivatives				
Production-related natural gas and oil derivatives		(54)		(54)
Other natural gas derivatives		(136)	(143)	(279)
Power-related derivatives			(396)	(396)
Interest rate derivatives		(18)		(18)
Other			(32)	(32)
Total liabilities		(208)	(571)	(779)
Total	$ 19	$ 155	$ (509)	$ (335)

On certain derivative contracts recorded as assets we are exposed to the risk that our counterparties may not 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. Based on this assessment, we have determined that our exposure is primarily related to our production-related derivatives 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 nine months ended September 30, 2009 (in millions):

	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
Quarter Ended September 30, 2009					
Assets	$ 73	$ (10)	$	$ (1)	$ 62
Liabilities	(582)	(9)	(3)	23	(571)
Total	$ (509)	$ (19)	$ (3)	$ 22	$ (509)

Nine Months Ended September 30, 2009					
Assets	$ 103	$ (35)	$	$ (6)	$ 62
Liabilities	(751)	79	22	79	(571)
Total	$ (648)	$ 44	$ 22	$ 73	$ (509)

(1) Includes approximately $19 million of net losses and $30 million of net gains that had not been realized through settlements for the quarter and nine months ended September 30, 2009.

(2) Includes approximately $3 million of net losses and $22 million of net gains that had not been realized through settlements for the quarter and nine months ended September 30, 2009.

The following table reflects the carrying value and fair value of all our financial instruments and derivatives that are measured at fair value:

	September 30, 2009		December 31, 2008	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Long-term financing obligations, including current maturities	$13,972	$13,871	$13,908	$11,227
Marketable securities invested in non-qualified compensation plans	19	19	19	19
Commodity-based derivatives	(315)	(315)	(25)	(25)
Interest rate and foreign currency derivatives	(7)	(7)	85	85
Other	17	17	72	72

As of September 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. During the nine months ended September 30, 2009, we did not have any non-financial assets and liabilities that were recorded at fair value subsequent to their initial measurement.

7. Price Risk Management Activities

Our price risk management activities relate primarily to derivatives entered into to hedge or otherwise reduce (i) the commodity price 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 required documentation. 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.

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 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 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 September 30, 2009 and December 31, 2008, we have production-related derivatives on 353 TBtu and 187 TBtu of natural gas and 727 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. These contracts 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 September 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. These contracts also 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 these natural gas and power contracts, 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 September 30, 2009 and December 31, 2008, we have interest rate swaps designated as cash flow hedges that converted the interest rate on approximately $172 million of debt from a LIBOR-based variable rate to a fixed rate of 4.56%.

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We also 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 record changes in the fair value of these derivatives in interest expense. As of September 30, 2009 and December 31, 2008, we have interest rate swaps designated as fair value hedges that convert 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 September 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 contracts.

Cross-Currency Derivatives. During the second quarter of 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 at fair value on our balance sheet 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 type. We have not netted these contracts 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**	
	September 30, 2009	**December 31, 2008**	**September 30, 2009**	**December 31, 2008**
		(In millions)		
Derivatives Designated as Hedges:				
Cash flow hedges				
Interest rate derivatives	$	$	$ (18)	$ (21)
Fair value hedges				
Interest rate derivatives	11	12		
Cross-currency derivatives		94		
Total derivatives designated as hedges	11	106	(18)	(21)
Derivatives not Designated as Hedges:				
Commodity-based derivatives				
Production-related	408	738	(189)	(56)
Other natural gas	618	853	(798)	(1,122)
Power-related	65	111	(419)	(549)
Total commodity-based derivatives	1,091	1,702	(1,406)	(1,727)
Interest rate derivatives	12	12	(12)	(12)
Total derivatives not designated as hedges	1,103	1,714	(1,418)	(1,739)
Impact of master netting arrangements[(1)]	(689)	(743)	689	743
	425	1,077	(747)	(1,017)

Total assets (liabilities) from price risk management activities				
Other derivatives[2]			(32)	(55)
Total derivatives	$ 425	$ 1,077	$ (779)	$ (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 on 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 designated as cash flow hedges are deferred in accumulated other comprehensive income or loss to the extent 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 not designated as accounting hedges are marked-to-market each period and changes in their fair value are generally reflected in income 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 nine months ended September 30, 2009:

	Operating Revenues	Interest Expense	Other Income (In millions)	Other Comprehensive Income (Loss)
Quarter Ended September 30, 2009				
Commodity-based derivatives				
Production-related derivatives[(1)]	$ 87	$	$	$ (95)
Other natural gas and power derivatives not designated as hedges	(20)			
Total commodity-based derivatives	67			(95)
Interest rate derivatives[(2)]				
Designated as cash flow hedges[(3)]		1		
Designated as fair value hedges[(4)]		1		
Total interest rate derivatives		2		
Total price risk management activities[(5)]	$ 67	$ 2	$	$ (95)
Nine Months Ended September 30, 2009				
Commodity-based derivatives				
Production-related derivatives[(1)]	$ 536	$	$	$ (322)
Other natural gas and power derivatives not designated as hedges	53			
Total commodity-based derivatives	589			(322)
Interest rate and foreign currency derivatives[(2)]				
Designated as cash flow hedges[(3)]		3	(5)	8
Designated as fair value hedges[(4)]		6	(21)	
Total interest rate and foreign currency derivatives		9	(26)	8
Total price risk management activities [(5)]	$ 589	$ 9	$ (26)	$ (314)

(1) Included in operating

revenues for the quarter and nine months ended September 30, 2009 is $95 million and $322 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 $75 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 $2 million and $4 million of losses recognized for the quarter and nine months ended September 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 nine months ended September 30, 2009.

(3) Included in these amounts is approximately $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 nine months ended September 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 $3 million during the quarter and nine months ended September 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 nine months ended September 30, 2009.

(5) We also had approximately $3 million of net losses and $22 million of net gains for the

quarter and nine months ended September 30, 2009 recognized in operating expenses related to other derivative instruments not associated with our price risk management activities.

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8. Debt, Other Financing Obligations and Other Credit Facilities

	September 30, 2009	December 31, 2008
	(In millions)	
Short-term financing obligations, including current maturities	$ 339	$ 1,090
Long-term financing obligations	13,633	12,818
Total	$ 13,972	$ 13,908

Changes in Long-Term Financing Obligations. During the nine months ended September 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	129	121
Ruby Holding Company loan commitment	7.00%	157	154
Ruby Pipeline, LLC term loan	variable	116	115
El Paso Pipeline Partners, L.P. (EPB) revolving credit facilities	variable	138	138
Increases through September 30, 2009		$ 1,390	$ 1,369
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	(188)	(188)
El Paso Exploration and Production Company revolving credit facility	variable	(20)	(20)
Other	variable	33	(14)
Decreases through September 30, 2009		$ (1,326)	$ (1,373)

(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 September 30, 2009, we had total available capacity under various credit agreements (not including capacity available under the EPB $750 million revolving credit facility and all project financings) of approximately $1.4 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 nine months of 2009, we increased the size of or entered into new letter of credit facilities totaling $275 million. As of September 30, 2009, we had total letter of credit capacity under these facilities of $300 million with a weighted average fixed facility fee of 6.77% and maturities ranging from December 2013 to September 2014. Additionally, during 2009, $300 million of letter of credit facilities 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 December 31, 2008, the restricted net assets of our consolidated subsidiaries were 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 September 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 September 30, 2009, we had outstanding letters of credit issued under all of our facilities of approximately $1.5 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. During 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 September 30, 2009, $129 million has been borrowed under this facility. During the third quarter of 2009, Ruby, a consolidated variable interest entity, entered into a loan commitment for $405 million, which is available only to fund the Ruby pipeline project. As of September 30, 2009, $157 million has been borrowed by Ruby under this loan commitment. In addition, during 2008 our wholly owned subsidiary, Ruby Pipeline L.L.C., entered into a letter of credit facility which is available only to secure the purchase of pipe for the Ruby pipeline project and in 2009 this facility was amended to provide up to $145 million in loans. As of September 30, 2009, $116 million has been borrowed under this facility. For a further discussion of Ruby, see Note 13.

9. Commitments and Contingencies

Legal Proceedings

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 the Employee Retirement Income Security Act (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 claims that our plan violated ERISA. 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, the trial court 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 in the first quarter of 2008, 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. 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 which was approved by the court and paid. Our costs and legal exposure related to the remaining lawsuits and claims are not currently determinable.

Gas Measurement Cases. A number of our subsidiaries were named defendants in actions that generally allege mismeasurement of natural gas volumes and/or heating content resulting in the underpayment of royalties. The first set of cases was filed in 1997 by an individual under the False Claims Act 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 October 2009, the plaintiff s appeal to the United States Supreme Court 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 seek certification of a class of royalty owners in wells on non-federal and non-Native American lands in Kansas, Wyoming and Colorado. 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. In September 2009, the court denied the motions for class certification. The plaintiffs have filed a motion for reconsideration. 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. Additionally, in July 2009, we settled an additional case which our insurance covered. Following dismissal of the settled cases we have 32 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 12 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 September 30, 2009, we had approximately $55 million accrued for our outstanding legal and governmental proceedings.

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Rates and Regulatory Matters

EPNG Rate Case. In June 2008, El Paso Natural Gas Company (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 early January 2010. 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 pending the outcome of a hearing. On October 5, 2009, SNG filed with the FERC a settlement of the rate case. The settlement resolved all issues set for hearing and was supported by the FERC Staff and not opposed by the participants associated with the rate case. On October 20, 2009, the Administrative Law Judge assigned to the case certified that the settlement was uncontested. Under the terms of the settlement SNG, (i) increased its base tariff rates, (ii) implemented a volume tracker for gas used in operations, (iii) agreed to file its next general rate case to be effective no earlier than September 1, 2012 and no later than September 1, 2013, and (iv) the vast majority of SNG's firm transportation contracts expiring prior to September 1, 2013 will be extended until August 31, 2013. SNG expects the FERC to approve the settlement in early 2010.

Notice of Proposed Rulemaking. On October 3, 2007, the Minerals Management Service (MMS) issued a notice of proposed rulemaking that is applicable to pipelines located in the Outer Continental Shelf (OCS). If adopted, the proposed rules would substantially revise MMS OCS pipeline and rights-of-way regulations. The proposed rules would have the effect of (i) increasing the financial obligations of entities which have pipelines and pipeline rights-of-way in the OCS, (ii) increasing the regulatory requirements imposed on the operation and maintenance of existing pipelines and rights-of-way in the OCS, and (iii) 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 (the Department) 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 payments under rights-of-way 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 September 30, 2009, we had accrued approximately $195 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 $190 million for expected remediation costs and associated onsite, offsite and groundwater technical studies and approximately $5 million for related environmental legal costs. Of the $195 million accrual, $15 million was reserved for facilities we currently operate and $180 million was reserved for non-operating sites (facilities that are shut down or have been sold) and Superfund sites.

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Our estimates of potential liability range from approximately $195 million to approximately $385 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 ($10 million). Second, where the most likely outcome cannot be estimated, a range of costs is established ($185 million to $375 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:

	September 30, 2009	
Sites	**Expected**	**High**
	(In millions)	
Operating	$ 15	$ 21
Non-operating	164	325
Superfund	16	39
Total	$ 195	$ 385

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

Balance as of January 1, 2009	$ 204
Additions/adjustments for remediation activities	21
Payments for remediation activities	(30)
Balance as of September 30, 2009	$ 195

For the remainder of 2009, we estimate that our total remediation expenditures will be approximately $18 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 $804 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 September 30, 2009, we have recorded obligations of $54 million related to our guarantee and 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 and Other Matters. During the second quarter of 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.

Purchase Obligations. During 2009, we entered into additional contracts to purchase and install approximately $0.4 billion of pipe primarily associated with the Ruby pipeline project and TGP s 300 Line expansion which are anticipated to be placed in service between 2010 and 2011.

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 September 30 are as follows:

	Quarters Ended September 30,				Nine Months Ended September 30,			
	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
	2009	2008	2009	2008	2009	2008	2009	2008
	(In millions)							
Service cost	$ 6	$ 4	$	$	$ 14	$ 11	$	$
Interest cost	31	30	10	10	91	90	29	27
Expected return on plan assets	(43)	(47)	(3)	(4)	(129)	(140)	(9)	(12)
Amortization of net actuarial loss (gain)	12	6		(1)	34	18		(3)
Amortization of prior service credit	(1)	(1)	(1)		(1)	(2)	(1)	(1)
Net benefit cost (income)	$ 5	$ (8)	$ 6	$ 5	$ 9	$ (23)	$ 19	$ 11

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[1]	Convertible Preferred Stock (4.99%/Year)
Amount paid through September 30, 2009	$ 105	$ 28
Amount paid in October 2009	$ 34	$ 9
Dividends declared subsequent to September 30, 2009:		
Date of declaration	November 3, 2009	November 3, 2009
Payable to shareholders on record	December 4, 2009	December 15, 2009
Date payable	January 4, 2010	January 4, 2010

(1) Common stock dividends were paid at $0.05 per share through October 2009. As recently announced, we have reduced our common stock dividends to $0.01 per share beginning with our November 2009 dividend declaration.

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 fourth quarter 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 for all dividends paid during 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. During 2009, our subsidiary EPB, a master limited partnership, issued 12.7 million common units for net proceeds of $212 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. As a result of this acquisition, EPB now owns a 58 percent interest in CIG, a 25 percent interest in SNG and a 100 percent interest in Wyoming Interstate Company (WIC).

12. Business Segment Information

As of September 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 September 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 September 30:

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(In millions)			
Segment EBIT	$ 378	$ 886	$ (478)	$ 1,905
Corporate and other	(20)	(5)	4	75
Interest and debt expense	(256)	(221)	(764)	(675)
Income tax benefit (expense)	(35)	(215)	425	(450)
Net income (loss) attributable to El Paso Corporation	67	445	(813)	855
Net income attributable to noncontrolling interests	15	7	38	23
Net income (loss)	$ 82	$ 452	$ (775)	$ 878

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

	Segments					
	Pipelines	Exploration and Production	Marketing	Power	Corporate and Other[1]	Total
	(In millions)					
Quarter Ended September 30, 2009						
Revenue from external customers	$656	$ 218(2)	$ 107	$	$	$ 981
Intersegment revenue	11	125(2)	(133)		(3)	
Operation and maintenance	209	107	2	5	23	346
Ceiling test charges		5				5
Depreciation, depletion and amortization	104	93			3	200
Earnings (losses) from unconsolidated affiliates	27	(7)		(10)	1	11
EBIT	326	88	(28)	(8)	(20)	358
Quarter Ended September 30, 2008						
	$615	$ 528(2)	$ 450	$	$ 5	$1,598

Revenue from external customers						
Intersegment revenue	13	353[2]	(361)		(5)	
Operation and maintenance	223	89	7	4	5	328
Ceiling test charges		1				1
Depreciation, depletion and amortization	97	191			4	292
Earnings from unconsolidated affiliates	28	10		12	2	52
EBIT	278	532	82	(6)	(5)	881

(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 September 30, 2009 and 2008, we recorded an intersegment revenue elimination of $3 million and $5 million in the Corporate and Other column to remove intersegment transactions.

(2) Revenues from external customers include gains of $87 million and $158 million for the quarters

ended September 30, 2009 and 2008 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.

	Segments					
	Pipelines	Exploration and Production	Marketing	Power	Corporate and Other[1]	Total
			(In millions)			
Nine Months Ended September 30, 2009						
Revenue from external customers	$2,016	$ 977(2)	$ 443	$	$ 2	$3,438
Intersegment revenue	34	375(2)	(401)		(8)	
Operation and maintenance	587	306	7	11	(1)	910
Ceiling test charges		2,085				2,085
Depreciation, depletion and amortization	310	334			9	653
Earnings (losses) from unconsolidated affiliates	73	(29)		(5)	3	42
EBIT	1,049	(1,536)	34	(25)	4	(474)
Nine Months Ended September 30, 2008						
Revenue from external customers	$1,954	$ 856(2)	$ 1,194	$	$ 16	$4,020
Intersegment revenue	40	1,283(2)	(1,308)		(15)	
Operation and maintenance	623	295	17	13	(74)	874
Ceiling test charges		8				8
Depreciation, depletion and amortization	295	600			8	903
Earnings from unconsolidated affiliates	74	36		28	3	141
EBIT	954	1,078	(131)	4	75	1,980

(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 nine months ended September 30, 2009 and 2008, we recorded an intersegment

revenue elimination of $8 million and $16 million in the Corporate and Other column to remove intersegment transactions.

(2) Revenues from external customers include gains of $536 million and losses of $45 million for the nine months ended September 30, 2009 and 2008 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:

	September 30, 2009	**December 31, 2008**
	(In millions)	
Pipelines	$ 16,897	$ 15,121
Exploration and Production	3,904	6,142
Marketing	260	465
Power	207	417
Total segment assets	21,268	22,145
Corporate and Other	889	1,523

Total consolidated assets	$ 22,157	$ 23,668

13. Variable Interest Entities and Qualifying Special Purpose Entities

Variable Interest Entities

We have an investment in Ruby Pipeline Holding Company L.L.C. (Ruby), a variable interest entity that owns our Ruby pipeline project which has approximately $0.4 billion of net property, plant and equipment as of September 30, 2009. We consolidate Ruby as its primary beneficiary based on the conditions discussed below. During the third quarter of 2009, we entered into an agreement with several infrastructure funds managed by Global Infrastructure Partners (GIP), whereby it will invest up to $700 million and acquire a 50 percent interest in Ruby. As part of this agreement, GIP entered into a loan commitment to provide project funding of $405 million to Ruby, which will be converted into a preferred equity interest in Ruby upon satisfaction of certain conditions. As of September 30, 2009, $157 million has been borrowed under this loan commitment.

In October 2009, GIP contributed $145 million to Ruby and received a convertible preferred equity interest in Ruby that was simultaneously exchanged for a convertible preferred equity interest in a holding company of Cheyenne Plains Gas Pipeline Company, L.L.C. (Cheyenne Plains). GIP will hold this interest in Cheyenne Plains until certain conditions are satisfied including placing the Ruby pipeline project in-service. GIP is committed to contribute up to an additional $150 million of preferred equity contributions to Ruby under the conditions that all Federal Energy Regulatory Commission (FERC) approvals for construction of the project are obtained and third party financing of approximately $1.4 billion is secured by Ruby by December 2010. GIP will have the right to convert its preferred equity to common equity in Ruby at any time. However, the preferred equity is subject to a mandatory conversion to common equity in Ruby upon the satisfaction of certain conditions, including Ruby entering into additional firm transportation agreements.

If all conditions to closing are satisfied or waived, at the time of project completion, GIP would own a 50 percent equity interest in Ruby and all ownership in Cheyenne Plains would be transferred back to us. However, the GIP preferred equity interests in Ruby and Cheyenne Plains, along with amounts borrowed under GIP s loan commitment to Ruby, must be repaid in cash to GIP if (i) all FERC approvals for construction of the Ruby pipeline project are not obtained by December 2010, (ii) third party financing of approximately $1.4 billion is not secured by Ruby by December 2010 or (iii) the Ruby pipeline project is not placed in-service within 16 months of obtaining all FERC approvals. Additionally, if the financings are not completed, GIP has the option to convert its preferred interest in Cheyenne Plains to a 50 percent common interest in Cheyenne Plains. Our obligation to repay these amounts is secured by our equity interests in Ruby, Cheyenne Plains, and a portion of approximately 55 million common units we own in our master limited partnership (MLP), El Paso Pipeline Partners, LP.

We hold interests in other variable interest entities that we account for as investments in unconsolidated affiliates. These entities do not have significant operations and accordingly do not have a material impact to our financial statements.

Qualifying Special Purpose Entities

Accounts Receivable Sales Program. Several of our pipeline subsidiaries have agreements to sell certain accounts receivable to qualifying special-purpose entities (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 nine months ended September 30, 2009, we received net proceeds of approximately $0.4 billion and $1.4 billion related to sales of receivables to the QSPEs and changes in our subordinated beneficial interests, and recognized losses of approximately $1 million on these transactions. As of September 30, 2009 and December 31, 2008, we had approximately $152 million and $174 million of receivables outstanding with the QSPEs, for which we received cash of $83 million and $82 million and received subordinated beneficial interests of approximately $68 million and $89 million. The QSPEs also issued senior beneficial interests on the receivables sold to a third party financial institution, which totaled $84 million and $85 million as of September 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 on 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 quarters and nine months ended September 30, 2009 and 2008.

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14. 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		Nine Months Ended	
	September 30, 2009	December 31, 2008	September 30, 2009	September 30, 2008	September 30, 2009	September 30, 2008
	(In millions)		(In millions)			
Net Investment and Earnings (Losses)						
Four Star [1]	$ 465	$ 525	$ (7)	$ 10	$ (29)	$ 36
Citrus	619	564	20	20	54	52
Gulf LNG[2]	282	279	(1)		(2)	
Gasoductos de Chihuahua	177	174	5	8	17	21
Porto Velho[3]		(64)				
Bolivia-to-Brazil Pipeline	99	119	(6)	9	(7)	15
Argentina to Chile Pipeline[4]		27		2	4	5
Other	63	79		3	5	12
Total	$ 1,705	$ 1,703	$ 11	$ 52	$ 42	$ 141

(1) Amortization of our purchase cost in excess of the underlying net assets of Four Star was $12 million and $13 million for the quarters ended September 30, 2009 and 2008 and $37 million and $40 million for the nine months ended September 30, 2009 and 2008.

(2) In February 2008, we acquired a 50 percent interest in Gulf LNG. See Note 2. As of September 30, 2009 and December 31, 2008, we had outstanding advances and receivables of $49 million and $26 million, not included above, related to our investment in Gulf LNG.

(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 Note 2, Acquisitions and Divestitures.

(4) In June 2009, we completed the sale of our investment in the Argentina to Chile Pipeline

as further discussed in Note 2, Acquisitions and Divestitures.

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(In millions)			
Summarized Financial Information				
Operating results data:				
Operating revenues	$124	$196	$382	$576
Operating expenses	58	81	195	258
Income from continuing operations and net income	34	64	93	186

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 $25 million and $48 million for the quarters ended September 30, 2009 and 2008 and $61 million and $129 million for the nine months ended September 30, 2009 and 2008. Included in these amounts are returns of capital of $1 million and $2 million for the quarters and nine months ended September 30, 2009 and returns of capital of less than $1 million for the same periods in 2008. Our revenues and charges with unconsolidated affiliates were not material during the quarters and nine months ended September 30, 2009 and 2008.

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Other Investment-Related Matters

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 September 30, 2009, we have approximately $65 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 $63 million related to plant maintenance the purchaser claims should have been performed at the plants prior to the transfer, inventory levels and other items. The purchaser s parent has also withheld payment of these receivables under its guarantee in light of these claims. We have initiated legal action against the purchaser s parent for their failure to pay us under the performance guaranty, and the purchaser s parent has filed motions with the Brazilian courts to have the power purchaser added as a defendant to that litigation. Settlement discussions with the purchaser and its parent have been unsuccessful to date, and we currently anticipate that resolution of each of these matters will likely occur through the legal proceedings in the Brazilian courts. 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 $65 million of Brazilian reais-denominated ICMS taxes allegedly due on capacity payments received from the plants power purchaser from 1999 to 2001 and secured a court order prohibiting our subsidiaries from transferring or otherwise disposing of any assets. We believe that these ICMS tax assessments on the projects are without merit. 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 has appealed the court s decision. If the power purchaser is unable to resolve this tax matter, any potential taxes owed by the Manaus and Rio Negro projects are also guaranteed by the purchaser s parent.

Bolivia-to-Brazil. We own an 8 percent interest in the Bolivia-to-Brazil pipeline. As of September 30, 2009, our total investment and guarantees related to this pipeline project was approximately $112 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.

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 nine months of 2009, both our pipeline and exploration and production operations continued to provide a strong base of earnings and significant operating cash flow. In late 2008, we outlined our plan to respond to the volatility in the financial markets, energy industry and the global economy while retaining our long-term growth potential comprised of our committed pipeline project backlog and our core domestic and international drilling programs, as well as our natural gas and oil resource positions. Since that time we have executed on that plan by securing significant financing for our pipeline backlog, entering into a partnering agreement on our Ruby pipeline project, and managing our exposure to a volatile commodity price environment through an expanded hedging program, among other actions. We believe that the stability of our pipeline earnings coupled with the hedging program in our exploration and production business, will continue to protect our earnings base and operating cash flow despite economic conditions and the current commodity price environment.

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 continue to grow our pipeline business through expansions of our existing pipeline systems, as well as greenfield projects. During 2009, we have placed four growth projects in-service. In addition, our backlog of growth projects at September 30, 2009, is approximately $6 billion (net to our ownership interest) of which we have spent approximately $2 billion inception-to-date on these projects. We expect to place these projects in-service over the next several years. We have significantly mitigated the risk associated with our remaining backlog by (i) entering into an agreement with several infrastructure funds managed by GIP, whereby it will invest up to $700 million in our Ruby pipeline project (ii) subscribing approximately 90 percent of the capacity of our aggregate backlog under contract terms of 10-30 years primarily with investment-grade customers and (iii) purchasing or committing to purchase steel at fixed prices for all of our largest projects as well as contracting for a significant portion of the construction costs. Finally, we remain focused on growing our MLP.

In our exploration and production business, we continued to generate significant positive operating cash flow during the quarter despite a lower level of drilling activity, lower commodity prices and a reduction in capital spending in 2009. Although it impacts our near-term growth profile, the reductions in our 2009 capital program have been managed to retain substantially all of our existing natural gas and oil resource positions for future exploration and production when commodity prices return to more favorable levels. The derivatives we have in place related to our 2009-2011 production provide significant downside protection to sustain us through the current commodity price environment while still allowing upside potential should prices recover. As of September 30, 2009, we had 40 TBtu of natural gas hedges with an average floor price of $9.02 per MMBtu, 32 TBtu of natural gas hedges with an average ceiling price of $14.35 per MMBtu and 727 MBbls of crude oil swaps at $56.48 per barrel on our remaining anticipated 2009 production. During the first nine months of 2009, we settled all of our $110.00 per barrel 2009 fixed price oil swaps, receiving approximately $186 million in cash. Due to lower natural gas prices at the end of the first quarter of 2009, we recorded approximately $2.1 billion of non-cash ceiling test charges, primarily in our domestic full cost pool, which significantly impacted our earnings for 2009. If commodity prices decrease from the September 30, 2009 levels, we may be required to record additional ceiling test charges in the future. Throughout 2009 we have also implemented numerous cost saving measures including additional cost reductions in our capital and maintenance programs by renegotiating contracts with contractors, suppliers, and service providers, and deferring or eliminating various discretionary costs.

As of September 30, 2009, we had approximately $2.4 billion of available liquidity (see additional discussion in *Liquidity and Capital Resources)*. Our 2009 capital program is estimated to total approximately $3.1 billion, $2 billion of which relates to our pipeline business and approximately $1 billion relates to our exploration and production business. We expect to invest approximately $1 billion of capital during the last quarter of 2009. Our remaining debt maturities in 2009 are not material and in 2010 we have approximately $250 million of debt (excluding Ruby debt which we anticipate will convert into Ruby preferred equity) that will mature.

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Although the financial and commodity markets have shown signs of improvement, they remain volatile. We currently expect that the volatility in the financial markets and commodity markets will continue for the fourth quarter of 2009 and beyond. In light of this continued volatility, we recently announced additional steps we are taking to further improve our financial flexibility to fund our core businesses. These steps include:

- A reduction of $150 million in annual operating and administrative expenses achieved primarily by reducing internal costs and improving efficiencies from leveraging a consolidated supply chain organization. We expect to achieve a portion of our overall projected savings associated with these measures beginning in 2009. In conjunction with the efforts, we also estimate that we will incur approximately $25 million to $30 million in one-time reorganization costs primarily in 2009;

- The sale of $300 million to $500 million of assets during 2010; and

- A reduction in our quarterly dividend from $0.05 per share to $0.01 per share, which will result in annual cash savings of approximately $112 million.

The additional steps we are taking to further improve our financial flexibility to fund our core businesses are designed to (i) provide incremental funding for our 2010 capital programs focused on our pipeline backlog of growth opportunities and unconventional natural gas drilling inventory in our exploration and production business, (ii) improve our overall cost structure, (iii) protect our credit profile and (iv) enhance our returns.

We currently expect that the 2010 capital budget for our exploration and production business will be comparable with our 2009 total spending level, with approximately one-half of the capital program targeted for our Haynesville, Altamont and Eagle Ford areas. In our pipeline business, we currently estimate that the 2010 capital budget will increase from our 2009 capital program, primarily due to the anticipated construction of our Ruby pipeline project. For reporting purposes, during the construction phase, Ruby is consolidated; however after the pipeline is placed in-service, Ruby will be reported as an equity investment.

In October 2009, we announced our re-entry into the midstream business where we believe that the movement to more unconventional supply basins will present future opportunities. In addition, we believe that we may have unique organic growth opportunities where we can leverage our existing competencies and the existing footprints of our pipeline and exploration and production businesses. We intend to re-enter the business at a measured pace, consistent with our overall liquidity and capital constraints.

We will continue to have additional funding requirements for our capital program in 2010 and will be opportunistic in accessing the capital markets. We will also continue to assess and take further actions where warranted to meet our objectives, as well as to address further changes in the financial and commodity markets which may include limited access to the capital markets during certain periods and commodity prices lower than current forecasts.

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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 remaining 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 September 30:

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(In millions)			
Segment				
Pipelines	$ 326	$ 278	$ 1,049	$ 954
Exploration and Production	88	532	(1,536)	1,078
Marketing	(28)	82	34	(131)
Power	(8)	(6)	(25)	4
Segment EBIT	378	886	(478)	1,905
Corporate and other	(20)	(5)	4	75
Consolidated EBIT	358	881	(474)	1,980
Interest and debt expense	(256)	(221)	(764)	(675)
Income tax benefit (expense)	(35)	(215)	425	(450)
Net income (loss) attributable to El Paso Corporation	67	445	(813)	855
Net income attributable to noncontrolling interests	15	7	38	23
Net income (loss)	$ 82	$ 452	$ (775)	$ 878

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Pipelines Segment

Overview and Operating Results. During the first nine months of 2009, we continued to deliver strong operational and financial performance in our Pipelines segment. Our EBIT for the quarter and nine months ended September 30, 2009 increased 17 percent and 10 percent from the same periods for 2008. In the first nine months of 2009, we benefited from several expansion projects placed in service in 2008 and 2009, stronger revenues due to increased re-contracting and marketing efforts, higher volumes of gas not used in operations and effective cost control. Below are the operating results for our Pipelines segment as well as a discussion of factors impacting EBIT for the periods ended September 30, 2009 and 2008, or that could potentially impact EBIT in future periods.

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(In millions, except for volumes)			
Operating revenues	$ 667	$ 628	$ 2,050	$ 1,994
Operating expenses	(373)	(387)	(1,104)	(1,133)
Operating income	294	241	946	861
Other income, net	47	44	141	117
EBIT before adjustment for noncontrolling interests	341	285	1,087	978
Net income attributable to noncontrolling interests	(15)	(7)	(38)	(24)
EBIT	$ 326	$ 278	$ 1,049	$ 954
Throughput volumes (BBtu/d)[(1)]	17,757	18,905	18,460	18,736

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

	Quarter Ended September 30, 2009 Variance				Nine Months Ended September 30, 2009 Variance			
	Operating Revenue	Operating Expense	Other	EBIT Impact	Operating Revenue	Operating Expense	Other	EBIT Impact
	Favorable/(Unfavorable) (In millions)							
Expansions	$ 30	$ (6)	$ 9	$ 33	$ 73	$ (16)	$ 30	$ 87
Reservation and usage revenues	(4)			(4)	22			22
Gas not used in operations and	8	13		21	6	23		29

revaluations								
Bankruptcy proceeds	(1)	(1)		(2)	(45)	(2)		(47)
Loss on long-lived assets		(2)		(2)		22		22
Operating and general and administrative expenses		13		13		15		15
Hurricanes	7	4		11	7	(1)		6
Net income attributable to noncontrolling interests			(8)	(8)			(14)	(14)
Other[1]	(1)	(7)	(6)	(14)	(7)	(12)	(6)	(25)
Total impact on EBIT	$ 39	$ 14	$ (5)	$ 48	$ 56	$ 29	$ 10	$ 95

(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 and 2009 including the Medicine Bow expansion, the High Plains Pipeline, the Carthage Expansion and the Totem Gas Storage project.

We continue to make progress on our backlog of expansion projects, spending approximately $1 billion during the nine months ended September 30, 2009 and approximately $2 billion inception-to-date on these projects. The capacity of our backlog of expansion projects is approximately 90 percent subscribed with contract terms of 10-30 years and will be placed in-service over the next several years. In addition, financings have been completed to fund our $1.6 billion expansion capital plan in 2009 and a substantial portion of the capital needs for the Gulf LNG, Florida Gas Transmission (FGT) Phase VIII and Ruby projects. During 2009, we have placed four growth projects in-service and expect three additional projects, representing $1.0 billion of our expansion backlog, to be placed in-service by the end of 2010.

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

WIC Piceance Lateral Expansion. In September 2009, our WIC Piceance Lateral Expansion project was placed in-service.

WIC Systems Expansion. In July and November 2009, WIC filed applications with the FERC for certificate authorization to construct the WIC expansion project.

CIG Raton 2010 Expansion. During the first quarter of 2009, we agreed with our customers to defer the targeted in-service date for our Raton 2010 project from June 2010 to December 2010. In September 2009, CIG filed an application with the FERC for certificate authorization for this project.

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

Concord Lateral Expansion. In October 2009, our Concord Lateral Expansion project was placed in-service.

TGP 300 Line Expansion. In July 2009, TGP filed an application with the FERC for certificate authorization for its 300 Line Expansion project to add firm transportation capacity to its existing pipeline system in the northeast U.S. market area. All of the firm transportation capacity resulting from this project is fully subscribed with one shipper based on a precedent agreement which was executed in the third quarter of 2009. In October 2009, we entered into a pipeline installation contract for approximately $194 million.

Ruby Pipeline Project. We expect that the Ruby pipeline project will consist of approximately 680 miles of 42 pipeline and multiple compressor stations with total horsepower of approximately 157,000; however, final sizing will be based on market support. In June 2009, the FERC issued a draft Environmental Impact Statement (EIS) related to our Ruby pipeline project, which is expected to be issued in final form in January 2010. In September 2009, we received a Preliminary Determination from the FERC on non-environmental issues related to this project. Subject to FERC approval, the project is anticipated to be placed in-service during the first quarter of 2011.

As discussed further in *Liquidity and Capital Resources* below, in August 2009, we entered into an agreement with GIP, whereby it will invest up to $700 million in the Ruby pipeline project. We have also selected a financial advisor and in conjunction with our partner, we have begun working through a financing plan.

FGT Phase VIII Project. In September 2009, the FERC issued a final EIS. We also received the Pipeline and Hazardous Materials Safety Administration special permit from the Department of Transportation in order to operate the pipeline at higher operating pressures.

South System III and Southeast Supply Header Phase II. In August 2009, we received certificates of authorization from the FERC on the South System III and the Southeast Supply Header Phase II projects.

Elba Expansion III/ Elba Express/ Cypress Phase III. During the second quarter of 2009, BG LNG Services LLC (BG) and SNG, Elba Express 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 December 31, 2014, or, in the event certain conditions are unable to be met by BG, to terminate the Elba III Phase B expansion. In exchange for this delay/termination option, BG has committed to subscribe to certain firm Phase B capacity on El Paso s Elba Express pipeline and to 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.

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In addition to our backlog of contracted organic growth projects, we have other projects that are in various phases of commercial development. 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. In early 2009, SNG executed a non-binding letter of intent (LOI) with Florida Power & Light Company (FPL) to expand SNG s pipeline system by approximately 600 MMcf/d by constructing approximately 375 miles of 36-inch pipeline from western Alabama to northern Florida. This expansion project was subject to the Florida Public Service Commission s (PSC) approval for FPL to build an intrastate pipeline which would connect to our SNG system. The PSC rejected FPL s proposal and SNG s LOI with FPL has expired. The future of this project is uncertain.

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.

Reservation and Usage Revenues. During the quarter ended September 30, 2009, our reservation and usage revenues decreased slightly as compared to the same period in 2008 primarily due to lower volumes delivered and lower average system rates in our TGP system. During the nine months ended September 30, 2009, our overall EBIT was favorably impacted by (i) increased reservation and other services revenues on our EPNG system during the first nine 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 from the Marcellus Basin in the northeast market area of our TGP system.

For the nine months ended September 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 northeast and southwest. 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 on certain of our pipelines with the FERC to recover our prudently incurred costs.

Gas Not Used in Operations and Revaluations. During the quarter and nine months ended September 30, 2009, our overall EBIT was favorably impacted by $13 million and $32 million primarily due to retained fuel volumes in excess of fuel used in operations, higher realized prices on operational sales and lower electric compression utilization in one of our pipelines. In addition, during the quarter ended September 30, 2009, our overall EBIT was favorably impacted by $5 million primarily due to favorable revaluation of retained volumes on our SNG system. Effective September 1, 2009, a volume tracker was implemented as part of SNG s rate case settlement as further discussed below, therefore our SNG system no longer shares retained gas not used in operations.

In addition, during the quarter and nine months ended September 30, 2008, CIG and WIC recorded cost and revenue tracker adjustments associated with the implementation of fuel and related gas cost recovery mechanisms, which the FERC approved subject to the outcome of technical conferences. The implementation of these mechanisms was protested by a limited number of shippers. On July 31, 2009, and October 1, 2009, the FERC issued orders to CIG and WIC, respectively, directing us to remove the cost and revenue components from their fuel recovery mechanisms. Due to these orders, our future earnings may be impacted by both positive and negative fluctuations in gas prices related to fuel imbalance revaluations, their settlement, and other gas balance related items. We continue to explore options to minimize the price volatility associated with these operational pipeline activities.

On October 1, 2009, EPNG received an order from the FERC directing EPNG to modify the cost and revenue component of its fuel recovery mechanism. EPNG is seeking rehearing and clarification of certain aspects of this order; however, we do not believe that this order will have any negative effect to previously reported earnings. Due to the order, our future earnings may be impacted by both positive and negative fluctuations in gas prices related to fuel imbalance revaluations, their settlement, and other gas balance related items. We continue to explore options to minimize the price volatility associated with these operational pipeline activities.

Bankruptcy Proceeds. During the nine months ended September 30, 2008, we (i) recorded income of approximately $8 million as a result of settlements received from the Enron Corporation bankruptcy and (ii) recognized revenue of $39 million related to Calpine s rejection of its transportation contracts with us primarily associated with distributions received under Calpine Corporation s approved plan of reorganization. The impact of bankruptcy proceeds for the quarters ended September 30, 2009 and 2008 was not material.

Loss on Long-Lived Assets. During the nine months ended September 30, 2008, we recorded impairments of $24 million, primarily related to our Essex-Middlesex Lateral project due to a prolonged permitting process. There were no significant impairments recorded for the quarters ended September 30, 2009 and 2008.

Operating and General and Administrative Expenses. For the quarter and nine months ended September 30, 2009, our operating and general and administrative expenses were lower than the same periods in 2008 primarily due to approximately $17 million and $33 million of decreased field repair and maintenance expense on several of our pipeline systems. Partially offsetting these cost reductions were increases of approximately $9 million and $20 million in accrued benefit costs for the quarter and nine months ended September 30, 2009.

Hurricanes. During the third quarter of 2008, we incurred damage to sections of our Gulf Coast and offshore pipeline facilities due to Hurricanes Ike and Gustav. For the quarter and nine months ended September 30, 2008, our EBIT was unfavorably impacted by these hurricanes due to gas loss from various damaged pipelines, lower volume of gas not used in operations, lower usage revenue and repair costs that will not be recoverable from insurance due to losses not exceeding self-retention levels. We continue to evaluate whether to repair or retire those damaged facilities. See *Liquidity and Capital Resources* for a further discussion of these hurricanes.

Net Income Attributable to Noncontrolling Interests. During the quarter and nine months ended September 30, 2009, our net income attributable to noncontrolling interests increased as compared to the same period in 2008 due to (i) the additional public common units issued by our majority-owned MLP and (ii) our contribution of additional interests in CIG and SNG to our MLP. In July 2009, we contributed an additional 18 percent interest in CIG to the MLP and in September 2008 we contributed an additional 15 percent interest in SNG and 30 percent interest in CIG to our MLP. As of September 30, 2009, our MLP owns 58 percent of CIG, 25 percent of SNG and 100 percent of WIC.

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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 from 2011 through 2013.

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 early January 2010. 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 pending the outcome of a hearing. On October 5, 2009, SNG filed with the FERC a settlement of the rate case. The settlement resolved all issues set for hearing and was supported by the FERC Staff and not opposed by the participants associated with the rate case. On October 20, 2009, the Administrative Law Judge assigned to the case certified that the settlement was uncontested. Under the terms of the settlement SNG, (i) increased its base tariff rates, (ii) implemented a volume tracker for gas used in operations, (iii) agreed to file its next general rate case to be effective no earlier than September 1, 2012 and no later than September 1, 2013, and (iv) the vast majority of SNG s firm transportation contracts expiring prior to September 1, 2013 will be extended until August 31, 2013. SNG expects the FERC to approve the settlement in early 2010.

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. During 2009, our focus has shifted to more unconventional resource plays including the Haynesville Shale in northwest Louisiana and east Texas, Eagle Ford Shale in south Texas, and Altamont tight oil in Utah. 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. During the second quarter of 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.

During 2009, the industry experienced reductions in the market price of natural gas from those levels at December 31, 2008. Service and equipment costs also declined, but not at levels commensurate with the reduction in natural gas prices. Based on reduced commodity prices and service equipment costs, we recorded non-cash ceiling test charges of approximately $2.1 billion during the first quarter of 2009. The challenging commodity price environment continues to put pressure on our economic assumptions related to new development and exploration projects in 2009. Coupled with unprecedented challenges in the credit markets, these events resulted in us reducing our capital spending during 2009. Based on these lower spending levels, we expect our annual 2009 production volumes to be down six percent to eight percent from 2008.

Significant Operational Factors Affecting the Periods Ended September 30, 2009

Production. Our average daily production for the nine months ended September 30, 2009 was 698 MMcfe/d (which does not include 72 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 September 30:

	Nine Months Ended September 30,	
	2009	**2008**
	MMcfe/d	
United States		
Central	252	238
Western	158	153
Gulf Coast	279	361
International		
Brazil	9	11
Total Consolidated	698	763
Four Star	72	74

In the first nine 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 Altamont area. In the Haynesville Shale, we have drilled 11 wells and currently have net production of approximately 50 MMcfe per day. In the Altamont area, we drilled four wells in 2009. 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 this division, however, our 2009 focus has been on increasing our Eagle Ford Shale acreage, where we hold approximately 112,000 net acres and drilled our first well which was successful. In Brazil, our production volumes decreased primarily due to natural production declines.

2009 Drilling Results

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

Central. We achieved a 100 percent success rate on 108 gross wells drilled.

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

Gulf Coast. We achieved an 80 percent success rate on 25 gross wells drilled.

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

Camamu Basin. During the first nine 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 receiving these approvals and achieving estimated cost reductions that reflect the current commodity price environment.

In 2009, we relinquished our interest in the BM-CAL-6 block following unsuccessful exploration activities in 2008. In the BM-CAL-5 block, we continue to evaluate and search for viable commercial options to develop the resources found by two exploration wells. We, along with the operator, Petrobras, are currently evaluating the areas to retain in this block in advance of the November 2009 contractual relinquishment date. We continue to own a 20 percent interest in two additional blocks in the Camamu basin, CAL-M-312 and CAL-M-372, which are located east of and contiguous to the BM-CAL-5 and BM-CAL-6 blocks. We will be further evaluating these two blocks over the next several years.

Espirito Santo Basin. In the Camarupim Field, we began natural gas and condensate production in October 2009 from the first of four horizontal wells after resolving problems with facilities that delayed the start up of production. We continue to work with the operator, Petrobras, in addressing similar problems in connecting the remaining three wells and anticipate ramping up production from the field in late 2009 and in 2010.

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. By the end of 2009, we plan to participate with Petrobras in spudding another exploratory well in the ES-5 block to evaluate an additional prospect.

During the first nine months of 2009, we added approximately 84 Bcfe of reserves in Brazil and, as of September 30, 2009, have total capitalized costs of approximately $336 million, of which $143 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 $26 million in our full cost pool, including $5 million in the third quarter of 2009. In addition, CEPSA Egypt S.A. B.V. (CEPSA), the operator of the South Alamein block, completed drilling two wells in the block where hydrocarbons were discovered. These wells are currently being evaluated. We also participated with CEPSA in drilling a third exploratory well on the block which was unsuccessful, and we have plans to spud a fourth exploratory well in the block by the end of 2009. As of September 30, 2009, we have total capitalized costs of approximately $69 million in Egypt, all of which are unevaluated.

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 and other 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 nine months ended September 30, 2009, cash operating costs per unit were $1.83/Mcfe as compared to $1.94/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 $740 million for the nine months ended September 30, 2009, of which $531 million were domestic capital expenditures.

Outlook for 2009

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

Capital expenditures, excluding acquisitions, of approximately $1 billion. Of this total, we expect to spend approximately $750 million on our domestic program and approximately $250 million in Brazil and Egypt.

Average daily production volumes for the year of approximately 680 MMcfe/d to 695 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 average between 10 MMcfe/d and 15 MMcfe/d in 2009.

Average cash operating costs of approximately $1.85/Mcfe to $1.95/Mcfe for the year.

Depreciation, depletion and amortization rate of between $1.70/Mcfe and $1.80/Mcfe, which includes the impact of our 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 commodity price exposure, our reported results of operations, financial position and cash flows can be impacted significantly by commodity price movements 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 nine months of 2009, we settled all of our $110.00 per barrel 2009 fixed price oil swaps, receiving approximately $186 million in cash and entered into new fixed price oil swaps on 1,866 MBbls of our anticipated 2009 oil production at an average price of $50.93 per barrel. We also entered into additional option and basis swap contracts on our 2009, 2010 and 2011 natural gas production and swaps on our 2010 oil production. During the first nine months of 2009, we paid $173 million in premiums to enter into these contracts. The following table reflects the contracted volumes and the minimum, maximum and average prices we will receive under our derivative contracts as of September 30, 2009.

	Fixed Price						Basis Swaps[1][2]							
							Texas Gulf		Western				Central	
	Swaps[1]		Floors[1]		Ceilings[1]		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	2	$ 7.37	38	$9.11	30	$14.83	14	$(0.34)	6	$(0.96)	3	$(2.01)	3	$(1.04)
2010	52	$ 6.19	123	$6.50	60	$ 8.14	48	$(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	727	$56.48												

(1) Volumes presented are TBtu for natural gas and MBbl for oil. Prices presented are

per MMBtu of natural gas and per Bbl of oil.

(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.

In October 2009, we entered into 2,373 MBbls of fixed price swaps on a portion of our anticipated 2010 oil production at an average price of $74.63/Bbl.

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 September 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.

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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 nine months ended September 30:

	Quarters Ended September 30, 2009	Quarters Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
	(In millions)			
Physical sales:				
Natural gas	$ 175	$ 543	$ 603	$ 1,649
Oil, condensate and NGL	70	157	184	482
Total physical sales	245	700	787	2,131
Realized and unrealized gains (losses) on financial derivatives[1]	87	158	536	(45)
Other revenues	11	23	29	53
Total operating revenues	343	881	1,352	2,139
Operating expenses:				
Cost of products	8	13	21	28
Transportation costs	15	23	50	63
Production costs	61	96	193	280
Depreciation, depletion and amortization	93	191	334	600
General and administrative expenses	44	26	145	116
Ceiling test charges	5	1	2,085	8
Impairment of inventory	16		16	
Other	4	3	10	9
Total operating expenses	246	353	2,854	1,104
Operating income (loss)	97	528	(1,502)	1,035
Other income (expense)[2]	(9)	4	(34)	43
EBIT	$ 88	$ 532	$ (1,536)	$ 1,078

(1) Includes $95 million and $(66) million for the quarters ended September 30, 2009 and 2008 and $322 million and $(127) million for the

nine months ended September 30, 2009 and 2008, reclassified from accumulated other comprehensive income associated with accounting hedges.

(2) 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 our derivative contracts.

	Quarters Ended September 30,			Nine Months Ended September 30,		
	2009	2008	Percent Variance	2009	2008	Percent Variance
Consolidated volumes, prices and costs per unit:						
Natural gas						
Volumes (MMcf)	52,805	56,609	(7)%	164,728	178,688	(8)%
Average realized price on physical sales ($/Mcf)	$ 3.32	$ 9.58	(65)%	$ 3.66	$ 9.23	(60)%
Average realized price, including financial derivative settlements ($/Mcf) (1)	$ 7.37	$ 8.67	(15)%	$ 7.67	$ 8.60	(11)%
Average transportation costs ($/Mcf)	$ 0.24	$ 0.37	(35)%	$ 0.28	$ 0.32	(13)%
Oil, condensate and NGL						
Volumes (MBbls)	1,336	1,571	(15)%	4,296	5,079	(15)%
Average realized price on physical sales ($/Bbl)	$ 52.22	$ 99.77	(48)%	$ 42.72	$ 94.81	(55)%
Average realized price, including financial derivative settlements ($/Bbl) (1) (2)	$ 82.25	$ 88.13	(7)%	$ 75.66	$ 84.17	(10)%
Average transportation costs ($/Bbl)	$ 0.80	$ 1.18	(32)%	$ 0.85	$ 0.97	(12)%
Total equivalent volumes						
MMcfe	60,825	66,033	(8)%	190,505	209,161	(9)%
MMcfe/d	661	718	(8)%	698	763	(9)%
Production and other cash operating costs ($/Mcfe)						
Average lease operating expenses	$ 0.77	$ 0.96	(20)%	$ 0.76	$ 0.85	(11)%
Average production taxes(3)	0.24	0.50	(52)%	0.26	0.49	(47)%
Total production costs	$ 1.01	$ 1.46	(31)%	$ 1.02	$ 1.34	(24)%
Average general and administrative expenses	0.73	0.38	92%	0.76	0.56	36%
Average taxes, other than production and income taxes	0.04	0.05	(20)%	0.05	0.04	25%
Total cash operating costs	$ 1.78	$ 1.89	(6)%	$ 1.83	$ 1.94	(6)%
Depreciation, depletion and amortization ($/Mcfe)	$ 1.54	$ 2.89	(47)%	$ 1.75	$ 2.87	(39)%
Unconsolidated affiliate volumes (Four Star):						
Natural gas (MMcf)	4,823	5,351		14,726	15,399	
Oil, condensate and NGL (MBbls)	282	263		841	797	
Total equivalent volumes						
MMcfe	6,515	6,929		19,774	20,180	

MMcfe/d	71	75	72	74

(1) Premiums related to natural gas derivatives settled during the quarter and nine months ended September 30, 2008 were $6 million and $16 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 nine months ended September 30, 2008. We had no premiums related to natural gas derivatives settled during the quarter and nine months ended September 30, 2009 or related to oil derivatives settled during the quarters and nine months ended September 30, 2009 and 2008.

(2) Amounts for the quarter and nine months ended September 30, 2009, include approximately $50 million and $137 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 include the remaining $49 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 Nine Months Ended September 30, 2009 Compared to Quarter and Nine Months Ended September 30, 2008

Our EBIT for the quarter and nine months ended September 30, 2009 decreased $0.4 billion and $2.6 billion as compared to the same periods in 2008. The table below shows the significant variances in our financial results for the periods ended September 30, 2009 as compared to the same periods in 2008:

	Quarter Ended September 30, 2009				Nine Months Ended September 30, 2009			
	Variance				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	$ (331)	$	$	$ (331)	$ (917)	$	$	$ (917)
Lower volumes in 2009	(37)			(37)	(129)			(129)
Oil, condensate and NGL								
Lower realized prices in 2009	(64)			(64)	(224)			(224)
Lower volumes in 2009	(23)			(23)	(74)			(74)
Realized and unrealized gains/(losses) on financial derivatives	(71)			(71)	581			581
Other revenues	(12)			(12)	(24)			(24)
Depreciation, depletion and amortization expense								
Lower depletion rate in 2009		84		84		215		215
Lower production volumes in 2009		14		14		51		51
Production costs								
Lower lease operating expenses in 2009		17		17		34		34
Lower production taxes in 2009		18		18		53		53
General and administrative expenses		(18)		(18)		(29)		(29)
Ceiling test charges		(4)		(4)		(2,077)		(2,077)
Impairment of inventory		(16)		(16)		(16)		(16)
Earnings from investment in Four Star			(16)	(16)			(65)	(65)
Other		12	3	15		19	(12)	7
Total variances	$ (538)	$ 107	$ (13)	$ (444)	$ (787)	$ (1,750)	$ (77)	$ (2,614)

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

Realized and unrealized gains/(losses) on financial derivatives. During the quarter and nine months ended September 30, 2009, we recognized gains of $87 million and $536 million compared to gains of $158 million and losses of $45 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.

General and administrative expenses. Our general and administrative expenses increased during 2009 as compared to the same periods in 2008 primarily due to the reversal of a $20 million accrual in 2008 as a result of a favorable ruling on a legal matter.

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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. During the nine months ended September 30, 2009, we recorded total non-cash ceiling test charges of $2.1 billion. Due to low natural gas and oil prices in the first quarter of 2009, we experienced a downward price-related reserve revision of approximately 400 Bcfe (primarily in our Arklatex, Raton and Mid-Continent areas) and recorded non-cash ceiling test charges of approximately $2.0 billion related to our domestic full cost pool, $28 million to our Brazilian full cost pool and $9 million to our Egyptian full cost pool related to a dry hole drilled in the South Mariut block.

During the second and third quarters of 2009, natural gas prices remained low, but the combination of a recovery in oil prices, reserve additions from our drilling programs principally in the Haynesville Shale and Altamont areas, and lower operating and capital costs resulted in no ceiling test charges in our domestic full cost pool in those periods. As of September 30, 2009, spot natural gas prices were $3.30 per MMBtu while oil prices were $70.61 per barrel. In Brazil, higher fuel oil prices which favorably impact the natural gas price on our Camarupim production, and reserve additions at our Camarupim Field also resulted in no ceiling test charges in Brazil in the second and third quarters of 2009. In Egypt, we recorded ceiling test charges of $12 million during the second quarter of 2009 related to dry hole costs and $5 million during the third quarter of 2009 related to fees associated with the buyout of a drilling rig contract as we further assess the results of our drilling programs. Although we did not incur a domestic or Brazilian ceiling test charge during the third quarter of 2009, we will continue to monitor commodity prices since sustained lower commodity prices and other factors could result in ceiling test charges in future periods.

Impairment of inventory. In the third quarter of 2009, we recorded a $16 million non-cash charge to reflect the current market price we expect to receive upon the sale of certain casing and tubular goods inventory (materials and supplies), which prior to the third quarter, we intended to use in our capital programs. Based on changes to our capital program we decided in the third quarter of 2009 to sell this inventory and use the proceeds to purchase inventory related to our current capital projects.

Other. Our equity earnings from Four Star decreased by $16 million and $65 million during the quarter and nine months ended September 30, 2009 as compared to the same periods in 2008 primarily due to lower commodity prices.

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 quarter ended September 30, 2009, we generated an EBIT loss of $28 million primarily due to mark-to-market losses on our natural gas and power contracts due to decreases in interest rates. During the nine months ended September 30, 2009, we generated EBIT of $34 million primarily due to mark-to-market gains in the first quarter of 2009 of approximately $52 million related to the application of new accounting standard updates on our derivative liabilities that have non-cash collateral associated with them, such as letters of credit. For a further description of these updates, see Item 1, Financial Statements, Note 1. Below is further information about our overall operating results during each of the quarters and nine months ended September 30:

	Quarters Ended September 30,		Nine Months Ended September 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	$	$ 14	$	$ (59)
Contracts Related to Legacy Trading Operations:				
Changes in fair value of power contracts	(6)	63	49	(83)
Natural gas transportation-related contracts:				
Demand charges	(9)	(8)	(26)	(27)
Settlements, net of termination payments	3	13	15	37
Changes in fair value of other natural gas derivative contracts[1]	(14)	7	4	18
Total revenues	(26)	89	42	(114)
Operating expenses	(2)	(7)	(8)	(18)
Operating income (loss)	(28)	82	34	(132)
Other income, net				1
EBIT	$ (28)	$ 82	$ 34	$ (131)

(1) Includes $17 million and

$19 million of revenue for the quarter and nine months ended September 30, 2008 related to bankruptcy settlements.

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 nine months ended September 30, 2008, increases in commodity prices reduced the fair value of these contracts resulting in losses, whereas during the quarter ended September 30, 2008, decreases in commodity prices increased the fair value of these contracts resulting in gains.

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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 nine months ended September 30, 2009, we recognized mark-to-market gains of $49 million, which includes a $33 million gain recorded in the first quarter related to the application of new accounting standard updates on certain of our derivative liabilities. During the third quarter of 2009, our mark-to-market losses on these contracts primarily related to decreases in interest rates. During the nine months ended September 30, 2008, we recognized mark-to-market losses of $83 million primarily resulting from increases in locational PJM power price differences and interest rates. However, during the third quarter of 2008, we recorded mark-to-market gains on these contracts of $63 million as the locational difference in forward power prices decreased during the quarter. Also impacting our results for the nine months ended September 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 September 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 $10 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 $4 million recognized for the nine months ended September 30, 2009 includes a $19 million gain in the first quarter of 2009 related to the application of new accounting standard updates on certain of our derivative liabilities.

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Power Segment

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

Area	
South America	
Manaus & Rio Negro	$ 51
Bolivia-to-Brazil Pipeline	112
Asia	5
Total	$ 168

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 Brazilian reais-denominated receivables due from the power purchaser. We are also in the process of trying to resolve several outstanding claims denominated in Brazilian reais relating to these projects. In the first quarter of 2009, we completed the sale of our investment 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. 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, the Manaus and Rio Negro receivables are collected or matters further discussed in Item 1, Financial Statements, Note 14 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 nine months ended September 30, 2009, our Power segment generated EBIT losses of $8 million and $25 million compared to an EBIT loss of $6 million and EBIT income of $4 million during the same periods in 2008. Our year-to-date 2009 EBIT loss primarily relates to the sale of the Porto Velho notes receivable during the second quarter of 2009. For the quarter ended September 30, 2009, our EBIT loss is primarily due to lower equity earnings from our investment in the Bolivia-to-Brazil Pipeline as a result of higher foreign taxes at the project. For the quarter ended September 30, 2008, our EBIT loss is primarily due to foreign exchanges losses on the Manaus and Rio Negro Brazilian reais-denominated receivables. This loss is more than offset by second quarter 2008 gains recognized on the sale of investments in Asia and Central America, resulting in year-to-date EBIT income for 2008.

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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 EBIT in our corporate activities for the periods ended September 30:

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(In millions)			
Change in litigation, environmental and other reserves	(19)	(7)	4	50
Foreign currency fluctuations on Euro-denominated debt		5	2	(1)
Gain on disposition of a portion of our telecommunications business				18
Other	(1)	(3)	(2)	8
Total EBIT	$ (20)	$ (5)	$ 4	$ 75

Litigation, Environmental, and Other Reserves. During the quarter and nine months ended September 30, 2009, we recorded mark-to-market losses of $3 million and gains of $22 million, respectively, associated with an indemnification in conjunction with the sale of a legacy ammonia facility based on fluctuations in ammonia prices. During the third quarter of 2009, we also recorded a $13 million charge for additional estimated environmental remediation costs related to a legacy non-operating chemical plant. In the first nine months of 2008, we recorded favorable adjustments related to resolving certain legacy litigation matters including $65 million related to the settlement of our Case Corporation indemnification dispute (see Item 1, Financial Statements, Note 9) and $32 million related to the settlement of certain class action matters. Partially offsetting these 2008 settlements were approximately $46 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 affect 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.

In addition to these matters, we anticipate that the net benefit cost related to our primary pension plan will increase in the future as a result of investment losses at the plan during 2008 and 2009. We do not anticipate making any contributions to our primary pension plan in 2010 as a result of these losses; however, the losses will be amortized into our future net benefit cost over a period of several years. For further discussion of our primary pension plan and related net benefit cost, see Item 1, Financial Statements, Note 10.

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 September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(In millions, except for rates)			
Income tax expense (benefit)	$35	$215	$(425)	$450
Effective tax rate	30%	32%	35%	34%

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 and, 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 within 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 during 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) finalized regulations to monitor and report GHG emissions on an annual basis and recently proposed new regulations to regulate GHGs under the Clean Air Act, which the EPA has indicated could be finalized as early as March 2010. 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 result in delays and have negative impacts 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, the costs of which would likely be material.

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 nine 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 took 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 obtaining a partner on our Ruby pipeline project.

During the third quarter of 2009, we entered into an agreement with several infrastructure funds managed by GIP, whereby it will invest up to $700 million in Ruby in three major tranches (i) a series of 7 percent loans totaling $405 million ($157 million of which has been borrowed under this loan commitment as of September 30, 2009), which will be converted into a preferred equity interest in Ruby upon satisfaction of certain conditions, (ii) $145 million which was contributed in October 2009 as a convertible preferred equity interest in Ruby and simultaneously exchanged for a convertible preferred equity interest in Cheyenne Plains with a 15 percent rate of return until the Ruby pipeline project is placed in-service, among other conditions and (iii) up to an additional $150 million of preferred equity contributions to be contributed to Ruby under the conditions that all FERC approvals for construction of the project are obtained and third party financing of approximately $1.4 billion is secured by Ruby by December 2010. 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 in Ruby 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, at the time of project completion, GIP would own a 50 percent equity interest in Ruby and all ownership in Cheyenne Plains would be transferred back to us. However, the GIP preferred equity interests in Ruby and Cheyenne Plains, along with amounts borrowed under GIP s loan commitment to Ruby, must be repaid in cash to GIP if (i) all FERC approvals for construction of the Ruby pipeline project are not obtained by December 2010, (ii) third party financing of approximately $1.4 billion is not secured by Ruby by December 2010 or (iii) the Ruby pipeline project is not placed in-service within 16 months of obtaining all FERC approvals. Additionally, if the financings are not completed, GIP has the option to convert its preferred interest in Cheyenne Plains to a 50 percent common interest in Cheyenne Plains. Our obligation to repay these amounts is secured by our equity interests in Ruby, Cheyenne Plains, and a portion of approximately 55 million common units we own in our MLP, El Paso Pipeline Partners, LP.

Available Liquidity and Liquidity Outlook. At September 30, 2009, we had approximately $2.4 billion of available liquidity, consisting of $1.0 billion of cash (exclusive of $90 million of cash at EPB and Ruby) and approximately $1.4 billion of capacity available to us under our various credit facilities (exclusive of $200 million available to EPB under its revolving credit facility and all project financing). In 2009, we have successfully generated additional liquidity of approximately $1.8 billion through various actions, including (i) $0.7 billion in proceeds through public debt offerings (approximately $500 million of El Paso notes and $250 million of TGP notes), (ii) two additional facilities for a combined $275 million in letter of credit capacity, (iii) $300 million of financings through our subsidiaries related to our Elba Island LNG facility and Elba Express pipeline project, (iv) $215 million in conjunction with contributing additional interests in CIG to our master limited partnership, and (v) the sale of approximately $300 million of non-core assets.

Our cash capital expenditures for the nine months ended September 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:

	Nine Months Ended September 30, 2009	2009 Remaining	Total
		(In billions)	
Pipelines			
Maintenance	$ 0.3	$ 0.1	$ 0.4
Growth[(1)]	1.0	0.6	1.6
Exploration and Production	0.7	0.3	1.0
Other	0.1		0.1
	$ 2.1	$ 1.0	$ 3.1

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

Our remaining debt maturities in 2009 are not material and in 2010 we have approximately $250 million of debt (excluding Ruby debt which we anticipate will convert into Ruby preferred equity) that will mature. We believe our actions taken over the last several months provide sufficient liquidity to meet our operating needs, fund our remaining 2009 capital program and position us well into 2010.

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. 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 Other Price Sensitivities. 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 September 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.

In November 2009, the borrowing base of our $1 billion revolving credit facility at our exploration and production subsidiary will be redetermined; however, 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 this facility to maintain our current borrowing base if necessary.

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. We have remaining planned pipeline expenditures of approximately $78 million to be spent through 2011. None of this amount is recoverable from insurance due to the losses not exceeding our self-retention levels for these events.

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Overview of Cash Flow Activities. During the first nine months of 2009, we generated positive operating cash flow of approximately $1.8 billion primarily as a result of cash provided by our pipeline and exploration and production operations. We also generated approximately $0.3 billion from asset sales and $1.0 billion from debt issuances in 2009 (exclusive of project financings), each of which are described in further detail above. We utilized a portion of these amounts to fund our maintenance and growth projects in our pipeline and exploration and production operations, refinance 2009 debt maturities of $1.3 billion, and pay common and preferred dividends, among other items. For the nine months ended September 30, 2009, our cash flows from continuing operations are summarized as follows:

	2009 (In billions)	
Cash Flow from Operations		
Operating activities		
Net loss	$	(0.8)
Ceiling test charges		2.1
Non-cash income adjustments		0.3
Change in assets and liabilities		0.2
Total cash flow from operations	$	1.8
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]		1.4
Net proceeds from issuance of noncontrolling interests		0.2
		1.6
Total other cash inflows	$	1.9
Cash Outflows		
Investing activities		
Capital expenditures	$	2.1
Financing activities		
Payments to retire long-term debt and other financing obligations		1.3
Dividends and other		0.2
		1.5
Total cash outflows	$	3.6

Net change in cash	$	0.1

(1) Includes approximately $0.2 billion of debt issued by Ruby for project related expenditures.

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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 September 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	$ 316	$ 82	$ 5	$ 11	$ 414
Liabilities	(218)	(314)	(68)	(129)	(729)
Total commodity-based derivatives	$ 98	$ (232)	$ (63)	$ (118)	$ (315)

The following is a reconciliation of our commodity-based derivatives for the nine months ended September 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]	(730)
Changes in fair value of contracts during the period	267
Premiums paid during the period	173
Net changes in contracts outstanding during the period	(290)
Fair value of contracts outstanding at September 30, 2009	$ (315)

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

Other Contractual Commitments and Purchase Obligations

During 2009, we entered into additional contracts to purchase and install approximately $0.4 billion of pipe primarily associated with the Ruby pipeline project and TGP s 300 Line expansion which are anticipated to be placed in service between 2010 and 2011.

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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					
September 30, 2009	$ 219	$ 61	$(158)	$ 383	$164
December 31, 2008	$ 682	$ 582	$(100)	$ 785	$103
Other commodity-based derivatives net liabilities					
September 30, 2009	$(534)	$(543)	$ (9)	$(525)	$ 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 September 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 concluded that our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) were effective as of September 30, 2009.

Changes in Internal Control over Financial Reporting

During the third quarter of 2009, we implemented a new financial accounting system and consolidated financial chart of accounts. The system implementation efforts were carefully planned and executed. Training sessions were administered to those employees who are impacted by the new system and chart of accounts, and system controls and functionality were reviewed and successfully tested prior and subsequent to implementation. Following evaluation, management believes that the new system has been successfully implemented. There were no other changes in our internal control over financial reporting during the third 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 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 entered into a Compliance Order on Consent and has paid the associated administrative penalty.

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 executed a Consent Decree with the DOJ and have paid 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. In January 2009, we filed with the FERC an application to abandon the facilities by sale which was granted. The sale of the facilities is scheduled to occur in November 2009.

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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. With the recent announcement of our decision to re-enter the midstream business, set forth below are some additional risk factors that may arise that are incremental to those risk factors set forth in our 2008 Annual Report on Form 10-K.

The midstream business may be subject to additional risks associated with fluctuations in energy commodity prices.

The midstream sector generally includes the gathering, transporting, processing, fractionating and storing of natural gas, NGLs and oil. The pricing for each of these hydrocarbon products has been volatile over time. In addition, the relative pricing between these hydrocarbon products has been volatile, which may affect fractionation spreads and the profitability of the business. Changes in prices and relative price levels may impact demand for hydrocarbon products, which in turn may impact production, demand and volumes of product for which we may provide services.

A decrease in demand for NGL products by the petrochemical, refining or heating industries could affect the profitability of our midstream business.

A decrease in demand for NGL products by the petrochemical, refining or heating industries, could adversely affect the profitability of our future midstream business. Various factors could impact the demand for NGL products, including general economic conditions, reduced demand by consumers for the end products made with NGL products, extended periods of ethane rejection, increased competition from petroleum-based products due to pricing differences, adverse weather conditions, availability of NGL processing and transportation capacity, government regulations affecting prices and production levels of natural gas, NGLs or the content of motor fuels.

We will face competition from third parties in our midstream businesses.

As we re-enter the midstream business, we will be competing with third parties to gather, transport, process, fractionate, store or handle hydrocarbons. Although we will attempt to leverage the synergies between our pipeline and exploration and production businesses, most of these third parties will have existing facilities and as a result initially have more scale and personnel than us. Therefore, there can be no assurances on how successful our re-entry into the midstream business will be.

We will face additional reserve and volumetric risk in our midstream business.

Although the revenues in our pipeline business are typically collected in the form of demand or reservation charges and are not dependent upon reserves or throughput levels, many transactions in the midstream business involve additional reserve and throughput risk. For example, oil and gas reserves committed to gathering and processing facilities may not be as large as expected, the life of the reserves may not be as long as expected or the producers may elect not to develop such reserves. We also cannot influence or control the production or the speed of development of the third-party natural gas we transport or process. The reserves committed will naturally decline overtime and our ability to attract new reserves in competition with third parties to replace these declining supplies is uncertain. Furthermore, the rate at which production from these reserves decline may be greater than we anticipate. As a result, we may face additional reserve and throughput risk in our midstream business than we typically experience in our pipeline business.

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

None.

Item 3. Defaults Upon Senior Securities

None.

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

None.

Item 5. Other Information

None.

Item 6. Exhibits

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: November 6, 2009	/s/ D. Mark Leland D. Mark Leland Executive Vice President and Chief Financial Officer (Principal Financial Officer)
Date: November 6, 2009	/s/ John R. Sult John R. Sult Senior Vice President and Controller (Principal Accounting Officer)

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EL PASO CORPORATION
EXHIBIT INDEX

Each exhibit identified below is 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
*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.INS	XBRL Instance Document.
*101.SCH	XBRL Schema Document.
*101.CAL	XBRL Calculation Linkbase Document.
*101.DEF	XBRL Definition Linkbase Document.
*101.LAB	XBRL Labels Linkbase Document.
*101.PRE	XBRL Presentation Linkbase Document.