EL PASO CORP/DE
Form 10-Q
November 08, 2010

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, 2010

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

Telephone Number: (713) 420-2600
Internet Website: www.elpaso.com

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

Indicate by check mark whether the registrant 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.:

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 1, 2010: 704,142,559

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

/d = per day

Bbl = barrels

BBtu = billion British thermal units

Bcf = billion cubic feet

GW = gigawatts

GWh = gigawatt hours

LNG = liquefied natural gas

MBbls = thousand barrels

Mcf = thousand cubic feet

Mcfe = thousand cubic feet of natural gas equivalents

MMBbls = million barrels

MMBtu = million British thermal units

MMcf = million cubic feet

MMcfe = million cubic feet of natural gas equivalents

NGL = natural gas liquids

TBtu = trillion British thermal units

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

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

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,	
	2010	**2009**	**2010**	**2009**
Operating revenues	$ 1,213	$ 981	$ 3,632	$ 3,438
Operating expenses				
Cost of products and services	57	45	163	158
Operation and maintenance	327	346	911	910
Ceiling test charges	14	5	16	2,085
Depreciation, depletion and amortization	239	200	699	653
Taxes, other than income taxes	58	56	181	181
	695	652	1,970	3,987
Operating income (loss)	518	329	1,662	(549)
Earnings from unconsolidated affiliates	28	11	167	42
Other income (expense)	(33)	33	84	71
Interest and debt expense	(255)	(256)	(782)	(764)
Income (loss) before income taxes	258	117	1,131	(1,200)
Income tax (benefit) expense	75	35	343	(425)
Net income (loss)	183	82	788	(775)
Net income attributable to noncontrolling interests	(41)	(15)	(101)	(38)
Net income (loss) attributable to El Paso Corporation	142	67	687	(813)
Preferred stock dividends of El Paso Corporation	9	9	28	28
Net income (loss) attributable to El Paso Corporation s common stockholders	$ 133	$ 58	$ 659	$ (841)
Basic earnings (loss) per common share				
Net income (loss) attributable to El Paso Corporation s common stockholders	$ 0.19	$ 0.08	$ 0.95	$ (1.21)
Diluted earnings (loss) per common share				
Net income (loss) attributable to El Paso Corporation s common stockholders	$ 0.19	$ 0.08	$ 0.90	$ (1.21)
Dividends declared per El Paso Corporation s common share	$ 0.01	$ 0.05	$ 0.03	$ 0.15

See accompanying notes.

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

	September 30, 2010	December 31, 2009
ASSETS		
Current assets		
Cash and cash equivalents (includes $27 in 2010 and $149 in 2009 held by variable interest entities)	$ 809	$ 635
Accounts and notes receivable		
Customer, net of allowance of $5 in 2010 and $8 in 2009	293	346
Affiliates	5	92
Other	138	115
Materials and supplies	167	175
Assets from price risk management activities	324	221
Deferred income taxes	142	298
Other	91	126
Total current assets	1,969	2,008
Property, plant and equipment, at cost		
Pipelines (includes $2,409 in 2010 and $1,179 in 2009 held by variable interest entities)	21,376	19,722
Natural gas and oil properties, at full cost	21,544	20,846
Other	409	314
	43,329	40,882
Less accumulated depreciation, depletion and amortization	23,323	22,987
Total property, plant and equipment, net	20,006	17,895
Other assets		
Investments in unconsolidated affiliates	1,538	1,718
Assets from price risk management activities	131	123
Other	863	761
	2,532	2,602
Total assets	$ 24,507	$ 22,505

See accompanying notes.

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

	September 30, 2010	December 31, 2009
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 514	$ 459
Affiliates	9	7
Other	399	424
Short-term financing obligations, including current maturities	637	477
Liabilities from price risk management activities	181	269
Asset retirement obligations	110	158
Accrued interest	244	208
Other	620	684
Total current liabilities	2,714	2,686
Long-term financing obligations, less current maturities	13,134	13,391
Other		
Liabilities from price risk management activities	454	462
Deferred income taxes	507	339
Other	1,416	1,491
	2,377	2,292
Commitments and contingencies (Note 10)		
Preferred stock of subsidiaries	681	145
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 719,513,700 shares in 2010 and 716,041,302 shares in 2009	2,159	2,148
Additional paid-in capital	4,484	4,501
Accumulated deficit	(2,505)	(3,192)
Accumulated other comprehensive loss	(749)	(718)
	(290)	(283)

Treasury stock (at cost); 15,403,572 shares in 2010 and 14,761,654 shares in 2009				
Total El Paso Corporation stockholders equity		3,849		3,206
Noncontrolling interests		1,752		785
Total equity		5,601		3,991
Total liabilities and equity	$	24,507	$	22,505

See accompanying notes.

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

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Cash flows from operating activities		
Net income (loss)	$ 788	$ (775)
Adjustments to reconcile net income (loss) to net cash from operating activities		
Depreciation, depletion and amortization	699	653
Ceiling test charges	16	2,085
Deferred income tax expense (benefit)	339	(448)
Earnings from unconsolidated affiliates, adjusted for cash distributions	(115)	17
Other non-cash income items	70	53
Asset and liability changes	(293)	196
Net cash provided by operating activities	1,504	1,781
Cash flows from investing activities		
Capital expenditures	(2,733)	(2,081)
Cash paid for acquisitions, net of cash acquired	(33)	(39)
Net proceeds from the sale of assets and investments	332	303
Other	22	15
Net cash used in investing activities	(2,412)	(1,802)
Cash flows from financing activities		
Net proceeds from issuance of long-term debt	1,399	1,369
Payments to retire long-term debt and other financing obligations	(1,273)	(1,290)
Net proceeds from issuance of noncontrolling interests	956	212
Net proceeds from issuance of preferred stock of subsidiary	120	
Dividends paid	(49)	(133)
Distributions to noncontrolling interest holders	(64)	(33)
Distributions to holders of preferred stock of subsidiary	(15)	
Other	8	(7)
Net cash provided by financing activities	1,082	118
Change in cash and cash equivalents	174	97
Cash and cash equivalents		
Beginning of period	635	1,024
End of period	$ 809	$ 1,121

See accompanying notes.

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

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
El Paso Corporation stockholders equity:		
Preferred stock:		
Balance at beginning and end of period	$ 750	$ 750
Common stock:		
Balance at beginning of period	2,148	2,138
Other, net	11	10
Balance at end of period	2,159	2,148
Additional paid-in capital:		
Balance at beginning of period	4,501	4,612
Dividends	(49)	(133)
Other, including stock-based compensation	32	26
Balance at end of period	4,484	4,505
Accumulated deficit:		
Balance at beginning of period	(3,192)	(2,653)
Net income (loss) attributable to El Paso Corporation	687	(813)
Balance at end of period	(2,505)	(3,466)
Accumulated other comprehensive loss:		
Balance at beginning of period	(718)	(532)
Other comprehensive loss	(31)	(177)
Balance at end of period	(749)	(709)
Treasury stock, at cost:		
Balance at beginning of period	(283)	(280)
Stock-based and other compensation	(7)	(2)
Balance at end of period	(290)	(282)
Total El Paso Corporation stockholders equity at end of period	3,849	2,946
Noncontrolling interests:		
Balance at beginning of period	785	561
Distributions paid to noncontrolling interests	(64)	(33)

Issuances of noncontrolling interests	956	212
Net income attributable to noncontrolling interests (Note 12)	75	38
Balance at end of period	1,752	778
Total equity at end of period	$ 5,601	$ 3,724

See accompanying notes.

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

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2010	**2009**	**2010**	**2009**
Net income (loss)	$ 183	$ 82	$ 788	$ (775)
Pension and postretirement obligations:				
Reclassification of net actuarial losses during period (net of income taxes of $6 and $18 in 2010 and $3 and $11 in 2009)	11	7	35	21
Cash flow hedging activities:				
Unrealized mark-to-market gains (losses) arising during period (net of income taxes of $20 and $45 in 2010 and $5 and $3 in 2009)	(31)	(5)	(71)	5
Reclassification adjustments for changes in initial value to the settlement date (net of income taxes of $1 and $3 in 2010 and $34 and $114 in 2009)	1	(61)	5	(203)
Other comprehensive loss	(19)	(59)	(31)	(177)
Comprehensive income (loss)	164	23	757	(952)
Comprehensive income attributable to noncontrolling interests	(41)	(15)	(101)	(38)
Comprehensive income (loss) attributable to El Paso Corporation	$ 123	$ 8	$ 656	$ (990)

See accompanying notes.

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

1. Basis of Presentation and Significant Accounting Policies

Basis of Presentation

We prepared this Quarterly Report on Form 10-Q under the rules and regulations of the United States Securities and Exchange Commission (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 report along with our 2009 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, 2010, and for the quarters and nine months ended September 30, 2010 and 2009, are unaudited. We derived the condensed consolidated balance sheet as of December 31, 2009, from the audited balance sheet filed in our 2009 Annual Report on Form 10-K. In our opinion, we have made adjustments, all of which are of a normal, recurring nature to fairly present our interim period results. Due to the seasonal nature of our businesses, information for interim periods may not be indicative of our operating results for the entire year.

Significant Accounting Policies

The following is an update of our significant accounting policies and accounting pronouncements issued and adopted during the nine months ended September 30, 2010.

Transfers of Financial Assets. On January 1, 2010, we adopted an accounting standards update for financial asset transfers. Among other items, this update requires the sale of an entire financial asset or a proportionate interest in a financial asset in order to qualify for sale accounting. These changes were effective for sales of financial assets occurring on or after January 1, 2010. In January 2010, we terminated our prior accounts receivable sales programs under which we previously sold senior interests in certain of our pipeline accounts receivable to a third party financial institution (through wholly-owned special purpose entities). As a result, the adoption of this accounting standards update did not have a material impact on our financial statements. Upon termination of the prior accounts receivable sales programs, we entered into new accounts receivable sales programs under which we sell certain of our pipeline accounts receivable in their entirety to the third party financial institution (through wholly-owned special purpose entities). The transfer of these receivables qualifies for sale accounting under the provisions of this accounting standards update. We present the cash flows related to the prior and new accounts receivable sales programs as operating cash flows in our statements of cash flows. For further information, see Note 14.

Variable Interest Entities. On January 1, 2010, we adopted an accounting standards update for variable interest entities that revise how companies determine the primary beneficiary of these entities, among other changes. Companies are now required to use a qualitative approach based on their responsibilities and power over the entities operations, rather than a quantitative approach in determining the primary beneficiary as previously required. Additionally, the primary beneficiary is required to retrospectively present qualifying assets and liabilities of variable interest entities separately on the balance sheet. Other than the required change in presentation on our balance sheet, the adoption of this accounting standards update did not have a material impact on our financial statements. For a further discussion of our involvement with variable interest entities, see Note 14.

2. Divestitures

During 2010, we (i) completed the sale of certain of our interests in Mexican pipeline and compression assets for approximately $300 million and recorded a pretax gain of approximately $80 million in earnings from unconsolidated affiliates and (ii) sold non-core natural gas producing properties located in our Gulf Coast division for approximately $22 million. During 2009, we (i) sold our investment in the Argentina-to-Chile pipeline to our partners in the project for approximately $32 million, (ii) sold non-core natural gas producing properties located in our Central and Western divisions for approximately $95 million, and (iii) sold 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. In the second quarter of 2009, we sold the notes, including accrued interest, to a third party financial institution for $57 million and recorded a loss of approximately $22 million.

3. Ceiling Test Charges

We are required to conduct quarterly impairment tests of our capitalized costs in each of our full cost pools. During the quarters and nine months ended September 30, 2010 and 2009, we recorded the following ceiling test charges:

	Quarters Ended September 30, 2010	Quarters Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
	(In millions)			
Full cost pool:				
U.S.	$	$	$	$ 2,031
Brazil				28
Egypt	14	5	16	26
Total	$ 14	$ 5	$ 16	$ 2,085

During 2009, the calculation of these charges was based on spot commodity prices at the end of each quarter, as required at that time. As a result of our adoption of the SEC s final rule on the Modernization of Oil and Gas Reporting, effective December 31, 2009, we began using a 12-month average price (calculated as the unweighted arithmetic average of the price on the first day of each month within the 12-month period prior to the end of the reporting period) when performing these ceiling tests. In calculating our ceiling test charges, we are also 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.

4. Other Income and Other Expense

The following are the components of other income and other expense for the quarters and nine months ended September 30:

	Quarters Ended September 30, 2010	Quarters Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
	(In millions)			
Other Income				
Allowance for equity funds used during construction	$ 55	$ 18	$ 156	$ 60
Other	19	15	36	36
Total	74	33	192	96
Other Expenses				
Loss on debt extinguishment (Note 9)	$ 104	$	$ 104	$
Other	3		4	25
Total	107		108	25
Other income (expense)	$ (33)	$ 33	$ 84	$ 71

Allowance for Equity Funds Used During Construction (AFUDC). As allowed by the Federal Energy Regulatory Commission (FERC), we capitalize as AFUDC a pre-tax carrying cost on equity funds related to the construction of long-lived assets in our FERC regulated business and reflect this amount as an increase in the cost of the asset on our balance sheet. We calculate this amount using the most recent FERC approved equity rate of return. These amounts are recovered over the depreciable lives of the long-lived assets to which they relate.

Loss on Debt Extinguishment. In September 2010, we exchanged approximately $348 million of our 12.00% Senior Notes due 2013 for cash and 6.50% Senior Notes due 2020. In conjunction with the transaction, we recorded a loss of $104 million consisting of $77 million of cash consideration paid to the holders of the 12% Senior Notes, and $27 million to write-off unamortized discount and debt issue costs.

5. Income Taxes

Income taxes for the quarters and nine months ended September 30 were as follows:

	Quarters Ended September 30, 2010	Quarters Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
	(In millions, except rates)			
Income tax (benefit) expense	$ 75	$ 35	$ 343	$ (425)
Effective tax rate	29%	30%	30%	35%

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, which are recorded in the period that the item occurs. Changes in tax laws or rates are recorded in the period of enactment. Our effective tax rate is affected by items such as income attributable to nontaxable noncontrolling interests, 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.

For the quarter and nine months ended September 30, 2010, our effective tax rate was impacted by income attributable to nontaxable noncontrolling interests and the liquidation of certain foreign entities. Also impacting our effective tax rate for the nine months ended September 30, 2010 was the sale of certain of our interests in Mexican pipeline and compression assets. Partially offsetting these items was $18 million of additional deferred income tax expense recorded in the first quarter from healthcare legislation enacted in March 2010 which reduces the tax deduction for retiree prescription drug expenses to the extent they are reimbursed under the Medicare subsidy program. For the nine months ended September 30, 2009, our effective tax rate was relatively consistent with the statutory rate and the customary relationship between our pretax accounting income and income tax expense. During the third quarter of 2009, our effective tax rate was primarily impacted by foreign income taxed at different rates.

6. Earnings Per Share

We calculated basic and diluted earnings (loss) per common share as follows for the quarters and nine months ended September 30:

Quarters Ended September 30,

	2010 Basic	2010 Diluted	2009 Basic	2009 Diluted
	(In millions, except per share amounts)			
Net income attributable to El Paso Corporation	$ 142	$ 142	$ 67	$ 67
Preferred stock dividends of El Paso Corporation	(9)		(9)	(9)
Net income attributable to El Paso Corporation s common stockholders	$ 133	$ 142	$ 58	$ 58
Weighted average common shares outstanding	699	699	696	696
Effect of dilutive securities:				
Options and restricted stock		5		4
Convertible preferred stock		58		
Weighted average common shares outstanding and dilutive securities	699	762	696	700

Basic and diluted earnings per common share:				
Net income attributable to El Paso Corporation s common stockholders	$ 0.19	$ 0.19	$ 0.08	$ 0.08

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Nine Months Ended September 30,

	2010		2009	
	Basic	Diluted	Basic	Diluted
	(In millions, except per share amounts)			
Net income (loss) attributable to El Paso Corporation	$ 687	$ 687	$ (813)	$ (813)
Preferred stock dividends of El Paso Corporation	(28)		(28)	(28)
Net income (loss) attributable to El Paso Corporation s common stockholders	$ 659	$ 687	$ (841)	$ (841)
Weighted average common shares outstanding	698	698	695	695
Effect of dilutive securities:				
Options and restricted stock		5		
Convertible preferred stock		58		
Weighted average common shares outstanding and dilutive securities	698	761	695	695
Basic and diluted earnings (loss) per common share:				
Net income (loss) attributable to El Paso Corporation s common stockholders	$ 0.95	$ 0.90	$ (1.21)	$ (1.21)

We exclude potentially dilutive securities from the determination of diluted earnings per share (as well as their related income statement impacts) when their impact on net income attributable to El Paso Corporation per common share is antidilutive. Potentially dilutive securities consist of employee stock options, restricted stock, convertible preferred stock and trust preferred securities. For the quarter and nine months ended September 30, 2010, and the quarter ended September 30, 2009, certain of our employee stock options were antidilutive. Additionally, our trust preferred securities were antidilutive in all periods presented and our convertible preferred stock was antidilutive for the quarter ended September 30, 2009. 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.

7. Fair Value of Financial Instruments

On January 1, 2009, we adopted an accounting standard update 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 and recorded a $34 million gain (net of $18 million of taxes), or $0.05 per share, in 2009 as a result of adopting this new accounting update.

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. The fair value of an instrument depends 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 the instrument. 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 fair value. 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 is described below:

Level 1 instruments   fair values are based on quoted prices for the instruments in actively traded markets.

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).

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.

During the quarter and nine months ended September 30, 2010, there have been no changes to the types of instruments or the levels in which they are classified. For a further description of these levels and our corresponding instruments classified by level, see our 2009 Annual Report on Form 10-K.

Listed below are the fair values of our financial instruments that are recorded at fair value classified in each level at September 30, 2010 and December 31, 2009:

	September 30, 2010				December 31, 2009			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(In millions)							
Assets								
Commodity-based derivatives								
Production-related natural gas and oil derivatives	$	$ 381	$	$ 381	$	$ 169	$	$ 169
Other natural gas derivatives		32	17	49		106	21	127
Power-related derivatives			14	14			37	37
Interest rate derivatives		11		11		11		11
Marketable securities invested in non-qualified compensation plans	21			21	20			20
Total assets	21	424	31	476	20	286	58	364
Liabilities								
Commodity-based derivatives								
Production-related natural gas and oil derivatives		(13)		(13)		(42)		(42)
Other natural gas derivatives		(61)	(100)	(161)		(153)	(133)	(286)
Power-related derivatives			(356)	(356)			(386)	(386)
Interest rate derivatives		(105)		(105)		(17)		(17)
Other			(13)	(13)			(31)	(31)
Total liabilities		(179)	(469)	(648)		(212)	(550)	(762)
Total	$ 21	$ 245	$ (438)	$ (172)	$ 20	$ 74	$ (492)	$ (398)

On certain derivative contracts recorded as assets in the table above, 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 and determined that our exposure is primarily related to our production-related derivatives and is limited to nine 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 quarters and nine months ended September 30, 2010:

	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
	(In millions)				
Quarter Ended September 30, 2010					
Assets	$ 43	$ (11)	$	$ (1)	$ 31
Liabilities	(494)	(3)	(1)	29	(469)
Total	$ (451)	$ (14)	$ (1)	$ 28	$ (438)
Nine Months Ended September 30, 2010					
Assets	$ 58	$ (25)	$	$ (2)	$ 31
Liabilities	(550)	(14)	(2)	97	(469)
Total	$ (492)	$ (39)	$ (2)	$ 95	$ (438)

(1) Includes approximately $12 million and $38 million of net losses that had not been realized through settlements for the quarter and nine months ended September 30, 2010. These losses are primarily based on additional market information on these contracts.

(2) Includes $1 million and $2 million of net losses that had not been realized through settlements for the quarter and nine months ended September 30, 2010.

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

	September 30, 2010		December 31, 2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Financing obligations	$ 13,771	$ 14,717	$ 13,868	$ 14,151
Marketable securities invested in non-qualified compensation plans	21	21	20	20
Commodity-based derivatives	(86)	(86)	(381)	(381)
Interest rate derivatives	(94)	(94)	(6)	(6)
Other derivatives	(13)	(13)	(31)	(31)
Other	1	1	17	17

As of September 30, 2010 and December 31, 2009, the carrying amounts of cash and cash equivalents, short-term borrowings, and accounts receivable and payable 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 the nature of their interest rates and our assessment of the 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.

8. 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 and (ii) interest rate exposure on our long-term debt. We also hold other derivatives not intended to hedge these exposures. When we enter into derivative contracts, we may designate the derivative as either a cash flow hedge or a fair value hedge. 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. For a detailed description on how our derivatives are reflected and accounted for on our balance sheet and statements of income, comprehensive income and cash flows, see our 2009 Annual Report on Form 10-K.

Balance Sheet Presentation. The following table presents the fair value of our derivatives on a gross basis by contract type as presented on our balance sheets. We have not netted these contracts for counterparties where we have a legal right of offset or for cash collateral associated with these derivatives. At September 30, 2010 and December 31, 2009, cash collateral held was not material.

	Fair Value of Derivative Assets		Fair Value of Derivative Liabilities	
	September 30, 2010	December 31, 2009	September 30, 2010	December 31, 2009
	(In millions)			
Derivatives Designated as Hedges:				
Interest rate derivatives				
Cash flow hedges	$	$ 1	$ (105)	$ (17)
Fair value hedges	11	10		
Total derivatives designated as hedges	11	11	(105)	(17)
Derivatives not Designated as Hedges:				
Commodity-based derivatives				
Production-related	437	239	(69)	(112)

Other natural gas	192	519	(304)	(678)
Power-related	46	57	(388)	(406)
Total derivatives not designated as hedges	675	815	(761)	(1,196)
Impact of master netting arrangements	(231)	(482)	231	482
Total assets (liabilities) from price risk management activities	455	344	(635)	(731)
Other derivatives			(13)	(31)
Total derivatives	$ 455	$ 344	$ (648)	$ (762)

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; however, we are subject to commodity price risks on a portion of our forecasted production. As of September 30, 2010 and December 31, 2009, we have production-related derivatives on 272 Tbtu and 313 Tbtu of natural gas and 6,484 MBbl and 4,016 MBbl of oil.

Other Commodity-Based Derivatives. In our Marketing segment, we have long-term natural gas and power derivative contracts that include forwards, swaps and options that we either intend to manage until their expiration or liquidate to the extent it is economical and prudent. None of these derivatives are designated as accounting hedges. As of September 30, 2010 and December 31, 2009, these 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 Pennsylvania-New Jersey-Maryland (PJM) eastern region with the PJM west hub on approximately 3,700 GWh from 2010 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 to economically mitigate our exposure to commodity price changes on substantially all of these volumes as well as 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. As of September 30, 2010 and December 31, 2009, we had interest rate swaps, which are designated as cash flow hedges that we used to convert the interest rate on approximately $1.3 billion and $169 million of debt from a floating LIBOR interest rate to a fixed interest rate. Approximately $1.1 billion of the debt hedged as of September 30, 2010, relates to debt commitments associated with our Ruby pipeline project. These swaps begin accruing interest on July 1, 2011 and have termination dates ranging from June 2013 to June 2017 which correspond to the estimated principal outstanding on the Ruby debt over the term of these swaps. For a further discussion of our Ruby financing, see Note 9.

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. We record changes in the fair value of these derivatives in interest expense. As of September 30, 2010 and December 31, 2009, our hedges converted the interest rate on approximately $218 million of debt from a fixed rate to a variable rate of LIBOR plus 4.18%. We also had interest rate swaps with a notional amount of $222 million for which changes in the fair value of these swaps were substantially eliminated by offsetting swaps contracts.

During the second quarter of 2009, our Euro-denominated debt matured and we settled all of our related cross-currency swaps, which were designated as fair value hedges of this debt.

Statements of Income and Comprehensive Income. Listed below are the impacts of our commodity-based and interest rate derivatives to our income statement and statement of comprehensive income for the quarters and nine months ended September 30:

	2010				**2009**			
	Operating Revenues	**Interest Expense**	**Other Income**	**Other Comprehensive Income (Loss)**	**Operating Revenues**	**Interest Expense**	**Other Income**	**Other Comprehensive Income (Loss)**
	(In millions)							
Quarters ended September 30,								
Production-related derivatives[1]	$ 184	$	$	$ 2	$ 87	$	$	$ (95)
Other natural gas and power derivatives not designated as hedges	(14)				(20)			
Total interest rate derivatives[2]		4		(43)		2		
Total price risk management activities[3]	$ 170	$ 4	$	$ (41)	$ 67	$ 2	$	$ (95)
Nine months ended September 30,								
Production-related derivatives[1]	$ 468	$	$	$ 8	$ 536	$	$	$ (322)
Other natural gas and power derivatives not designated as hedges	(40)				53			
Total interest rate derivatives[2]		13		(89)		9	(26)	8
Total price risk management activities[3]	$ 428	$ 13	$	$ (81)	$ 589	$ 9	$ (26)	$ (314)

(1) We reclassified $2 million and $8 million of accumulated other comprehensive loss for the quarter and nine months ended

September 30, 2010 and $95 million and $322 million of accumulated other comprehensive income for the quarter and nine months ended September 30, 2009 into operating revenues on derivatives for which we removed the cash-flow hedging designation in 2008. Approximately $12 million of our accumulated other comprehensive loss will be reclassified to operating revenues over the next twelve months.

(2) Included in interest expense is $1 million and $5 million representing the amount of accumulated other comprehensive income that was reclassified into income related to these interest rate derivatives designated as cash flow hedges for the quarter and nine

months ended September 30, 2010. We anticipate that $15 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, 2010.

(3) We also had approximately $1 million and $3 million of losses for the quarters ended September 30, 2010 and 2009 and $2 million of losses and $22 million of gains for the nine months ended September 30, 2010 and 2009 recognized in operating expenses related to other derivative instruments not associated with our price risk management activities.

9. Debt, Other Financing Obligations and Other Credit Facilities

	September 30, 2010	December 31, 2009
	(In millions)	
Short-term financing obligations, including current maturities	$ 637	$ 477
Long-term financing obligations	13,134	13,391
Total	$ 13,771	$ 13,868

Changes in Financing Obligations. During the nine months ended September 30, 2010, we had the following changes in our financing obligations:

Company	Interest Rate	Book Value Increase (Decrease)	Cash Received (Paid)
		(In millions)	
Issuances			
Ruby Holding Company loan commitment(1)	13.00%	188	187
Ruby Pipeline, L.L.C. credit facility	variable	362	308
El Paso notes due 2020(2)	6.50%	348	
El Paso Pipeline Partners Operating Company, L.L.C. notes due 2020	6.50%	535	528
El Paso revolving credit facility	variable	193	193
El Paso Pipeline Partners Operating Company, L.L.C. revolving credit facility	variable	114	114
Other	variable	69	69
Increases through September 30, 2010		$ 1,809	$ 1,399
Repayments, repurchases, and other			
El Paso Exploration and Production Company revolving credit facility	variable	$ (469)	$ (469)
El Paso revolving credit facility	variable	(393)	(393)
El Paso Pipeline Partners Operating Company, L.L.C. revolving credit facility	variable	(114)	(114)
El Paso notes due 2010	7.75% and 7.80%	(149)	(149)
El Paso notes due 2013(2)	12.00%	(323)	(77)
Ruby Holding Company loan commitment(1)	13.00%	(405)	
Other	various	(53)	(71)
Decreases through September 30, 2010		$ (1,906)	$ (1,273)

(1) Initial interest rate of 7.00%

increased to 13.00% effective April 1, 2010. Loan commitment was converted to Ruby convertible preferred equity interest in August 2010.

(2) In the third quarter of 2010, we exchanged debt with a principal value of approximately $348 million which, net of discounts, had a carrying value of $323 million for new notes and cash. We recorded a loss on debt extinguishment in conjunction with this transaction as further discussed in Note 4.

Credit Facilities. We have various credit facilities in place which allow us to borrow funds or issue letters of credit. As of September 30, 2010, we had total available capacity of approximately $2.2 billion under these facilities (not including capacity available under the El Paso Pipeline Partners, L.P. (EPB) $750 million revolving credit facility, our Ruby project financing and other project financings).

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. The revolving credit facilities of our exploration and production subsidiary are collateralized by certain of our natural gas and oil properties. These facilities include a $1.0 billion revolving credit facility with a borrowing base subject to revaluation on a semi-annual basis. There have been no significant changes to our restrictive covenants from those disclosed in our 2009 Annual Report on Form 10-K, and as of September 30, 2010, we were in compliance with all of our debt covenants.

Letters of Credit. We enter into letters of credit and surety bonds 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, 2010, we had total outstanding letters of credit and surety bonds issued under all of our facilities of approximately $0.9

billion. Included in this amount is approximately $0.5 billion of letters of credit securing our recorded obligations related to price risk management activities.

Ruby Pipeline Financing. In May 2010, we entered into a seven-year amortizing $1.5 billion credit facility for our Ruby pipeline project that requires principal payments at various dates through June 2017. During the third quarter of 2010, we borrowed $362 million under this credit facility. In October 2010, we made an additional draw of approximately $240 million on the facility. Our initial interest rate on amounts borrowed is LIBOR plus 3 percent which increases to LIBOR plus 3.25 percent for years three and four, and to LIBOR plus 3.75 percent for years five through seven assuming we refinance $700 million of the facility by the end of year four. If we do not refinance $700 million by the end of year four, the rate will be LIBOR plus 4.25 percent for years five through seven. In conjunction with entering into this facility, we entered into interest rate swaps that begin in July 2011 and convert the floating LIBOR interest rate to fixed interest rates on approximately $1.1 billion of total borrowings under this agreement. For a further discussion of these swaps, see Note 8.

We have provided a contingent completion and cost-overrun guarantee to Ruby lenders; however, upon the Ruby pipeline project becoming operational and making certain permitting representations, the project financing will become non-recourse to us. Pursuant to the cost overrun guarantee to the Ruby lenders, we are required to post letters of credit for any forecasted cost overruns on the project approved by the lender s independent engineer. In this regard, we have posted $245 million in letters of credit to cover the anticipated cost overruns. If additional costs overruns are forecasted and approved by the lender s engineer in subsequent months, then additional letters of credit will be required to be issued pursuant to the Ruby financing agreements.

10. 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 defined benefit pension plan to a cash balance pension plan. The trial court has dismissed all of the claims. The dismissal of the case has been appealed.

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 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 are currently obligated to pay the amounts above the cap. In addition, we are obligated to pay damages incurred by retirees prior to the court s ruling that the benefits were not subject to the cap pursuant to a claims procedure approved by the court. We have been engaged in settlement discussions with the plaintiffs. However, if we are unable to reach a mutually agreeable settlement, we intend to pursue appellate options. 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. While some of the cases have been settled or dismissed, several of the cases are in various stages of pre-trial or appellate proceedings as further described in our 2009 Annual Report on Form 10-K. In September 2010, the dismissal of the Missouri state court lawsuit entitled *Missouri Public Service v. El Paso Corporation, et al* was upheld on appeal and is now a final judgment. Our costs and legal exposure related to the remaining outstanding 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 seeking 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. Eighty-seven of the cases have been settled or dismissed, with all of the settlements being substantially funded by insurance. Of our twelve remaining lawsuits, it is likely that our insurers will assert denial of coverage on the nine most-recently filed. Our costs and legal exposure related to the remaining lawsuits are not currently determinable.

In addition to the above proceedings, we and our subsidiaries and affiliates are named defendants in numerous legal 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, 2010, we had approximately $49 million accrued, which has not been reduced by $2 million of related insurance receivables, for our outstanding legal proceedings.

Rates and Regulatory Matters

El Paso Natural Gas Company (EPNG) Rate Case. In April 2010, the FERC approved an uncontested partial offer of settlement which increased EPNG s base tariff rates, effective January 1, 2009. As part of the settlement, EPNG made an initial refund to its customers in April 2010, and paid the remaining refunds in August 2010. The settlement resolved all but four issues in the proceeding. A hearing on the remaining issues was completed in June 2010 and the outcome is not currently determinable. We believe our accruals established for this matter are adequate.

In September 2010, EPNG filed a new rate case with the FERC proposing an increase in its base tariff rates as permitted under the settlement of the previous rate case. In October 2010, the FERC issued an order accepting and suspending the effective date of the proposed rates to April 1, 2011, subject to refund, the outcome of a hearing and other proceedings. At this time, the outcome of this matter is not currently determinable.

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 of the disposal or release of specified substances at current and former operating sites. At September 30, 2010, we had accrued approximately $177 million for environmental matters, which has not been reduced by $20 million for amounts to be paid directly under government sponsored programs or through contractual arrangements with third parties. Our accrual includes approximately $173 million for expected remediation costs and associated onsite, offsite and groundwater technical studies and approximately $4 million for related environmental legal costs. Of the $177 million accrual, $12 million was reserved for facilities we currently operate and $165 million was reserved for non-operating sites (facilities that are shut down or have been sold) and Superfund sites.

Our estimates of potential liability range from approximately $177 million to approximately $374 million. Our recorded environmental liabilities reflect our current estimates of amounts we will expend on remediation projects in various stages of completion. 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, 2010	
Sites	**Expected**	**High**
	(In millions)	
Operating	$ 12	$ 20
Non-operating	149	315
Superfund	16	39
Total	$ 177	$ 374

Below is a reconciliation of our accrued liability from January 1, 2010 to September 30, 2010 (in millions):

Balance as of January 1, 2010	$ 189
Additions/adjustments for remediation activities	17
Payments for remediation activities	(29)
Balance as of September 30, 2010	$ 177

Superfund Matters. Included in our recorded environmental liabilities are projects where we have received notice that we have been designated or could be designated, as a Potentially Responsible Party (PRP) under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), commonly known as Superfund, or state equivalents for 31 active sites. Liability under the federal CERCLA statute may be joint and several, meaning that we could be required to pay in excess of our pro rata share of remediation costs. We consider the financial strength of other PRPs in estimating our liabilities. Accruals for these issues are included in the previously indicated estimates for Superfund sites.

For the remainder of 2010, we estimate that our total remediation expenditures will be approximately $16 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 $25 million in the aggregate for the remainder of 2010 through 2014. Included in this amount is approximately $20 million to be expended from 2010 to 2013 associated with the impact of the Environmental Protection Agency (EPA) rule on emissions of hazardous air pollutants from reciprocating internal combustion engines which was finalized in August 2010. Our engines that are subject to the regulations have to be in compliance by October 2013.

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. We also periodically provide indemnification arrangements related to assets or businesses we have sold for which our potential exposure can range from a specified amount to an unlimited dollar amount, depending on the nature of the claim and the particular transaction. For a further discussion, see our 2009 Annual Report on Form 10-K. For those arrangements with a specified dollar amount, we have a maximum stated value of approximately $0.8 billion, primarily related 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 9. 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, 2010, we have recorded obligations of $19 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, Purchase Obligations and Other Matters. In 2009, the FERC approved an amendment to the 1995 FERC settlement with Tennessee Gas Pipeline Company (TGP) that provides for interim refunds over a three year period of approximately $157 million for 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. As of September 30, 2010, TGP has refunded approximately $49 million to their customers.

11. Retirement Benefits

Net Benefit Cost. The components of net benefit cost for our pension and postretirement benefit plans for the quarters and nine months 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	
	2010	2009	2010	2009	2010	2009	2010	2009
	(In millions)							
Service cost	$ 5	$ 6	$	$	$ 14	$ 14	$	$
Interest cost	29	31	8	10	86	91	25	29
Expected return on plan assets	(39)	(43)	(3)	(3)	(118)	(129)	(10)	(9)
Amortization of net actuarial loss (gain)	18	12			55	34	(2)	
Amortization of prior service cost (credit)		(1)	(1)	(1)	1	(1)	(1)	(1)
Net benefit cost	$ 13	$ 5	$ 4	$ 6	$ 38	$ 9	$ 12	$ 19

12. Equity and Preferred Stock of Subsidiaries

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

	Common Stock ($0.01/Share)	Convertible Preferred Stock (4.99%/Year)
Amount paid through September 30, 2010	$ 21	$ 28
Amount paid in October 2010	$ 7	$ 9
Declared in October 2010:		
Date of declaration	October 14, 2010	October 14, 2010
Payable to shareholders on record	December 3, 2010	December 15, 2010
Date payable	January 3, 2011	January 3, 2011

Dividends on our common stock and preferred stock are treated as a reduction of additional paid-in-capital since we currently have an accumulated deficit. For the remainder of 2010, 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. Our ability to pay dividends can be impacted by certain restrictions as further described in our 2009 Annual Report on Form 10-K.

Noncontrolling Interests. During the first half of 2010, we contributed a 51 percent interest in Southern LNG Company, L.L.C. (SLNG), which owns the Elba Island LNG receiving terminal, a 51 percent interest in El Paso Elba Express Company, L.L.C. (Elba Express), which owns the Elba Express Pipeline, and an additional 20 percent interest in Southern Natural Gas Company (SNG) to EPB in exchange for $1.3 billion which included cash and 5.3 million EPB common units. EPB raised the funds for the acquisitions primarily through the issuance of 21.4 million common units, which increased our noncontrolling interests, and the proceeds from debt offerings. In September 2010, EPB issued a total of 13.2 million common units to the public and 0.3 million general partner units to us. As of September 30, 2010, our ownership interest in EPB is 54 percent, including our 2 percent general partner interest.

EPB makes quarterly distributions of available cash to its unitholders in accordance with its partnership agreement. During the nine months ended September 30, 2010 and 2009, EPB made cash distributions of $64 million and $33 million to its non-affiliated common unitholders. We have recorded net income attributable to noncontrolling interest holders of $25 million and $15 million during the quarters ended September 30, 2010 and 2009, and $75 million and $38 million during the nine months ended September 30, 2010 and 2009, which represents the non-affiliated common unitholders share of EPB s income.

Preferred Stock of Subsidiaries. During 2009, Global Infrastructure Partners (GIP), our partner on our Ruby pipeline project, contributed $145 million to our subsidiary, Ruby Pipeline Holding Company, L.L.C. (Ruby) and received a convertible preferred equity interest in Ruby that was simultaneously exchanged for a convertible preferred equity interest in Cheyenne Plains Investment Company, L.L.C. (Cheyenne Plains). GIP earns a 15 percent dividend on its preferred interests in Cheyenne Plains. In addition, GIP provided a $405 million loan for Ruby project funding. During the third quarter of 2010, GIP s loan of $405 million was converted to a convertible preferred equity interest in Ruby. In addition, GIP provided an additional $120 million contribution for a convertible preferred equity interest in Ruby. GIP will earn a 13 percent return on its convertible preferred interests in Ruby beginning on the date Ruby is placed in service. For a further discussion of the Ruby transaction, see Note 14.

The convertible preferred equity interests in Cheyenne Plains and Ruby have been classified between liabilities and equity on our balance sheet since the events that require redemption of the preferred interests are not entirely within our control and are not certain to occur. We paid preferred dividends of $5 million and $15 million on GIP s preferred interest in Cheyenne Plains for the quarter and nine months ended September 30, 2010. Also, for the nine months ended September 30, 2010, we recognized a return of $11 million on GIP s preferred interest in Ruby. Both the preferred dividends and the return on GIP s preferred interests are reflected in net income attributable to noncontrolling interests on our income statement.

The components of net income attributable to noncontrolling interests on our statements of income for the quarters and nine months ended September 30, are as follows:

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(In millions)			
EPB	$ 25	$ 15	$ 75	$ 38
Preferred Stock of Cheyenne Plains	5		15	
Preferred Stock of Ruby	11		11	
Net income attributable to noncontrolling interests	$ 41	$ 15	$ 101	$ 38

13. Business Segment Information

As of September 30, 2010, our business consists of two core segments, Pipelines and Exploration and Production, as well as our Marketing segment. Our segments are strategic business units that provide a variety of energy products and services. They are managed separately as each segment requires different technology and marketing strategies. Prior to 2010, we also had a Power segment which has been combined into our corporate and other activities for all periods presented. A further discussion of each segment and our corporate and other activities follows.

Pipelines. Our Pipelines segment provides natural gas transmission, storage, and related services, primarily in the United States. As of September 30, 2010, we conducted our activities primarily through eight wholly or majority owned interstate pipeline systems and equity interests in two transmission systems. In addition to the storage capacity in our wholly and majority owned pipelines systems, we also own or have interests in three underground natural gas storage facilities and two LNG terminal facilities, one of which is under construction.

Exploration and Production. Our Exploration and Production segment is 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. Our Marketing segment markets and manages the price risks associated with our natural gas and oil production as well as manages our remaining legacy trading portfolio.

Corporate and Other. Our corporate and other activities include our general and administrative functions, our emerging midstream business, our remaining power operations, and other miscellaneous businesses.

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,	
	2010	2009	2010	2009
	(In millions)			
Segment EBIT	$ 583	$ 386	$ 1,908	$ (453)
Corporate and Other	(111)	(28)	(96)	(21)
Consolidated EBIT	472	358	1,812	(474)
Interest and debt expense	(255)	(256)	(782)	(764)
Income tax benefit (expense)	(75)	(35)	(343)	425
Net income (loss) attributable to El Paso Corporation	142	67	687	(813)
Net income attributable to noncontrolling interests	41	15	101	38
Net income (loss)	$ 183	$ 82	$ 788	$ (775)

The following table reflects our segment results for the quarters and nine months ended September 30:

	Segments				
	Pipelines	Exploration and Production	Marketing	Corporate and Other[1]	Total
			(In millions)		
Quarter Ended September 30, 2010					
Revenue from external customers	$ 680	$ 340[2]	$ 174	$ 19	$ 1,213
Intersegment revenue	12	179[2]	(190)	(1)	
Operation and maintenance	220[3]	87	(3)	23	327
Ceiling test charges		14			14
Depreciation, depletion and amortization	111	117		11	239
Earnings (losses) from unconsolidated affiliates	28	(2)		2	28
EBIT	334	261	(12)	(111)[4]	472
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	28	346
Ceiling test charges		5			5
Depreciation, depletion and amortization	104	93		3	200
Earnings (losses) from unconsolidated affiliates	27	(7)		(9)	11
EBIT	326	88	(28)	(28)	358

(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, 2010 and 2009, we recorded an intersegment revenue elimination of $8 million and $3 million in the Corporate and Other column to remove intersegment transactions.

(2) Revenues from external customers include gains of $184 million and $87 million for the quarters ended September 30, 2010 and 2009 related to our financial derivative contracts 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.

(3) Includes a $21 million non-cash asset write down based on a FERC order

related to the sale of a compressor station and gas processing plant in 2009.

(4) Includes a $104 million loss on debt extinguishment as further discussed in Note 4.

	Segments				
	Pipelines	Exploration and Production	Marketing	Corporate and Other[1]	Total
			(In millions)		
Nine Months Ended September 30, 2010					
Revenue from external customers	$ 2,072	$ 966[2]	$ 556	$ 38	$ 3,632
Intersegment revenue	37	569[2]	(601)	(5)	
Operation and maintenance	599[4]	275		37	911
Ceiling test charges		16			16
Depreciation, depletion and amortization	327	352		20	699
Earnings (losses) from unconsolidated affiliates	157[3]	(3)		13	167
EBIT	1,198	754	(44)	(96)[5]	1,812
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	10	910
Ceiling test charges		2,085			2,085
Depreciation, depletion and amortization	310	334		9	653
Earnings (losses) from unconsolidated affiliates	73	(29)		(2)	42
EBIT	1,049	(1,536)	34	(21)	(474)

(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, 2010 and 2009, we recorded an intersegment revenue elimination of $16 million and $8 million in the Corporate and Other column to remove intersegment transactions.

(2) Revenues from external customers include gains of $468 million and $536 million for the nine months ended September 30, 2010 and 2009 related to our financial derivative contracts 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.

(3) Includes a gain of approximately $80 million related to the sale of certain of

our interests in Mexican pipeline and compression assets.

(4) Includes a $21 million non-cash asset write down based on a FERC order related to the sale of a compressor station and gas processing plant in 2009.

(5) Includes a $104 million loss on debt extinguishment as further discussed in Note 4.

Total assets by segment are presented below:

	September 30, 2010	December 31, 2009
	(In millions)	
Pipelines	$ 18,932	$ 17,324
Exploration and Production	4,652	4,025
Marketing	213	345
Total segment assets	23,797	21,694
Corporate and Other	710	811
Total consolidated assets	$ 24,507	$ 22,505

14. Variable Interest Entities and Accounts Receivable Sales Programs

Ruby. We consolidate our investment in Ruby, a variable interest entity that owns our Ruby pipeline project, as its primary beneficiary. In July 2009, we entered into an agreement with GIP whereby they agreed to invest up to $700 million and acquire a 50 percent equity interest in Ruby subject to certain conditions. As part of this agreement, GIP (i) contributed $145 million in exchange for a convertible preferred equity interest in Ruby that was simultaneously exchanged for a convertible preferred equity interest in Cheyenne Plains (a variable interest entity that we consolidate as its primary beneficiary) and (ii) provided a $405 million loan for Ruby project funding.

In the second quarter of 2010, we received certification from the FERC authorizing the project and entered into a $1.5 billion third party project financing facility. In July 2010, we received a Bureau of Land Management (BLM) right-of-way grant, received final approval from the FERC and began construction of the Ruby pipeline.

Several groups have filed appeals of certain approvals and actions of the BLM and the U.S. Fish and Wildlife Service related to the project. We are currently unable to predict what action, if any, the court will take in response to these appeals or any subsequent filings that may be made by one or more of these groups.

During the third quarter of 2010, (i) GIP s loan of $405 million was converted to a convertible preferred equity interest in Ruby; (ii) GIP provided an additional $120 million contribution for a convertible preferred equity interest in Ruby and (iii) we borrowed approximately $362 million under the $1.5 billion facility. In October 2010, we made an additional draw of approximately $240 million on the facility.

GIP will hold its interest in Cheyenne Plains until certain conditions are satisfied, including placing the Ruby pipeline project in service. GIP has the right to convert its preferred equity in Ruby to common equity in Ruby at any time; however, the preferred equity is subject to mandatory conversion to Ruby common equity upon the satisfaction of certain conditions, including Ruby entering into additional firm transportation agreements.

If all conditions to completion are satisfied or waived, GIP would own a 50 percent equity interest in Ruby and all ownership in Cheyenne Plains would be transferred back to us. However, if certain conditions are not satisfied including placing the Ruby pipeline project in service by November 2011, GIP has the option to convert its Cheyenne Plains preferred interest to a common interest and/or be repaid in cash for its remaining investments in Cheyenne Plains and Ruby including a 15 percent return on its investments in Cheyenne Plains and Ruby. Our obligation to repay these amounts is secured by our equity interests in Ruby, Cheyenne Plains, and approximately 50 million common units we own in EPB. For a further discussion of our Ruby transaction, refer to Note 12 and our 2009 Annual Report on Form 10-K.

Other. We also 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.

Accounts Receivable Sales Programs. During 2009, several of our pipeline subsidiaries had agreements to sell senior interests in certain of their accounts receivable (which are short-term assets that generally settle within 60 days) to a third party financial institution (through wholly-owned special purpose entities), and we retained subordinated interests in those receivables. The sale of these senior interests qualified for sale accounting and was conducted to accelerate cash from these receivables, the proceeds from which were used to increase liquidity and lower our overall cost of capital. During the quarter and nine months ended September 30, 2009, we received $230 million and $709 million of cash related to the sale of the senior interests, collected $197 million and $686 million from the subordinated interests we retained in the receivables, and recognized a loss of approximately $1 million on these transactions. At December 31, 2009, the third party financial institution held $90 million of senior interests and we held $79 million of subordinated interests. Our subordinated interests are reflected in accounts receivable on our balance sheet. In January 2010, we terminated these accounts receivable sales programs and paid $90 million to acquire the senior interests. We reflected the cash flows related to the accounts receivable sold under this program, changes in our retained subordinated interests, and cash paid to terminate the programs, as operating cash flows on our statement of cash flows.

In the first quarter of 2010, we entered into new accounts receivable sales programs to continue to sell accounts receivable to the third party financial institution that qualify for sale accounting under the updated accounting standards related to financial asset transfers, and to include an additional pipeline subsidiary s accounts receivable in the program. Under these programs, several of our pipeline subsidiaries sell receivables in their entirety to the third-party financial institution (through wholly-owned special purpose entities). As of September 30, 2010, the third-party financial institution held $195 million of the accounts receivable we sold under the program. In connection with our accounts receivable sales, we receive a portion of the sales proceeds up front and receive an additional amount upon the collection of the underlying receivables. Our ability to recover this additional amount is based solely on the collection of the underlying receivables. During the quarter and nine months ended September 30, 2010, we received $338 million and $1.1 billion of cash up front from the sale of the receivables and received an additional $266 million and $746 million of cash upon the collection of the underlying receivables. As of September 30, 2010, we had not collected approximately $81 million related to our accounts receivable sales, which is reflected as other accounts receivable on our balance sheet (and was initially recorded at an amount which approximates its fair value as a Level 2 measurement). We recognized a loss of approximately $1 million and $2 million on our accounts receivable sales during the quarter and nine months ended September 30, 2010. Because the cash received up front and the cash received as the underlying receivables are collected relate to the sale or ultimate collection of the underlying receivables, and are not subject to significant other risks given their short term nature, we reflect all cash flows under the new accounts receivable sales programs as operating cash flows on our statement of cash flows.

Under both the prior and current accounts receivable sales programs, we serviced the underlying receivables for a fee. The fair value of these servicing agreements as well as the fees earned were not material to our financial statements for the periods ended September 30, 2010 and 2009.

The third party financial institution involved in both of these accounts receivable sales programs acquires interests in various financial assets and issues commercial paper to fund those acquisitions. We do not consolidate the third party financial institution because we do not have the power to direct its overall activities (and do not absorb a majority of its expected losses) since our receivables do not comprise a significant portion of its operations.

15. 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 on our income statement include (i) our share of net earnings directly attributable to these unconsolidated affiliates, and (ii) impairments, gains and losses on divestitures 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, 2010	December 31, 2009	September 30, 2010	2009	September 30, 2010	2009
	(In millions)		(In millions)			
Net Investment and Earnings (Losses)						
Four Star [1]	$ 408	$ 450	$ (2)	$ (7)	$ (3)	$ (29)
Citrus	704	630	27	20	67	54
Gulf LNG[2]	252	285	(1)	(1)	(1)	(2)
Gasoductos de Chihuahua[3]		184		5	88	17
Bolivia-to-Brazil Pipeline	102	105	1	(6)	10	(7)
Other	72	64	3		6	9
Total	$ 1,538	$ 1,718	$ 28	$ 11	$ 167	$ 42

(1) We recorded amortization of our purchase cost in excess of the underlying net assets of Four Star of $9 million and $12 million for the quarters ended September 30, 2010 and 2009 and $28 million

and $37 million for the nine months ended September 30, 2010 and 2009.

(2) As of September 30, 2010 and December 31, 2009, we had outstanding advances and receivables of $78 million and $56 million, not included above, related to our investment in Gulf LNG.

(3) In April 2010, we completed the sale of our interest in this investment and recorded a pretax gain of approximately $80 million. See Note 2.

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2010	**2009**	**2010**	**2009**
	(In millions)			
Summarized Financial Information				
Operating results data:				
Operating revenues	$ 126	$ 124	$ 386	$ 382
Operating expenses	63	58	201	195
Net income	40	34	119	93

We received distributions and dividends from our unconsolidated affiliates of $17 million and $25 million for the quarters ended September 30, 2010 and 2009 and $53 million and $61 million for the nine months ended September 30, 2010 and 2009. Included in these amounts are returns of capital of $1 million or less for the quarter and nine months ended September 30, 2010 and $1 million and $2 million for the quarter and nine months ended September 30, 2009. Our transactions with unconsolidated affiliates were not material during the quarters and nine months ended September 30, 2010 and 2009.

Other Investment-Related Matters. We currently have outstanding disputes and other matters related to an investment in two Brazilian power plant facilities (Manaus/Rio Negro) formerly owned by us. We have filed lawsuits to collect amounts due to us (approximately $68 million of Brazilian reais-denominated accounts receivable) by the plant s power purchaser, which are also guaranteed by the purchaser s parent. The power utility that purchased the power from these facilities and its parent have asserted counterclaims that would largely offset our accounts receivable.

Our project companies that previously owned the the Manaus and Rio Negro power plants have also been assessed approximately $75 million of Brazilian reais-denominated ICMS taxes by the Brazilian taxing authorities for payments received by the companies from the plants power purchaser from 1999 to 2001. By agreement, the power purchaser must indemnify our project companies for these ICMS taxes, along with related interest and penalties, and has therefore been defending the projects against this lawsuit. In order to prevent further collection efforts by the tax authorities for this matter, security must be provided for the potential tax liability to the court s satisfaction. The tax authorities and court have rejected the assets pledged by the power purchaser to date, and during the third quarter of 2010 the tax courts blocked certain of El Paso s bank accounts associated with the Rio Negro power plant in order to obtain this security. The power purchaser has appealed the court s decision. If the power purchaser is unable to resolve this tax matter, our ability to collect amounts due to us from the power purchaser could be impacted. Any potential taxes owed by the Manaus and Rio Negro project companies are also guaranteed by the purchaser s parent.

The ultimate resolution of the matters discussed above is unknown at this time, and adverse developments related to either our ability to collect amounts due to us or related to these disputes and claims could require us to record additional losses in the future.

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 2009 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 2010, our primary focus has been on the execution of our business plan, delivering on our backlog of expansion projects in our pipeline segment, and continued operational success in our exploration and production business. Our operating and financial results and outlook are discussed further in individual segment results.

In our pipeline business, EBIT for the quarter and nine months in 2010 was up 2 percent and 14 percent over the same periods in 2009, driven primarily by income on expansion projects and a gain on the sale of our Mexico Pipeline assets during the second quarter. Approximately 80 percent of our pipeline revenues are collected in the form of demand or reservation charges, which are not dependent upon commodity prices or throughput levels. This, coupled with the diversity of our pipeline systems, helps mitigate against the risk of changes in throughput and ongoing shifts in supply and demand. Operationally, total pipeline throughput was down 3 percent year to date in 2010 versus the same period in 2009. During 2010, we experienced lower demand and firm transportation commitments on our EPNG system and long haul transportation being replaced by short haul transportation on our Tennessee Gas Pipeline (TGP) system. As we experience shifts in gas flows, demand changes and changes in firm transportation commitments, we evaluate whether to file rate cases. Currently, one of our pipelines has an outstanding rate case pending before the FERC and certain of our other pipelines have projected upcoming rate actions with anticipated effective dates from 2011 through 2014. Changes in gas flows and the outcome of our rate cases can impact the financial performance of our pipeline segment.

In our pipeline business, we will continue to focus on execution of our pipeline backlog, a multi-year expansion program, the bulk of which occurs in 2010 and 2011. In 2010, we have placed three projects in service, and expect to place two additional projects in service in the fourth quarter, all on time and in total, expected to be approximately $100 million under budget. On Ruby, our largest project, we began construction in mid-2010. Based on delays in obtaining regulatory clearances, we currently expect that the project will be completed in June 2011, three months later than originally anticipated, and will be approximately 10 to 15 percent over budget. Overall, we expect our multi-year pipeline expansion backlog to be within 5 percent of our original budgets.

In our exploration and production business, we have continued executing on our strategy, with production volumes up slightly over 2009, lower per unit cash operating costs, and by expanding our 2011 and 2012 hedging programs designed to support our balance sheet and cash flows. Hedges on our 2010 natural gas production have allowed us to achieve a realized price of $5.93 per Mcf in 2010, at a time where realized prices in 2010 on physical sales of natural gas have been declining. We expect this trend of lower natural gas prices to continue, and we are currently hedged on approximately 60 percent of our remaining domestic natural gas volumes in 2010. Our expanded 2011 and 2012 oil and natural gas production hedges will help protect our cash flows in these years.

We have shifted capital in our exploration and production business toward our core programs: Haynesville, Eagle Ford and Altamont. In addition, we have focused on execution and cost management to ensure favorable economics of our programs in the current low gas price environment. In September, we leased approximately 123,000 acres in the Wolfcamp Shale play in the Permian Basin for approximately $180 million. The Wolfcamp Shale is an emerging oil shale play that will represent a new opportunity for us in 2011. The shift in our capital program to more activity in Eagle Ford and Altamont, as well as the expansion of our acreage position in Wolfcamp provides us greater exposure to oil or natural gas liquids opportunities. We intend to fund the cost of the acquired acreage in Wolfcamp over time through portfolio rationalization, and future development capital will compete with other programs in the portfolio. We are also considering securing a joint venture partner for our Eagle Ford acreage to accelerate development of this core area and optimize our total portfolio.

We continue to seek out opportunities for our emerging Midstream business and have several projects under development that focus on synergies with our pipeline and/or exploration and production businesses. We will continue to focus on funding these projects in a manner that is consistent with our long-term goal of improving our balance sheet, including the evaluation of partnership opportunities on our projects.

From a liquidity perspective, we have funded our 2010 capital and liquidity needs largely through cash flow from operations and funds provided through capital market activities (including execution on our financing strategy utilizing EPB), bank facilities, project financings (including Ruby) and asset sales. By June of this year, we had met our 2010 funding needs, and our activities for the remainder of the year will be focused on meeting our 2011 funding objectives. As of September 30, 2010, we had approximately $2.5 billion of available liquidity (exclusive of cash and credit facility capacity of EPB and Ruby) and believe we are well positioned to meet our current obligations based on the anticipated performance of our core businesses, our financing actions taken to date and our available liquidity. We will, however, continue to assess and take further actions where prudent to meet our long-term objectives and capital requirements. See *Liquidity and Capital Resources* for a further discussion of our financing and capital activities.

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. Our segments are managed separately, provide a variety of energy products and services, and require different technology and marketing strategies. Prior to 2010, we also had a Power segment which has been combined into our corporate and other activities for all periods presented. Our corporate and other activities include our general and administrative functions, our emerging midstream business, our remaining power operations, and other miscellaneous businesses.

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 measurements 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 quarters and nine months ended September 30:

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(In millions)			
Segment				
Pipelines	$ 334	$ 326	$ 1,198	$ 1,049
Exploration and Production	261	88	754	(1,536)
Marketing	(12)	(28)	(44)	34
Segment EBIT	583	386	1,908	(453)
Corporate and Other	(111)	(28)	(96)	(21)
Consolidated EBIT	472	358	1,812	(474)
Interest and debt expense	(255)	(256)	(782)	(764)
Income tax benefit (expense)	(75)	(35)	(343)	425
Net income (loss) attributable to El Paso Corporation	142	67	687	(813)
Net income attributable to noncontrolling interests	41	15	101	38
Net income (loss)	$ 183	$ 82	$ 788	$ (775)

Pipelines Segment

Overview and Operating Results. Our Pipelines segment EBIT for the quarter and nine months ended September 30, 2010 increased 2 percent and 14 percent from the same periods in 2009, and includes the impact of an $80 million gain recorded during the second quarter of 2010 on the sale of certain of our interests in Mexican pipeline and compression assets. During the first nine months of 2010, we also benefited from several expansion projects placed in service in 2010 and 2009 and other income associated with AFUDC primarily on our Ruby pipeline project. Below are the operating results for our Pipelines segment as well as a discussion of factors impacting EBIT for the quarters and nine months ended September 30, 2010 and 2009, or that could potentially impact EBIT in future periods.

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(In millions, except for volumes)			
Operating revenues	$ 692	$ 667	$ 2,109	$ 2,050
Operating expenses	(402)	(373)	(1,128)	(1,104)
Operating income	290	294	981	946
Other income, net	85	47	318	141
EBIT before adjustment for noncontrolling interests	375	341	1,299	1,087
Net income attributable to noncontrolling interests	(41)	(15)	(101)	(38)
EBIT	$ 334	$ 326	$ 1,198	$ 1,049
Throughput volumes (BBtu/d)[1]	17,047	17,757	17,971	18,460

[1] Throughput volumes include our proportionate share of unconsolidated affiliates and exclude intrasegment activities.

	Quarter Ended September 30, 2010 Variance				Nine Months Ended September 30, 2010 Variance			
	Operating Revenue	Operating Expense	Other	Total	Operating Revenue	Operating Expense	Other	Total
	Favorable/(Unfavorable) (In millions)							
Expansions	$ 50	$ (10)	$ 34	$ 74	$ 126	$ (25)	$ 92	$ 193
Reservation and usage revenues	(6)			(6)	(6)	3		(3)
	(18)	(5)		(23)	(63)	10		(53)

Gas not used in operations and revaluations								
Operating and general and administrative expenses		8		8		15		15
Asset write downs		(21)		(21)		(28)		(28)
Sale of Mexican assets							80	80
Other[1]	(1)	(1)	4	2	2	1	5	8
Total impact on EBIT before adjustment for noncontrolling interests	25	(29)	38	34	59	(24)	177	212
Net income attributable to noncontrolling interests			(26)	(26)			(63)	(63)
Total impact on EBIT	$ 25	$ (29)	$ 12	$ 8	$ 59	$ (24)	$ 114	$ 149

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

Expansions. During the first nine months of 2010, we made progress on our backlog of expansion projects and benefited from increased reservation revenues due to projects placed in service in 2009 and 2010. These projects included the Carthage expansion project, the Totem Gas Storage facility, the Concord Lateral expansion, the Wyoming Interstate (WIC) Piceance Lateral expansion, the Phase A of the SLNG Elba Expansion III and the Elba Express Pipeline expansion. See below for further updates of our expansion projects.

We capitalize a carrying cost (AFUDC) on equity funds related to our construction of long-lived assets. During the quarter and nine months ended September 30 2010, we benefited from an increase in other income of approximately $34 million and $92 million associated with the pretax equity portion of AFUDC on our expansion projects. This increase is primarily due to our Ruby pipeline project. We will continue to record AFUDC until our Ruby project and other pipeline expansion projects are placed in service. Subsequent to placing these projects in service, our level of earnings will depend on the level of contracted customer capacity and our ability to market unsubscribed firm capacity. Additionally, shortly after completion of the Ruby project, subject to meeting certain conditions, we anticipate reflecting Ruby in our financial statements as an equity investment. Consequently, we would reflect equity earnings from Ruby in EBIT after the impact of interest and taxes.

Listed below are significant additional updates to our backlog of projects discussed in our 2009 Annual Report on Form 10-K.

Ruby Pipeline Project. In 2010, we received a BLM right-of-way grant for the project, final approval from the FERC and began construction of the pipeline. Although we will need additional authorizations from the FERC to construct in certain areas of the route, we expect to receive them as we satisfy various regulatory conditions and requirements, such as implementing required historic resource protection plans. Several groups have filed appeals with the U.S. Court of Appeals of certain approvals and actions of the BLM and the U.S. Fish and Wildlife Service related to the project. Although we are currently able to continue construction of the pipeline pending the federal court of appeals review of the petition, we are currently unable to predict what action, if any, the court will take in response to these appeals or any subsequent filings that may be made by one or more of these groups.

As a result of delays in obtaining regulatory clearances to commence construction on portions of the route, we expect that the in-service date will be delayed from the original March 2011 date to June 2011 and that the costs of completing the project will be approximately 10 to 15 percent over the original cost estimate of $3.0 billion. This schedule and cost forecast could be negatively impacted by various factors, including the timing of additional regulatory clearances, adverse weather conditions in the winter season and our ability to complete construction activities during certain work periods provided for in our regulatory authorizations.

CIG Raton 2010 Expansion. In 2010, CIG received certificate authorization from the FERC to construct the expansion which is expected to be placed in service in the fourth quarter of 2010.

WIC System Expansion. During 2010, WIC received certificate authorization from the FERC to construct the WIC Expansion project, which will add a compressor station on the Kanda Lateral and install three miles of pipeline and reconfigure one compressor at the Wamsutter station. We placed both portions of the WIC Expansion project in service in November 2010.

SNG South System III. The South System III expansion project will be completed in three phases with estimated in service dates in the fourth quarter of 2010 for Phase I, June 2011 for Phase II and June 2012 for Phase III. Construction agreements have been finalized for Phases I and II.

TGP Northeast Upgrade Project. In 2010, TGP entered into precedent agreements with two shippers to provide 620 MMcf/d of additional firm transportation service from receipt points in the Marcellus shale basin to an interconnect in New Jersey.

TGP 300 Line Expansion. During 2010, the FERC issued a favorable environmental assessment and TGP received certificate authorization from the FERC to construct the expansion. In June 2010, we commenced construction on our compression facilities related to this project.

TGP Northeast Supply Diversification Project. During 2010, we entered into precedent agreements with three shippers to provide up to approximately 250 MMcf/d of additional firm transportation service from receipt points in the Marcellus shale basin to delivery points in the New York and New England markets. Total estimated cost of this project is less than $100 million. Subject to FERC and other approvals, the project is expected to commence construction in the first half of 2012 and is anticipated to be placed in service in the fourth quarter of 2012.

Reservation and Usage Revenues. During the quarter and nine months ended September 30, 2010, our reservation and usage revenues were unfavorably impacted by lower rates and throughput on our El Paso Natural Gas Company (EPNG) system and lower usage revenues on our TGP system, partially offset by higher tariff rates on our SNG system effective September 1, 2009 pursuant to its rate case settlement. During 2010, EPNG has experienced a decrease in natural gas and electric generation demand due to weak macroeconomic conditions in the southwestern U.S., increased competition in its California and Arizona market areas and reduced basis differentials. During the quarter and nine months ended September 30, 2010, throughput volumes on our TGP system increased by 16 percent and six percent compared to the same periods in 2009; however, usage revenue was lower because TGP s long-haul transports decreased due to a shift in receipts from the Gulf Coast region to the Rockies Express Pipeline interconnect and the Marcellus shale basin, which is short-haul transportation and subject to lower rates. We believe our Marcellus expansion projects (TGP 300 Line Expansion, TGP Northeast Upgrade Project, and TGP Northeast Supply Diversification Project) will expand our presence from Marcellus to the New York and New England markets.

Although approximately 80 percent of our pipeline revenues are derived from reservation charges, lower throughput can affect our level of revenues from commodity charges, such as on our TGP system, or 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. Although this risk exists for all of our pipelines, it is the most significant on our EPNG system where we may be required to further discount certain transportation rates in order to renew certain firm transportation contracts should these conditions continue.

If we determine there is a significant change in our revenues, costs or billing determinants on any of our pipeline systems, we have the option to file rate cases with the FERC on certain of our pipelines to provide an opportunity to recover our prudently incurred costs. In September 2010, EPNG filed a new rate case with the FERC. Additionally, TGP anticipates filing a new rate case in November 2010. Although these rate cases are intended to address significant factors leading to the loss in revenues or increased costs, they will not eliminate all ongoing business risks.

Gas Not Used in Operations and Revaluations. During the quarter and nine months ended September 30, 2010 compared with the same periods in 2009, our EBIT, primarily on our TGP system, was negatively impacted by lower realized prices on operational sales and unfavorable revaluations, partially offset by positive impacts due to lower electric compression utilization and higher condensate sales. Our future earnings may be impacted positively or negatively depending on fluctuations in natural gas prices related to the revaluation of under or over recoveries, imbalances and system encroachments. We continue to explore options to minimize the price volatility associated with these operational pipeline activities.

Operating and General and Administrative Expenses. During the quarter and nine months ended September 30, 2010, our operating and general and administrative expenses were lower compared to the same periods in 2009 primarily due to lower payroll and benefits costs.

Asset Write Downs. During the third quarter of 2010, we incurred a $21 million non-cash asset write down based on a FERC order related to the sale of the Natural Buttes compressor station and gas processing plant in 2009. During the first quarter of 2010, we also recorded an impairment of approximately $10 million primarily related to our decision not to continue with a storage project due to market conditions.

Sale of Mexican Assets. During 2010, we recorded a gain of approximately $80 million on the sale of our interests in certain Mexican pipeline and compression assets.

Net Income Attributable to Noncontrolling Interests. During the quarter and nine months ended September 30, 2010, our net income attributable to noncontrolling interests increased as compared to the same period in 2009 due primarily to the issuance of additional public common units and the contribution of additional assets into the MLP. From July 2009 through September 2010, our MLP has issued 36.2 million additional public common units. Additionally, since July 2009, we have contributed an additional 18 percent interest in CIG, a 51 percent interest in SLNG and Elba Express and an additional 20 percent interest in SNG to our MLP. As of September 30, 2010, we owned 54 percent of the MLP, including our 2 percent general partner interest.

Noncontrolling interests also include preferred returns on GIP s interests in Cheyenne Plains and Ruby. During the quarter and nine months ended September 30, 2010, we recorded $16 million and $26 million associated with GIP s return on their preferred interests in Cheyenne Plains and Ruby. For further discussion of preferred stock of subsidiaries, see Item 1, Financial Statements, Note 12.

Other Regulatory Matters. Our pipeline systems periodically file for changes in their rates, which are subject to approval by 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 2014 as discussed below.

SNG Rate Case. In January 2010, the FERC approved SNG s rate case settlement in which SNG (i) increased its base tariff rates, effective September 1, 2009, (ii) implemented a volume tracker for gas used in operations, (iii) agreed to file its next general rate case to be effective after August 31, 2012 but no later than September 1, 2013, and (iv) extended the vast majority of SNG s firm transportation contracts until August 31, 2013.

EPNG Rate Case. In April 2010, the FERC approved an uncontested partial offer of settlement which increased EPNG s base tariff rates effective January 1, 2009. As part of the settlement, EPNG made an initial refund to its customers in April 2010, and paid the remaining refunds in August 2010. The settlement resolved all but four issues in the proceeding. A hearing on the remaining issues was completed in June 2010 and the outcome is not currently determinable. We believe our accruals established for this matter are adequate.

In September 2010, EPNG filed a new rate case with the FERC proposing an increase in its base tariff rates as permitted under the settlement of the previous rate case. These new base tariff rates would increase revenue by approximately $100 million annually over previously effective tariff rates. In October 2010, the FERC issued an order accepting and suspending the effective date of the proposed rates to April 1, 2011, subject to refund, the outcome of a hearing and other proceedings. At this time, the outcome of this matter is not currently determinable.

TGP Rate Case. TGP anticipates filing a new rate case in November 2010 with revised rates expected to become effective June 2011.

Exploration and Production Segment

Overview and Strategy

Our Exploration and Production segment conducts our natural gas and oil exploration and production activities. The profitability and performance of this segment are driven by the ability to locate and develop economic natural gas and oil reserves and extract those reserves at the lowest possible production and administrative costs. Accordingly, we manage this business with the goal of creating value through disciplined capital allocation, cost control and portfolio management. Our strategy focuses on building and applying competencies in assets with repeatable programs, executing to improve capital and expense efficiency, and maximizing returns by adding assets and inventory that match our competencies and divesting assets that do not. For a further discussion of our business strategy in our exploration and production business, see our 2009 Annual Report on Form 10-K.

Our profitability and performance is impacted by changes in commodity prices and industry-wide changes in the cost of drilling and oilfield services which impact our daily production, operating, and capital costs. Additionally we may be impacted by the effect of hurricanes and other weather events, or the effects of domestic or international regulatory or other actions in response to events outside of our control (e.g. oil spills). We attempt to mitigate certain of these risks through actions, such as entering into longer term contractual arrangements to control costs and entering into derivative contracts to reduce the financial impact of downward commodity price movements.

Significant Operational Factors Affecting the Periods Ended September 30, 2010

Production. Our average daily production for the nine months ended September 30, 2010 was 777 MMcfe/d, including 62 MMcfe/d from our equity interest in the production of Four Star. Below is an analysis of our production by division for the nine month periods ended September 30:

	2010	**2009**
	(MMcfe/d)	
United States		
Central	318	252
Western	159	158
Gulf Coast	206	279
International		
Brazil	32	9
Total Consolidated	715	698
Four Star	62	72
Total Combined	777	770

In the first nine months of 2010, production volumes increased in our Central division as a result of our successful Arklatex drilling programs, including the Haynesville Shale. As of September 30, 2010, we had 44 operated producing wells in the Haynesville Shale, with 13 wells awaiting completion, compared to 20 operated producing wells at December 31, 2009. Production volumes in our Gulf Coast division decreased primarily due to natural declines and lower levels of drilling activity. In this division, our focus in 2010 has been to advance our Eagle Ford Shale development, where we hold approximately 170,000 net acres as of September 30, 2010, and have drilled 13 successful wells, of which seven are currently producing. Approximately 60 percent of total net acres of our Eagle Ford Shale position are in the liquids rich area. During the third quarter of 2010, we acquired leases on approximately 123,000 acres in the Wolfcamp Shale in the Permian Basin in Reagan, Crockett, Upton and Irion counties in Texas for approximately $180 million, bringing our overall leasehold position in this shale to approximately 135,000 acres. In Brazil, our production volumes increased due to production from our Camarupim Field.

2010 Drilling Results

Our drilling results for the nine months ended September 30, 2010 are as follows:

Domestic. We achieved a 98 percent success rate on 176 gross wells drilled. By division, these results were as follows:

	Success Rate	**Gross Wells Drilled**
Central	99%	140
Western	100%	17
Gulf Coast	89%	19

International

Brazil. In Brazil, our activities are primarily in the Camamu and Espirito Santo Basins. During the first nine months of 2010, we continued to seek regulatory and environmental approvals that are required to enter the next phase of development in the Pinauna Field in the Camamu Basin. Our ability to develop this area will be dependent on the receipt of all required regulatory approvals. In the Espirito Santo Basin, the Camarupim Field began production from the second and third wells of a four well development program. We continue to work with Petrobras to connect the fourth well and anticipate bringing the well on production by the end of the first quarter of 2011. During the second quarter of 2010, we participated with Petrobras in drilling an additional exploratory well in the ES-5 block. Hydrocarbons were found in the well and we are now evaluating results. As of September 30, 2010, we have total capitalized costs in Brazil of approximately $363 million, of which $182 million are unevaluated capitalized costs.

Egypt. During the first nine months of 2010, we participated in drilling our fourth and fifth exploratory wells in the South Alamein block. The wells encountered oil shows but were temporarily plugged as we continue to evaluate the results. In the first quarter of 2010, we recorded a non-cash ceiling test charge of $2 million as a result of acreage relinquishment in the South Mariut block. During the third quarter of 2010, we recorded non-cash ceiling test charges of $14 million in our Egyptian full cost pool as a result of acreage relinquishments in the South Alamein block and a dry hole drilled in the Tanta block. Additionally, we relinquished the South Feiran concession in March 2010. As of September 30, 2010, we have total capitalized costs in Egypt of approximately $75 million, 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, 2010, cash operating costs per unit decreased to $1.76/Mcfe as compared to $1.83/Mcfe during the same period in 2009 primarily due to lower lease operating expenses and general and administrative expenses.

Capital Expenditures. Our total natural gas and oil capital expenditures were $1,040 million for the nine months ended September 30, 2010, of which $962 million were domestic capital expenditures.

Outlook for 2010

For the full year 2010, we expect the following on a worldwide basis:

- Capital expenditures of approximately $1.3 billion. This capital includes the leasehold acquisition in the Wolfcamp Shale for approximately $180 million during the third quarter of 2010. Of total capital expenditures, we expect to spend approximately $1.2 billion on our domestic program and approximately $0.1 billion in Brazil and Egypt;

- Average daily production volumes for the year of approximately 760 MMcfe/d to 780 MMcfe/d, which includes approximately 60 MMcfe/d to 65 MMcfe/d from Four Star. Production volumes from our Brazil operations are expected to be between 30 MMcfe/d and 35 MMcfe/d in 2010;

Average cash operating costs between $1.75/Mcfe and $1.85/Mcfe for the year; and a

Depreciation, depletion and amortization rate between $1.80/Mcfe and $1.85/Mcfe.

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 we apply mark-to-market accounting on our financial derivative contracts and because we do not hedge our entire price risk, 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 third quarter of 2010, we expanded our hedge positions for 2011 and 2012. We entered into transactions that exchanged substantially all of our 2011 natural gas collars for 2011 and 2012 natural gas fixed price swaps. We also entered into additional 2012 and 2013 crude oil transactions. 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, 2010.

	Fixed Price Swaps(1)		**Floors(1)**		**Ceilings(1)**		**Basis Swaps(1)(2)**							
									Western				**Central**	
							Texas Gulf Coast		**Raton**		**Rockies**		**Mid-Continent**	
	Volumes	**Average Price**	**Volumes**	**Average Price**	**Volumes**	**Average Price**	**Volumes**	**Average Price**	**Volumes**	**Average Price**	**Volumes**	**Average Price**	**Volumes**	**Average Price**
Natural Gas														
2010	31	$ 5.60	6	$ 7.00			12	$ (0.40)	5	$ (0.78)	2	$ (1.93)	3	$ (0.74)
2011	153	$ 6.00	18	$ 6.00	18	$ 7.29	33	$ (0.13)	22	$ (0.25)				
2012	64	$ 6.36												
Oil														
2010	773	$ 77.02	414	$ 75.00	414	$ 91.33								
2011			2,008	$ 80.00	2,008	$ 95.56								
2012					1,464	$ 95.00								
2013					1,825	$ 95.00								

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

(2) Our basis swaps effectively limit our exposure to differences between the NYMEX gas price and the

price at the location where we sell our gas. The average prices listed above are the amounts we will pay per MMBtu relative to the NYMEX price to lock-in these locational price differences.

During the nine months ended September 30, 2010, we also entered into offsetting fixed price swap transactions that effectively lock in a cash settlement of $8.78 above market prices on 2.5 MMBbls of our anticipated 2011 crude oil production.

In October 2010, we terminated our collars on 2.0 MMBbls of our anticipated 2011 oil production and entered into a combination of instruments (referred to as a three-way collar) on 3.7 MMBbls of our anticipated 2011 oil production. For these volumes, the transactions effectively provide an average ceiling price of $94.27 per barrel and an average floor price of $85.14 per barrel unless oil prices drop below $65.00 per barrel. If oil prices drop below $65.00 per barrel, the transactions effectively lock in a cash settlement of the market prices plus $20.14, which is the difference between the average floor price and $65.00. We also entered into fixed price swaps on 1.6 MMBbls of our anticipated 2011 oil production at an average price of $86.99 per barrel.

Internationally, production from the Camarupim Field in Brazil is sold at 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, 2010, we have fuel oil swaps that effectively lock in a price of approximately $4.00 per MMBtu on approximately 2 TBtu of projected Brazilian natural gas production in 2010.

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,		Nine Months Ended September 30,	
	2010	**2009**	**2010**	**2009**
		(In millions)		
Physical sales				
Natural gas	$ 239	$ 175	$ 755	$ 603
Oil, condensate and NGL	95	70	293	184
Total physical sales	334	245	1,048	787
Realized and unrealized gains on financial derivatives	184	87	468	536
Other revenues	1	11	19	29
Total operating revenues	519	343	1,535	1,352
Operating expenses				
Cost of products		8	15	21
Transportation costs	18	15	54	50
Production costs	61	61	194	193
Depreciation, depletion and amortization	117	93	352	334
General and administrative expenses	41	44	137	145
Ceiling test charges	14	5	16	2,085
Impairment of inventory		16		16
Other	3	4	12	10
Total operating expenses	254	246	780	2,854
Operating income (loss)	265	97	755	(1,502)
Other expense[(1)]	(4)	(9)	(1)	(34)
EBIT	$ 261	$ 88	$ 754	$ (1,536)

(1) Includes equity earnings from Four Star, our unconsolidated affiliate, net of amortization of our purchase cost in excess of our equity interest in the underlying net assets.

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

	Quarters Ended September 30,			Nine Months Ended September 30,		
	2010	**2009**	**Percent Variance**	**2010**	**2009**	**Percent Variance**
Volumes						
Natural gas (MMcf)						
Consolidated volumes	55,331	52,805	5%	167,839	164,728	2%
Unconsolidated affiliate volumes	4,350	4,823	(10)%	12,708	14,726	(14)%
Oil, condensate and NGL (MBbls)						
Consolidated volumes	1,540	1,336	15%	4,574	4,296	6%
Unconsolidated affiliate volumes	230	282	(18)%	707	841	(16)%
Equivalent volumes						
Consolidated MMcfe	64,575	60,825	6%	195,286	190,505	3%
Unconsolidated affiliate MMcfe	5,729	6,515	(12)%	16,948	19,774	(14)%
Total combined MMcfe	70,304	67,340	4%	212,234	210,279	1%
Consolidated MMcfe/d	702	661	6%	715	698	2%
Unconsolidated affiliate MMcfe/d	62	71	(13)%	62	72	(14)%
Total combined MMcfe/d	764	732	4%	777	770	1%
Consolidated prices and costs per unit						
Natural gas ($/Mcf)						
Average realized price on physical sales	$ 4.31	$ 3.32	30%	$ 4.50	$ 3.66	23%
Average realized price, including financial derivative cash settlements [(1)]	$ 5.93	$ 7.37	(20)%	$ 5.95	$ 7.67	(22)%
Average transportation costs	$ 0.30	$ 0.24	25%	$ 0.30	$ 0.28	7%
Oil, condensate and NGL ($/Bbl)						
Average realized price on physical sales	$ 62.10	$ 52.22	19%	$ 64.09	$ 42.72	50%
	$ 62.51	$ 82.25	(24)%	$ 63.71	$ 75.66	(16)%

Average realized price, including financial derivative cash settlements[1][2]						
Average transportation costs	$ 0.81	$ 0.80	1%	$ 0.76	$ 0.85	(11)%
Production costs and other cash operating costs ($/Mcfe)						
Average lease operating expenses	$ 0.70	$ 0.77	(9)%	$ 0.71	$ 0.76	(7)%
Average production taxes[3]	0.24	0.24	%	0.29	0.26	12%
Total production costs	$ 0.94	$ 1.01	(7)%	$ 1.00	$ 1.02	(2)%
Average general and administrative expenses	0.63	0.73	(14)%	0.70	0.76	(8)%
Average taxes, other than production and income taxes	0.05	0.04	25%	0.06	0.05	20%
Total cash operating costs	$ 1.62	$ 1.78	(9)%	$ 1.76	$ 1.83	(4)%
Depreciation, depletion and amortization ($/Mcfe)[4]	$ 1.81	$ 1.54	18%	$ 1.80	$ 1.75	3%

(1) Premiums paid in 2009 related to natural gas derivatives settled during the quarter and nine months ended September 30, 2010 were $48 million and $148 million. Had we included these premiums in our natural gas average realized prices in 2010, our realized price, including financial derivative settlements, would have decreased by

$0.88/Mcf for the quarter and nine months ended September 30, 2010. We had no cash 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, 2010 and 2009.

(2) Amounts for the quarter and nine months ended September 30, 2009, include approximately $50 million and $137 million related to $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.

(3) Production taxes include ad valorem and

severance taxes.

(4) Includes \$0.06 per Mcfe and \$0.07 per Mcfe for the quarters ended September 30, 2010 and 2009 and \$0.07 per Mcfe and \$0.06 per Mcfe for the nine months ended September 30, 2010 and 2009 related to accretion expense on asset retirement obligations.

Quarter and Nine Months Ended September 30, 2010 Compared to Quarter and Nine Months Ended September 30, 2009

Our EBIT for the quarter and nine months ended September 30, 2010 increased $173 million and $2.3 billion as compared to the same periods in 2009. The table below shows the significant variances of our financial results for the quarter and nine months ended September 30, 2010 as compared to the same periods in 2009:

	Quarter Ended September 30, 2010 Variance				**Nine Months Ended September 30, 2010 Variance**			
	Operating Revenue	**Operating Expense**	**Other**	**EBIT**	**Operating Revenue**	**Operating Expense**	**Other**	**EBIT**
	Favorable/(Unfavorable) (In millions)							
Physical sales								
Natural gas								
Higher realized prices in 2010	$ 55	$	$	$ 55	$ 140	$	$	$ 140
Higher volumes in 2010	9			9	12			12
Oil, condensate and NGL								
Higher realized prices in 2010	15			15	98			98
Higher volumes in 2010	10			10	11			11
Realized and unrealized gains on financial derivatives	97			97	(68)			(68)
Other revenues	(10)			(10)	(10)			(10)
Depreciation, depletion and amortization expense								
Higher depletion rate in 2010		(18)		(18)		(10)		(10)
Higher production volumes in 2010		(6)		(6)		(8)		(8)
Production costs								
Lower lease operating expenses in 2010		2		2		7		7
Higher production taxes in 2010		(2)		(2)		(8)		(8)
Ceiling test charges		(9)		(9)		2,069		2,069
Impairment of inventory		16		16		16		16
Earnings from investment in Four Star			5	5			26	26
Other		9		9		8	7	15

Total Variances	$ 176	$ (8)	$ 5	$ 173	$ 183	$ 2,074	$ 33	$ 2,290

Physical sales. Physical sales represent accrual-based commodity sales transactions with customers. During the quarter and nine months ended September 30, 2010, natural gas, oil, condensate and NGL revenues increased as compared to the same periods in 2009 due to higher commodity prices and higher production volumes.

Realized and unrealized gains on financial derivatives. During the quarter and nine months ended September 30, 2010, we recognized net gains of $184 million and $468 million compared to net gains of $87 million and $536 million during the same periods in 2009. Gains or losses each period are based on movements of forward commodity prices relative to the prices in our underlying financial derivative contracts.

Depreciation, depletion and amortization expense. During the quarter and nine months ended September 30, 2010, our depreciation, depletion and amortization expense increased compared with the same periods in 2009 as a result of a higher depletion rate and higher production volumes. The third quarter and nine months ended September 30, 2009 depletion rate was largely impacted by the ceiling test charges recorded in the first quarter of 2009, and we continue to experience a lower overall depletion rate in 2010 as a result of that charge. We expect our depreciation, depletion and amortization rate for the full year to be between $1.80/Mcfe and $1.85/Mcfe.

Production costs. During the quarter and nine months ended September 30, 2010, our production costs remained flat compared to the same periods in 2009 due to lower lease operating expenses offset by higher production taxes. Lease operating expenses were lower primarily due to a decrease in our domestic maintenance and repair expenses while the higher production taxes were as a result of higher natural gas and oil revenues.

Ceiling test charges. During the quarter and nine months ended September 30, 2010, we recorded non-cash ceiling test charges of $14 million and $16 million in our Egyptian full cost pool as a result of acreage relinquishments in South Mariut and South Alamein and a dry hole drilled in the Tanta block. During the quarter and nine months ended September 30, 2009, we recorded non-cash ceiling test charges of $5 million and $2.1 billion as a result of a dry hole drilled in the South Mariut block and low natural gas and oil prices.

Impairment of inventory. In the third quarter of 2009, we recorded a $16 million non-cash charge to reflect the market prices we expected to receive upon the sale of certain casing and tubular goods inventory (materials and supplies), which we intended to use in our capital programs.

Other. Our equity earnings from Four Star increased by $5 million and $26 million during the quarter and nine months ended September 30, 2010 as compared to the same periods in 2009 primarily due to the impact of higher commodity prices partially offset by lower production volumes.

Marketing Segment

Overview

Our Marketing segment s primary focus is to market our Exploration and Production segment s natural gas and oil production and to manage El Paso s overall price risk. In addition, we continue to manage and liquidate contracts which were primarily entered into prior to the deterioration of the energy trading environment in 2002. All of our remaining contracts are subject to counterparty credit and non-performance risks while our remaining mark-to-market contracts are also subject to interest rate exposure. Our contracts are described below and in further detail in our 2009 Annual Report on Form 10-K.

Power contracts. Prior to third quarter 2010, our primary unhedged exposure in the Marketing segment related to mark-to-market power contracts within the PJM region that extend through April 2016. During 2010, we entered into positions with a third party financial institution that eliminated the locational price risks associated with future volumes to be delivered under these contracts.

Transportation-related contracts. The impact of these accrual-based contracts is based on our ability to use or remarket the contracted pipeline capacity. These contracts require us to pay total annual demand charges of approximately $47 million in 2010 and an average of approximately $41 million per year between 2011 and 2014.

Natural gas contracts. As of September 30, 2010, we have long term gas supply contracts that obligate us to deliver natural gas to specified power plants. The accounting for these contracts is a combination of mark-to-market and accrual-based. These contracts are expected to have minimal future impact on this segment as we have substantially offset all of the fixed price exposure.

Operating Results

Our overall operating results and analysis for our Marketing segment during each of the quarters and nine months ended September 30 are as follows:

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(In millions)			
Income (Loss)				
Contracts Related to Legacy Trading Operations:				
Changes in fair value of power contracts	$ (13)	$ (6)	$ (34)	$ 49
Natural gas transportation-related contracts:				
Demand charges	(10)	(9)	(29)	(26)
Settlements, net of termination payments	10	3	26	15
Changes in fair value of natural gas contracts	(3)	(14)	(8)	4
Total revenues	(16)	(26)	(45)	42
Operating expenses, net	4	(2)		(8)
Other income			1	
EBIT	$ (12)	$ (28)	$ (44)	$ 34

During the quarters ended September 30, 2010 and 2009, and the nine months ended September 30, 2010, our results were primarily impacted by changes in the fair value of our legacy power contracts in PJM prior to entering into contracts that eliminated the locational price risks in this area. As a result of entering into those contracts, we expect the future earnings impact of the PJM contracts to be solely related to changes in interest rates and credit risk. Our results for the first nine months of 2009 were primarily driven by a $52 million mark-to-market gain related to the adoption of new accounting requirements for our derivative liabilities associated with non-cash collateral (e.g. letters of credit).

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Corporate and Other Expenses, Net

Our corporate and other activities include our general and administrative functions as well as our recently formed midstream business, our remaining power operations, and other miscellaneous businesses. The following is a summary of significant items impacting the EBIT in our corporate and other activities for the quarters and nine months ended September 30:

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(In millions)			
Income (Loss)				
Change in litigation, environmental and other reserves	$ (16)	$ (18)	$ (14)	$ 4
Equity earnings	2	(9)	13	(2)
Loss on sale of notes receivable				(22)
Loss on debt extinguishment	(104)		(104)	
Other	7	(1)	9	(1)
Total EBIT	$ (111)	$ (28)	$ (96)	$ (21)

Change in Litigation, Environmental, and Other Reserves. Our results for all periods presented were impacted by changes in certain legacy litigation and environmental remediation reserves and indemnification liabilities, including adjustments to environmental reserves associated with a non-operating chemical plant. Additionally impacting our results for the first nine months of 2009 were mark-to-market gains associated with an indemnification related to the sale of a legacy ammonia facility that fluctuates with ammonia prices. In the first half of 2010, we eliminated a significant portion of our exposure under this indemnification.

We have a number of pending litigation matters and reserves related to our historical business operations that 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.

Equity Earnings. During the quarters and nine months ended September 30, 2010 and 2009, our equity earnings (losses) were primarily from legacy power investments.

Loss on Sale of Notes Receivable. In the first quarter of 2009, we completed the sale of our investment in Porto Velho to our partner in the project for total consideration of $179 million, including $78 million in notes receivable. Subsequently, in the second quarter of 2009, we sold the notes, including accrued interest, to a third party financial institution for $57 million and recorded a loss of $22 million.

Loss on Debt Extinguishment. In September 2010, we exchanged approximately $348 million of our 12.00% Senior Notes due 2013 for cash and 6.50% Senior Notes due 2020. In conjunction with the transaction, we recorded a loss of $104 million.

Other. Our 2010 year-to-date EBIT was impacted by the refund of certain insurance premiums on legacy activities. In addition, during the quarter and nine months ended September 30, 2010, our EBIT was impacted by non-cash pension costs and other benefit costs related to legacy activities. Losses from our pension asset performance during 2008 will continue to be amortized into our future net benefit cost through 2011. Despite the increased expense, we do not anticipate making any contributions to our primary pension plan for the remainder of 2010. For further discussion of our primary pension plan and related net benefit cost, see our 2009 Annual Report on Form 10-K.

Interest and Debt Expense

Our interest and debt expense increased during the nine months ended September 30, 2010 as compared to the same period in 2009 primarily due to the Ruby term loan with GIP entered into in 2009 partially offset by higher AFUDC debt on the Ruby pipeline project. During the second quarter of 2010, the interest rate on the Ruby term loan also increased from 7 percent to 13 percent. In the third quarter of 2010, the Ruby term loan was converted to a convertible preferred equity interest in Ruby.

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Income Taxes

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(In millions, except for rates)			
Income taxes	$ 75	$ 35	$ 343	$ (425)
Effective tax rate	29%	30%	30%	35%

For a discussion of our effective tax rates and other matters impacting our income taxes, see Item 1, Financial Statements, Note 5.

Commitments and Contingencies

Below is a summary of certain climate change and energy policies recently enacted or proposed that, if enacted, will likely impact our business. For a further discussion of our commitments and contingencies, see Item 1, Financial Statements, Note 10, which is incorporated herein by reference.

Climate Change Legislation and Regulation. Legislative and regulatory efforts to address climate change and greenhouse gas (GHG) emissions are in various phases of discussions or implementation at international, federal, regional and state levels. We believe that legislation that either limits or sets a price on carbon emissions will increase demand for natural gas depending on the legislative provisions ultimately adopted. However, we also believe it is reasonably likely that the federal legislation being contemplated, as well as recently adopted and proposed federal regulations, would increase our cost of environmental compliance by requiring us to purchase emission allowances or offset credits, install additional equipment or change work practices, and could materially increase the cost of goods and services we purchase from suppliers due to their increased compliance costs. Although we believe that many of these costs should be recoverable in the rates charged by our pipelines and in the market price for natural gas that we sell, recovery through these mechanisms is still uncertain at this time.

The EPA has adopted regulations that require us to monitor and report certain GHG emissions from our operations on an annual basis. The EPA has proposed to further expand the monitoring and reporting requirements to additional natural gas transmission sources and to include onshore domestic exploration and production segments previously proposed to be exempt, which could materially increase the costs of our operations. Our preliminary estimate of the first-year cost to our company is approximately $11 million.

The EPA has also adopted regulations that will require permits to be obtained under the Clean Air Act for GHG emissions above certain thresholds. Depending on the thresholds ultimately established by the EPA, these permit requirements could have a material impact upon the costs of our operations, could require us to install new equipment to control emissions from our facilities and could result in delays and negative impacts on our ability to obtain permits and other regulatory approvals with regard to new and existing facilities. The EPA s regulations are being challenged in the federal courts; however, pending such judicial reviews, the thresholds that have been established by the EPA through at least 2016 are not expected to have a material impact on our operations or financial results.

It is uncertain what federal or state legislation or regulations will ultimately be adopted and whether adopted regulations will withstand likely legal challenges. Therefore, the potential impact on our operations and construction projects remains uncertain.

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 . Although it is reasonably likely that many of these proposals will be enacted over the next few years, we cannot predict the form of any laws and regulations that might be enacted, the timing of their implementation, or the precise impact on our operations or demand for natural gas. However, such proposals if enacted could impact natural gas demand over the longer term.

Air Quality Regulations. In February 2010, the EPA promulgated a new one-hour National Ambient Air Quality Standard (NAAQS) for oxides of nitrogen (NO2). The new standard is in addition to the existing annual NAAQS which was not changed. While it is uncertain how the EPA and the states will apply the new one-hour NAAQS, the new NAAQS may impact our ability to obtain permits and other regulatory approvals with regard to existing and new facilities and may cause us to incur costs to install additional controls on existing and new facilities. The EPA s new rule is being challenged in the federal courts. While the new NAAQS, if upheld, could have a material impact on our cost of operations and our cost to install new facilities, we are unable, at this point, to estimate its financial impact.

Liquidity and Capital Resources

During 2010, our primary focus from a liquidity perspective has been on funding our 2010 pipeline and exploration and production capital programs, meeting operating needs and repaying/repurchasing debt when due or when conditions warrant. Our primary sources of cash include cash flow from operations, funds provided through capital market activities (including executing our financing strategy utilizing EPB), bank credit facilities, project financings (such as Ruby) and asset sales where warranted. By June of this year, we had met our 2010 funding needs, and our activities for the remainder of the year are focused on meeting our 2011 funding objectives.

Available Liquidity and Liquidity Outlook for 2010. At September 30, 2010, our available liquidity was approximately $2.5 billion (approximately $0.3 billion cash and $2.2 billion of available credit facility), exclusive of combined cash and credit facility capacity under our EPB and Ruby credit facilities. Through September 30, 2010, we completed several funding actions including (i) the receipt of $1.2 billion in cash in conjunction with contributing ownership interests in SLNG, Elba Express and SNG to our MLP, which funded the acquisitions through the issuance of $0.5 billion of debt and the issuance of common units, (ii) the sale of certain of our interests in Mexican pipeline and compression assets for approximately $0.3 billion and (iii) borrowing approximately $362 million under our seven-year amortizing $1.5 billion Ruby financing facility that matures in 2017. In October 2010, we borrowed an additional $240 million under this Ruby facility. In September 2010, our MLP also issued approximately 13.2 million common units for net proceeds of approximately $0.4 billion which we anticipate will be used for potential future acquisitions and growth capital expenditures.

As further discussed in Item 1, Financial Statements, Notes 9 and 14, we entered into our Ruby pipeline project agreement with GIP in 2009 where they agreed to invest up to $700 million for a 50 percent equity interest in Ruby. As of September 30, 2010, GIP had funded $670 million related to the Ruby pipeline project, including $145 million for a convertible preferred equity interest in Ruby that was simultaneously exchanged for a convertible preferred equity interest in a holding company of Cheyenne Plains and $525 million in the form of a convertible preferred equity interest in Ruby. GIP will hold their interest in Cheyenne Plains until certain conditions are satisfied including placing the Ruby pipeline project in service. GIP has the right to convert its preferred equity in Ruby to common equity in Ruby at any time; however, the preferred equity is subject to mandatory conversion to Ruby common equity upon the satisfaction of certain conditions, including Ruby entering into additional firm transportation agreements. Our obligation to repay these amounts is secured by our equity interests in Ruby, Cheyenne Plains, and approximately 50 million common units we own in our MLP.

We began construction on our Ruby pipeline project in mid-2010 and currently expect that our Ruby pipeline project will be completed in June 2011, three months later than originally anticipated and approximately 10 to 15 percent over budget, primarily based on delays in obtaining regulatory clearances. Overall, however, we expect our aggregate multi-year pipeline expansion backlog to be within 5 percent of our original budgets. We have provided a contingent completion and cost-overrun guarantee to Ruby lenders; however, upon the Ruby pipeline project becoming operational and making certain permitting representations, the project financing will become non-recourse to us. Pursuant to the cost overrun guarantee to the Ruby lenders, we are required to post letters of credit for any forecasted cost overruns on the project approved by the lender s independent engineer. In this regard, we have posted $245 million in letters of credit to cover the anticipated cost overruns. If additional cost overruns are forecasted and approved by the lender s engineer in subsequent months, then additional letters of credit will be required to be issued pursuant to the Ruby financing agreements.

Our 2010 full year capital requirements, including our Ruby pipeline project, other pipeline projects and exploration and production expenditures have been significant; however, our 2011 requirements decline significantly, and by the end of 2011 most of our pipeline backlog will be placed in service. Our cash capital expenditures for the nine months ended September 30, 2010, and the amount of cash we expect to spend for the remainder of 2010 to grow and maintain our businesses are as follows:

	Nine Months Ended	2010

	September 30, 2010	Remaining	Total
	(In billions)		
Pipelines			
Maintenance	$ 0.2	$ 0.2	$ 0.4
Growth[1]	1.4	1.1	2.5
Exploration and Production [2]	1.0	0.3	1.3
Other	0.1		0.1
	$ 2.7	$ 1.6	$ 4.3

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

(2) Includes the leasehold acquisition of the Wolfcamp Shale during the third quarter of 2010.

We will continue to assess and take further actions where prudent to meet our long-term objectives and capital requirements, including considering additional opportunities with our MLP as the markets permit. There are a number of factors that could impact our plans, including our ability to access the financial markets to fund our long-term capital needs if the financial markets are restricted, or a further decline in commodity prices. If these events occur, additional adjustments to our plan and outlook may be required, including reductions in our discretionary capital program, further reductions in operating and general and administrative expenses, obtaining secured financing arrangements, seeking additional partners for other growth projects and the sale of additional non-core assets, all of which could impact our financial and operating performance.

Overview of 2010 Cash Flow Activities. During the first nine months of 2010, we generated operating cash flow of approximately $1.5 billion primarily from our pipeline and exploration and production operations. Cash flow from operations for the nine months ended September 30, 2010 was $0.3 billion lower than the same period in 2009 primarily due to lower 2010 realized commodity prices, including derivative contracts, compared with 2009 and working capital changes. We also generated approximately $0.3 billion from the sale of certain of our interests in Mexican pipeline and compression assets, approximately $1.0 billion as a result of the issuance of MLP common units and approximately $1.4 billion in debt proceeds including Ruby and other consolidated project financings as well as MLP debt offerings. We used the cash flow generated from these operating and financing activities to fund our capital programs, make net repayments under our various credit facilities and other debt obligations, and pay common and preferred dividends. For the nine months ended September 30, 2010, our cash flows from continuing operations are summarized as follows:

		2010 (In billions)
Cash Flow from Operations		
Operating activities		
Net income	$	0.8
Income adjustments		1.0
Change in assets and liabilities		(0.3)
Total cash flow from operations	$	1.5
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		1.4
Net proceeds from the issuance of noncontrolling interests		1.0
Net proceeds from the issuance of preferred stock in subsidiary		0.1
		2.5
Total other cash inflows	$	2.8
Cash Outflows		
Investing activities		

Capital expenditures	$	2.7
Financing activities		
Payments to retire long-term debt and other financing obligations		1.3
Dividends and other		0.1
		1.4
Total cash outflows	$	4.1
Net change in cash	$	0.2

Contractual Obligations

The following information provides updates to our contractual obligations, and should be read in conjunction with the information disclosed in our 2009 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, oil 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, 2010:

	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	$ 324	$ 115	$ (2)	$ 7	$ 444
Liabilities	(166)	(218)	(115)	(31)	(530)
Total commodity-based derivatives	$ 158	$ (103)	$ (117)	$ (24)	$ (86)

The following is a reconciliation of our commodity-based derivatives for the nine months ended September 30, 2010:

	Commodity-Based Derivatives (In millions)
Fair value of contracts outstanding at January 1, 2010	$ (381)
Fair value of contract settlements during the period[(1)]	(266)
Premiums during the period[(1)]	126
Changes in fair value of contracts during the period	435
Net changes in contracts outstanding during the period	295
Fair value of contracts outstanding at September 30, 2010	$ (86)

(1) Includes $119 million of non-cash transactions associated with exchanging certain of our 2011 natural gas collars for 2011 and 2012

natural gas fixed
price swaps.

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 2009 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 2009 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 our remaining forecasted 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 these 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 impacts on the 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 (liabilities)					
September 30, 2010	$ 368	$ 220	$ (148)	$ 515	$ 147
December 31, 2009	$ 127	$ (29)	$ (156)	$ 290	$ 163
Other commodity-based derivatives net assets (liabilities)					
September 30, 2010	$ (454)	$ (451)	$ 3	$ (456)	$ (2)
December 31, 2009	$ (508)	$ (517)	$ (9)	$ (500)	$ 8

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of September 30, 2010, 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 Securities Exchange Act of 1934, as amended (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, 2010.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the third quarter of 2010 that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

PART II OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Financial Statements, Note 10, which is incorporated herein by reference. Additional information about our legal proceedings can be found in Part I, Item 3 of our 2009 Annual Report on Form 10-K filed with the SEC.

Item 1A. Risk Factors

CAUTIONARY STATEMENTS FOR PURPOSES OF THE SAFE HARBOR PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

We have made statements in this document that constitute forward-looking statements, as that term is defined in the Private Securities Litigation Reform Act of 1995. Forward-looking statements include information concerning possible or assumed future results of operations. The words believe, expect, estimate, anticipate and similar expressions will generally identify forward-looking statements. These statements may relate to information or assumptions about:

- earnings per share;
- capital and other expenditures;
- dividends;
- financing plans;
- capital structure;
- liquidity and cash flow;
- pending legal proceedings, claims and governmental proceedings, including environmental matters;
- future economic and operating performance;
- operating income;
- management s plans; and
- goals and objectives for future operations.

Forward-looking statements are subject to risks and uncertainties. While we believe the assumptions or bases underlying the forward-looking statements are reasonable and are made in good faith, we caution that assumed facts or bases almost always vary from actual results, and these variances can be material, depending upon the circumstances. We cannot assure you that the statements of expectation or belief contained in our forward-looking statements will result or be achieved or accomplished. Important factors that could cause actual results to differ materially from estimates or projections contained in our forward-looking statements are described in our 2009 Annual Report on Form 10-K under Part I, Item 1A, Risk Factors. Below is an additional risk factor that may arise as a result of the oil spill in the Gulf of Mexico, as well as the recent financial reform legislation that was enacted in July 2010.

Our operations and financial results could be impacted by the oil spill in the Gulf of Mexico and recent incidents on third party pipelines, or by further developments in other potential regulatory, legislative or environmental initiatives.

The oil spill in the Gulf of Mexico poses additional risks for our exploration and production and pipeline businesses, including the possibility of (i) new environmental and safety review requirements imposed on drilling and/or development operations in the Gulf of Mexico and other areas, (ii) constrained industry access to the Gulf of Mexico, (iii) other indirect effects from the oil spill such as greater scrutiny and regulation of exploration and production operations, which may include delays in the receipt of necessary permits and approvals both in the U.S. and internationally, including our offshore exploration and production operations in Brazil and (iv) negative impacts on the availability and cost of insurance coverages applicable to offshore operations. While we have reduced our focus over the past several years in the Gulf of Mexico, any of these items could have an adverse impact on our strategy and profitability in both our domestic and international exploration and production operations and on supplies of natural gas from the Gulf of Mexico to certain of our pipeline systems. In addition, we have numerous contractual arrangements with many of the parties involved in the oil spill. Although in many cases the parties remain creditworthy or have posted credit support associated with these contractual arrangements, there is a risk that one or more of the parties could default in the performance of our contracts.

Several ruptures on third party pipelines have occurred recently. In response, various legislative and regulatory reforms associated with pipeline safety and integrity issues have been proposed, including reforms that would require increased periodic inspections, installation of additional valves and other equipment on our pipelines and subjecting additional pipelines (including gathering facilities) to more stringent regulation. It is uncertain what reforms, if any, will be adopted and what impact they might ultimately have on our operations or financial results.

In July 2010, federal legislation was enacted to implement various financial and governance reforms. Although many of the legislative provisions were focused on the financial and banking industries, portions of the legislation will impact our businesses. The extent of the impact is uncertain at this time, due to the requirement that various implementing regulations must be adopted by the SEC and the United States Commodity Futures Trading Commission (CFTC). For example, the legislation provides for the creation of certain position limits for derivative transactions, as well as certain exemptions from the general requirement that swap transactions must be cleared through a central exchange for which collateral must be posted. The CFTC must adopt regulations that define what position limits will be imposed and what swap transactions are entitled to such exemptions. Although we believe the derivative contracts that we enter into to hedge the commodity price risk associated with our natural gas and oil production should not be impacted by such position limits and should be exempt from the requirement to clear transactions through a central exchange or to post any collateral, the impact upon our businesses will depend on the outcome of the implementing regulations adopted by the CFTC.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. (Removed and Reserved)

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.

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 5, 2010

By: /s/ John R. Sult
John R. Sult
Executive Vice President and
Chief Financial Officer
(Principal Financial Officer)

Date: November 5, 2010

By: /s/ Francis C. Olmsted III
Francis C. Olmsted III
Vice President and Controller
(Principal Accounting Officer)

EL PASO CORPORATION
EXHIBIT INDEX

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

Exhibit Number	Description
4.A	Sixteenth Supplemental Indenture, dated as of September 24, 2010, between El Paso Corporation and HSBC Bank USA, National Association, as trustee, to Indenture dated as of May 10, 1999 (Exhibit 4.A to our Current Report on Form 8-K filed with the SEC on September 24, 2010).
10.A	Registration Rights Agreement dated September 24, 2010 (Exhibit 10.A to our Current Report on Form 8-K filed with the SEC on September 24, 2010).
*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.