EL PASO CORP/DE
Form 10-Q
November 07, 2011

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, 2011

OR

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

For the transition period from to

Commission File Number 1-14365

El Paso Corporation

(Exact Name of Registrant as Specified in Its Charter)

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

Telephone Number: (713) 420-2600

Internet Website: www.elpaso.com

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.:

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, 2011: 771,195,525

EL PASO CORPORATION
TABLE OF CONTENTS

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

/d	= per day
Bbl	= barrels
BBtu	= billion British thermal units
GW	= gigawatts
GWh	= gigawatt hours
LNG	= liquefied natural gas
MBbls	= thousand barrels
Mcf	= thousand cubic feet
Mcfe	= thousand cubic feet of natural gas equivalents
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 oil and natural gas 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/o subsidiaries.

Table of Contents

PART I FINANCIAL INFORMATION

Item 1. Financial Statements

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

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Operating revenues	$ 1,403	$ 1,213	$ 3,628	$ 3,632
Operating expenses				
Cost of products and services	44	57	135	163
Operation and maintenance	366	327	994	911
Loss on deconsolidation of subsidiary (Note 15)	600		600	
Ceiling test charges	152	14	152	16
Depreciation, depletion and amortization	299	239	815	699
Taxes, other than income taxes	63	58	217	181
	1,524	695	2,913	1,970
Operating income (loss)	(121)	518	715	1,662
Earnings from unconsolidated affiliates	36	28	98	167
Loss on debt extinguishment	(101)	(104)	(169)	(104)
Other income, net	5	71	186	188
Interest and debt expense	(242)	(255)	(721)	(782)
Income (loss) before income taxes	(423)	258	109	1,131
Income tax expense (benefit)	(130)	75	(73)	343
Net income (loss)	(293)	183	182	788
Net income attributable to noncontrolling interests	(75)	(41)	(226)	(101)
Net income (loss) attributable to El Paso Corporation	(368)	142	(44)	687
Preferred stock dividends of El Paso Corporation		9		28
Net income (loss) attributable to El Paso Corporation s common stockholders	$ (368)	$ 133	$ (44)	$ 659
Basic earnings per common share				
Net income (loss) attributable to El Paso Corporation s common stockholders	$ (0.48)	$ 0.19	$ (0.06)	$ 0.95
Diluted earnings per common share				
Net income (loss) attributable to El Paso Corporation s common stockholders	$ (0.48)	$ 0.19	$ (0.06)	$ 0.90

Dividends declared per El Paso Corporation s common share	$ 0.01	$ 0.01	$ 0.03	$ 0.03

See accompanying notes.

Table of Contents

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

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2011	**2010**	**2011**	**2010**
Net income (loss)	$ (293)	$ 183	$ 182	$ 788
Pension and postretirement obligations:				
Unrealized actuarial gains on postretirement benefit plans (net of income taxes of $6 and $6 in 2011)	13		13	
Reclassification of net actuarial losses during period (net of income taxes of $8 and $22 in 2011 and $6 and $18 in 2010)	15	11	46	35
Cash flow hedging activities:				
Unrealized mark-to-market losses arising during period (net of income taxes of $27 and $40 in 2011 and $20 and $45 in 2010)	(42)	(31)	(66)	(71)
Recognition of loss associated with interest rate swaps upon deconsolidation of subsidiary (net of income taxes of $46 and $46 in 2011)	79		79	
Reclassification adjustments for changes in initial value to the settlement date (net of income taxes of $6 and $8 in 2011 and $1 and $3 in 2010)	7	1	14	5
Other comprehensive income (loss)	72	(19)	86	(31)
Comprehensive income (loss)	(221)	164	268	757
Comprehensive loss attributable to noncontrolling interests	(79)	(41)	(230)	(101)
Comprehensive income (loss) attributable to El Paso Corporation	$ (300)	$ 123	$ 38	$ 656

See accompanying notes.

Table of Contents

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

	September 30, 2011	December 31, 2010
ASSETS		
Current assets		
Cash and cash equivalents (includes $31 in 2010 held by variable interest entities)	$ 390	$ 347
Accounts and notes receivable		
Customer, net of allowance of $4 in both 2011 and 2010	322	333
Affiliates	8	7
Other	165	160
Materials and supplies	167	169
Assets from price risk management activities	314	265
Deferred income taxes	107	165
Other	154	106
Total current assets	1,627	1,552
Property, plant and equipment, at cost		
Pipelines (includes $3,232 in 2010 held by variable interest entities)	19,771	22,385
Oil and natural gas properties, at full cost	21,556	21,692
Other	513	416
	41,840	44,493
Less accumulated depreciation, depletion and amortization	23,102	23,421
Total property, plant and equipment, net	18,738	21,072
Other long-term assets		
Investments in unconsolidated affiliates	2,756	1,673
Assets from price risk management activities	51	61
Other	906	912
	3,713	2,646
Total assets	$ 24,078	$ 25,270

See accompanying notes.

Table of Contents

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

	September 30, 2011	December 31, 2010
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 384	$ 610
Affiliates	11	9
Other	447	386
Short-term financing obligations, including current maturities	350	489
Liabilities from price risk management activities	152	176
Asset retirement obligations	62	63
Accrued interest	224	202
Other	612	630
Total current liabilities	2,242	2,565
Long-term financing obligations, less current maturities	12,531	13,517
Other long-term liabilities		
Liabilities from price risk management activities	271	397
Deferred income taxes	527	568
Other	1,352	1,461
	2,150	2,426
Commitments and contingencies (Note 10)		
Preferred stock of subsidiaries		698
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 as of December 31, 2010; stated at liquidation value		750
Common stock, par value $3 per share; authorized 1,500,000,000 shares; issued 785,546,406 shares in 2011 and 719,743,724 shares in 2010	2,357	2,159
Additional paid-in capital	5,449	4,484
Accumulated deficit	(2,478)	(2,434)
Accumulated other comprehensive loss	(669)	(751)
	(283)	(291)

Treasury stock (at cost); 15,063,780 shares in 2011 and 15,492,605 shares in 2010				
Total El Paso Corporation stockholders equity		4,376		3,917
Noncontrolling interests		2,779		2,147
Total equity		7,155		6,064
Total liabilities and equity	$	24,078	$	25,270

See accompanying notes.

Table of Contents

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

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Cash flows from operating activities		
Net income	$ 182	$ 788
Adjustments to reconcile net income to net cash from operating activities:		
Depreciation, depletion and amortization	815	699
Ceiling test charges	152	16
Loss on deconsolidation of subsidiary (Note 15)	600	
Deferred income tax expense (benefit)	(28)	339
Earnings from unconsolidated affiliates, adjusted for cash distributions	(50)	(115)
Loss on debt extinguishment	169	104
Other non-cash income items	(72)	(34)
Asset and liability changes	(151)	(385)
Net cash provided by operating activities	1,617	1,412
Cash flows from investing activities		
Capital expenditures	(2,989)	(2,641)
Cash paid for acquisitions, net of cash acquired	(2)	(25)
Net proceeds from the sale of assets and investments	592	332
Increase in notes receivable	(115)	(23)
Other	(69)	37
Net cash used in investing activities	(2,583)	(2,320)
Cash flows from financing activities		
Net proceeds from issuance of long-term debt	5,168	1,399
Payments to retire long-term debt and other financing obligations	(5,001)	(1,273)
Net proceeds from issuance of noncontrolling interests (Note 12)	948	956
Net proceeds from issuance of preferred stock of subsidiary	30	120
Dividends paid	(31)	(49)
Distributions to noncontrolling interest holders	(143)	(64)
Distributions to holders of preferred stock of subsidiary	(10)	(15)
Proceeds from stock option exercises	48	6
Other		2
Net cash provided by financing activities	1,009	1,082
Change in cash and cash equivalents	43	174
Cash and cash equivalents		

Beginning of period	347	635
End of period	$ 390	$ 809

See accompanying notes.

Table of Contents

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

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
El Paso Corporation stockholders equity:		
Preferred stock:		
Balance at beginning of period	$ 750	$ 750
Conversion of preferred stock	(750)	
Balance at end of period		750
Common stock:		
Balance at beginning of period	2,159	2,148
Conversion of preferred stock	174	
Other, net	24	11
Balance at end of period	2,357	2,159
Additional paid-in capital:		
Balance at beginning of period	4,484	4,501
Conversion of preferred stock	576	
Dividends	(22)	(49)
Issuances of noncontrolling interests (Note 12)	338	
Other, including stock-based compensation	73	32
Balance at end of period	5,449	4,484
Accumulated deficit:		
Balance at beginning of period	(2,434)	(3,192)
Net income (loss) attributable to El Paso Corporation	(44)	687
Balance at end of period	(2,478)	(2,505)
Accumulated other comprehensive income (loss):		
Balance at beginning of period	(751)	(718)
Other comprehensive income (loss) attributable to noncontrolling interests	82	(31)
Balance at end of period	(669)	(749)
Treasury stock, at cost:		
Balance at beginning of period	(291)	(283)
Stock-based and other compensation	8	(7)
Balance at end of period	(283)	(290)

Total El Paso Corporation stockholders equity at end of period	4,376	3,849
Noncontrolling interests:		
Balance at beginning of period	2,147	785
Issuance of noncontrolling interests (Note 12)	610	956
Distributions to noncontrolling interests	(143)	(64)
Net income attributable to noncontrolling interests (Note 12)	161	75
Other comprehensive income attributable to noncontrolling interests	4	
Balance at end of period	2,779	1,752
Total equity at end of period	$ 7,155	$ 5,601

See accompanying notes.

6

Table of Contents

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

1. Basis of Presentation and Significant Accounting Policies

Basis of Presentation

We prepared this Quarterly Report on Form 10-Q under the rules and regulations of the United States Securities and Exchange Commission (SEC). As 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) and should be read along with our 2010 Annual Report on Form 10-K. The financial statements as of September 30, 2011, and for the quarters and nine months ended September 30, 2011 and 2010, are unaudited. The condensed consolidated balance sheet as of December 31, 2010 was derived from the audited balance sheet filed in our 2010 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. Our financial statements for prior periods include reclassifications that were made to conform to the current year presentation, none of which impacted our reported net income or stockholders equity. Additionally, our statement of cash flows for the nine months ended September 30, 2010 reflects a decrease in both net cash provided by operating activities and net cash used in investing activities related to the timing of certain capital expenditures which was considered immaterial to our 2010 consolidated financial statements. Due to the seasonal nature of our businesses, information for interim periods may not be indicative of our operating results for the entire year. Our disclosures in this Form 10-Q are an update to those provided in our 2010 Annual Report on Form 10-K.

On October 16, 2011, we announced a definitive agreement with Kinder Morgan, Inc. (KMI) whereby KMI will acquire El Paso Corporation (El Paso) in a transaction that values El Paso at approximately $38 billion, including the assumption of debt. The transaction has been approved by each of our and KMI s board of directors. The completion of the transaction is subject to satisfaction or waiver of certain closing conditions including, among others, customary regulatory approvals, approval of the transaction by our stockholders and approval of the issuance of KMI stock and warrants by KMI s stockholders. A voting agreement has been executed by certain stockholders of KMI, holding approximately 75% of the voting power of KMI, in which such stockholders have agreed to vote in favor of the merger and issuance of KMI stock and warrants. The completion of the merger will constitute a change of control for El Paso that may trigger change in control provisions in certain agreements (e.g., debt) to which we are a party. KMI has announced that they intend to sell our exploration and production assets and as such, we will no longer pursue the tax-free spin-off of our exploration and production business into a new publicly traded company.

Upon the merger, El Paso shareholders will receive a combination of Class P shares of common stock of KMI, common stock purchase warrants of KMI and cash. Each share of El Paso common stock (excluding any shares held by KMI or its subsidiaries or by El Paso and dissenting shares in accordance with Delaware law), will, at the effective time of the merger, be converted into the right to receive, at the election of the holder but subject to pro-ration with respect to the stock and cash portion such that approximately 57% of the aggregate merger consideration (excluding the warrants) is paid in cash and approximately 43% (excluding the warrants) is paid in Class P common stock of KMI, par value $0.01 per share (the KMI Class P Common Stock): (i) 0.9635 of a share of KMI Class P Common Stock and 0.640 of a common stock purchase warrant of KMI (a KMI Warrant), (ii) $25.91 in cash without interest and 0.640 of a KMI Warrant or (iii) 0.4187 of a share of KMI Class P Common Stock, $14.65 in cash without interest and 0.640 of a KMI Warrant. Each KMI Warrant will entitle its holder to purchase one share of KMI Class P Common Stock at an exercise price of $40.00 per share, subject to certain adjustments, at any time during the five-year period following the closing of the merger.

Significant Accounting Policies

There were no changes in the significant accounting policies described in our 2010 Annual Report on Form 10-K and no significant accounting pronouncements issued but not yet adopted as of September 30, 2011.

2. Divestitures

During 2011, we sold non-core oil and natural gas properties located in our Central, Western and Southern divisions in several transactions from which we received proceeds that totaled approximately $570 million. During 2010, we also sold non-core natural gas producing properties located in our Southern division for approximately $22 million. No gain or loss was recorded on the sale of the oil and gas properties in either year. Additionally, during the nine months ended September 30, 2010 we 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.

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, 2011 and 2010, we recorded the following ceiling test charges:

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(In millions)			
Full cost pool:				
Brazil	$ 152	$	$ 152	$
Egypt		14		16
Total	$ 152	$ 14	$ 152	$ 16

Our Brazilian charge was driven, in part, by the release of certain unevaluated costs into the Brazilian full cost pool primarily as a result of the recent denial of a necessary environmental permit. See Note 8 for a further discussion. We may incur additional ceiling test charges in Brazil in the future depending on the value of our proved reserves, which are subject to change as a result of factors such as prices, costs and well performance. Additionally, we may incur ceiling test charges in Egypt depending on the results of our activities in that country.

4. Other Income, Net

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

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(In millions)			
Other Income, Net				
Allowance for equity funds used during construction	$ 16	$ 55	$ 187	$ 156
Other	(11)	16	(1)	32
Total	$ 5	$ 71	$ 186	$ 188

Allowance for Equity Funds Used During Construction. As allowed by the Federal Energy Regulatory Commission (FERC), we capitalize 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.

5. Income Taxes

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

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(In millions, except rates)			
Income tax expense (benefit)	$ (130)	$ 75	$ (73)	$ 343
Effective tax rate	31%	29%	(67)%	30%

Table of Contents

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 in which they occur. Changes in tax laws or rates are recorded in the period of enactment. Our effective tax rate is primarily impacted 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 ended September 30, 2011, our effective tax rate was significantly impacted by income attributable to nontaxable noncontrolling interests and a Brazilian ceiling test charge without a corresponding U.S. or Brazilian tax benefit (deferred tax benefits related to the Brazilian ceiling test charge were offset by an equal valuation allowance).

For the nine months ended September 30, 2011, our income taxes included in net income differs from the amount computed by applying the statutory federal income tax rate of 35 percent for the following reasons:

		September 30, 2011 (In millions, except rates)
Income taxes at the statutory federal rate of 35%	$	38
Increase (decrease)		
Income attributable to nontaxable noncontrolling interests		(92)
Foreign income taxed at different rates		45
State income taxes, net of federal income tax effect		(31)
Earnings from unconsolidated affiliates where we anticipate receiving dividends		(29)
Other		(4)
Income tax expense (benefit)	$	(73)
Effective tax rate		(67)%

Foreign income taxed at different rates in the table above includes $53 million related to the impact of the Brazilian ceiling test charge without a corresponding U.S. or Brazilian tax benefit (deferred tax benefits related to the Brazilian ceiling test charge were offset by an equal valuation allowance) and the favorable resolution of certain tax matters in the first half of 2011. *State income taxes, net of federal income tax effect* in the table above includes the state tax benefit associated with the third quarter non-cash loss on the deconsolidation of Ruby (see Note 15) and the favorable resolution of certain tax matters in the first half of 2011.

In the fourth quarter of 2011, we will record a significant deferred state tax benefit of approximately $65 million due to an expected reduction to state tax rates as a result of a conversion of a subsidiary to a limited liability company on October 1, 2011.

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 of 2010 from healthcare legislation enacted in March 2010.

Unrecognized Tax Benefits. We believe it is reasonably possible that the total amount of unrecognized tax benefits (including interest and penalty) could decrease by as much as $70 million over the next 12 months as a result of the anticipated favorable resolution of certain tax matters.

Table of Contents

6. Earnings Per Share

Basic and diluted earnings per common share were as follows for the quarters and nine months ended September 30:

Quarters Ended September 30,

	2011		2010	
	Basic	Diluted	Basic	Diluted
	(In millions, except per share amounts)			
Net income (loss) attributable to El Paso Corporation	$ (368)	$ (368)	$ 142	$ 142
Preferred stock dividends of El Paso Corporation			(9)	
Net income (loss) attributable to El Paso Corporation s common stockholders	$ (368)	$ (368)	$ 133	$ 142
Weighted average common shares outstanding	764	764	699	699
Effect of dilutive securities:				
Options and restricted stock				5
Convertible preferred stock				58
Weighted average common shares outstanding and dilutive securities	764	764	699	762
Basic and diluted earnings (loss) per common share:				
Net income (loss) attributable to El Paso Corporation s common stockholders	$ (0.48)	$ (0.48)	$ 0.19	$ 0.19

Table of Contents

Nine Months Ended September 30,

	2011		2010	
	Basic	Diluted	Basic	Diluted
	(In millions, except per share amounts)			
Net income (loss) attributable to El Paso Corporation	$ (44)	$ (44)	$ 687	$ 687
Preferred stock dividends of El Paso Corporation			(28)	
Net income (loss) attributable to El Paso Corporation s common stockholders	$ (44)	$ (44)	$ 659	$ 687
Weighted average common shares outstanding	747	747	698	698
Effect of dilutive securities:				
Options and restricted stock				5
Convertible preferred stock				58
Weighted average common shares outstanding and dilutive securities	747	747	698	761
Basic and diluted earnings (loss) per common share:				
Net income (loss) attributable to El Paso Corporation s common stockholders	$ (0.06)	$ (0.06)	$ 0.95	$ 0.90

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. Our potentially dilutive securities consist of employee stock options, restricted stock, trust preferred securities and convertible preferred stock. In March 2011, we converted our preferred stock to common stock as further described in Note 12. For the quarters and nine months ended September 30, 2011, we incurred losses attributable to El Paso Corporation and, accordingly, excluded all potentially dilutive securities from the determination of diluted earnings per share. For the quarter and nine months ended September 30, 2010, certain of our employee stock options and our trust preferred securities were antidilutive.

Table of Contents

7. Financial Instruments

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

	September 30, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Long-term financing obligations, including current maturities	$ 12,881	$ 14,230	$ 14,006	$ 14,686
Marketable securities in non-qualified compensation plans	20	20	20	20
Commodity-based derivatives	(45)	(45)	(186)	(186)
Interest rate derivatives	(13)	(13)	(61)	(61)
Other	(11)	(11)	(11)	(11)

As of September 30, 2011 and December 31, 2010, the carrying amounts of cash and cash equivalents, accounts receivable, accounts payable and short-term financing obligations represent 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 our long-term financing obligations based on quoted market prices for the same or similar issuances, including consideration of our credit risk related to those instruments.

Our derivative financial instruments are further described in our 2010 Annual Report on Form 10-K and below:

Production-Related Commodity Based Derivatives. As of September 30, 2011 and December 31, 2010, we have production-related derivatives (oil and natural gas swaps, collars, basis swaps and option contracts) to mitigate a portion of our commodity price risk and stabilize cash flows associated with forecasted sales of oil and natural gas production on 15,956 MBbl and 12,240 MBbl of oil and 149 TBtu and 283 TBtu of natural gas. None of these contracts are designated as accounting hedges.

Other Commodity-Based Derivatives. As of September 30, 2011 and December 31, 2010, in our Marketing segment we have forwards, swaps and options contracts related to long-term natural gas and power. These contracts, the longest of which extends into 2019, include (i) obligations to sell natural gas to power plants ranging from 12,550 MMBtu/d to 95,000 MMBtu/d and (ii) an obligation 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 1,700 to 3,700 GWh, to provide annually approximately 1,700 GWh of power and approximately 71 GW of installed capacity in the PJM power pool. We have entered into contracts to economically mitigate our exposure to commodity price changes and locational price differences on substantially all of these natural gas and power volumes. None of these derivatives are designated as accounting hedges.

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, 2011 and December 31, 2010, we had interest rate swaps that are designated as cash flow hedges that effectively convert the interest rate on approximately $0.2 billion and $1.3 billion of debt from a floating LIBOR interest rate to a fixed interest rate. The majority of the balance at December 31, 2010 related to interest rate swaps on $1.1 billion of Ruby debt. These hedges began accruing interest on June 30, 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. In connection with the deconsolidation of Ruby, these interest rate swaps and the related accumulated other comprehensive loss are no longer reflected on our balance sheet. For a further discussion of Ruby, see Note 15.

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 designated as fair value hedges 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 which is offset by changes in the fair value of the related hedged items. As of September 30, 2011 and December 31, 2010, these interest rate swaps converted the interest rate on approximately $162 million and $184 million of debt from a fixed rate to a variable rate of LIBOR plus 4.18%.

Table of Contents

Fair Value Measurement. We separate the fair values of our financial instruments 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 and classification of an instrument within a level can change over time based on the maturity or liquidity of the instrument. During the quarter and nine months ended September 30, 2011, there have been no changes to the inputs and valuation techniques used to measure fair value, the types of instruments, or the levels in which they are classified. Our marketable securities in non-qualified compensation plans and other are reflected at fair value on our balance sheets as other long-term assets, other current liabilities and other long-term liabilities. We net our derivative assets and liabilities for counterparties where we have a legal right of offset and classify our derivatives as either current or non-current assets or liabilities based on their anticipated settlement date. At September 30, 2011 and December 31, 2010, cash collateral held was not material. The following table presents the fair value of our financial instruments at September 30, 2011 and December 31, 2010 (in millions).

	September 30, 2011				December 31, 2010			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
Commodity-based derivatives								
Production-related oil and natural gas derivatives	$	$ 379	$	$ 379	$	$ 373	$	$ 373
Other natural gas derivatives		74	16	90		139	18	157
Power-related derivatives			16	16			31	31
Total commodity-based derivative assets		453	32	485		512	49	561
Interest rate derivatives designated as hedges								
Fair value hedges		3		3		8		8
Impact of master netting arrangements		(113)	(10)	(123)		(229)	(14)	(243)
Total price risk management assets	$	$ 343	$ 22	$ 365	$	$ 291	$ 35	$ 326
Marketable securities in non-qualified compensation plans	20			20	20			20
Total net assets	$ 20	$ 343	$ 22	$ 385	$ 20	$ 291	$ 35	$ 346
Liabilities								
Commodity-based derivatives								
	$	$ (83)	$	$ (83)	$	$ (136)	$	$ (136)

Production-related oil and natural gas derivatives								
Other natural gas derivatives		(88)	(56)	(144)		(162)	(90)	(252)
Power-related derivatives			(303)	(303)			(359)	(359)
Total commodity-based derivative liabilities		(171)	(359)	(530)		(298)	(449)	(747)
Interest rate derivatives designated as hedges								
Cash flow hedges		(16)		(16)		(69)		(69)
Impact of master netting arrangements		113	10	123		229	14	243
Total price risk management liabilities	$	$ (74)	$ (349)	$ (423)	$	$ (138)	$ (435)	$ (573)
Other			(12)	(12)			(12)	(12)
Total net liabilities	$	$ (74)	$ (361)	$ (435)	$	$ (138)	$ (447)	$ (585)
Total	$ 20	$ 269	$ (339)	$ (50)	$ 20	$ 153	$ (412)	$ (239)

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. Based on our assessment of counterparty risk in light of the collateral our counterparties have posted with us (primarily in the form of letters of credit), we have determined that our exposure is primarily related to our production-related derivatives and is limited to ten financial institutions, each of which has a current Standard & Poor s credit rating of A or better.

Table of Contents

The following table presents the changes in our financial assets and liabilities included in Level 3 for the quarter and nine months ended September 30, 2011:

	Balance at Beginning of Period	Change in Fair Value Reflected in Operating Revenues[1]	Change in Fair Value Reflected in Operating Expenses[2]	Settlements	Balance at End of Period
			(In millions)		
Quarter Ended September 30, 2011					
Assets	$ 28	$ (5)	$	$ (1)	$ 22
Liabilities	(396)	4	(1)	32	(361)
Total	$ (368)	$ (1)	$ (1)	$ 31	$ (339)
Nine Months Ended September 30, 2011					
Assets	$ 35	$ (11)	$	$ (2)	$ 22
Liabilities	(447)	1	(7)	92	(361)
Total	$ (412)	$ (10)	$ (7)	$ 90	$ (339)

(1) Includes approximately $1 million and $10 million of net losses that had not been realized through settlements for the quarter and nine months ended September 30, 2011.

(2) Includes approximately $1 million and $5 million of net losses that had not been realized through settlements for the quarter and nine months ended September 30, 2011.

Below are the impacts of our commodity-based and interest rate derivatives to our statements of income and statements of comprehensive income for the quarters and nine months ended September 30:

	2011			2010		
	Operating Revenues	Interest Expense	Other Comprehensive Income (Loss)	Operating Revenues	Interest Expense	Other Comprehensive Income (Loss)
			(In millions)			
Quarters ended September 30,						
Production-related derivatives	$ 251	$	$ 2	$ 184	$	$ 2
Other natural gas and power derivatives	(1)			(14)		
Total interest rate derivatives		12	84(1)		4	(43)

Total	$	250	$	12	$	86	$	170	$	4	$	(41)
Nine months ended September 30,												
Production-related derivatives	$	274	$		$	8	$	468	$		$	8
Other natural gas and power derivatives		(8)						(40)				
Total interest rate derivatives				20		53(1)				13		(89)
Total	$	266	$	20	$	61	$	428	$	13	$	(81)

(1) Includes $125 million related to the recognition of the accumulated other comprehensive loss associated with interest rate swaps on Ruby s debt in conjunction with its deconsolidation (see Note 15) included in Loss on deconsolidation of subsidiary in the condensed consolidated statements of income.

Table of Contents

8. Property, Plant and Equipment

Unevaluated capitalized costs of oil and natural gas operations were as follows:

	September 30, 2011	December 31, 2010
	(In millions)	
U.S.		
Acquisition	$ 338	$ 407
Exploration	119	130
Total U.S	457	537
Brazil & Egypt		
Acquisition	34	45
Exploration	45	203
Total Brazil & Egypt	79	248
Worldwide	$ 536	$ 785

During the quarter and nine months ended September 30, 2011, we released approximately $42 million and $86 million of our unevaluated capitalized costs to our Brazilian full cost pool upon the completion of our evaluation of certain exploratory wells drilled in 2009 and 2010. During the third quarter of 2011, we also released approximately $94 million related to a certain Brazilian development project where we were recently denied a necessary environmental permit. These actions contributed to a ceiling test charge recorded on the Brazilian full cost pool during the third quarter of 2011. See Note 3 for a further discussion. At September 30, 2011, we have total oil and natural gas capitalized costs of approximately $207 million and $71 million in Brazil and Egypt, of which $8 million and $71 million are unevaluated capitalized costs.

Table of Contents

9. Debt, Other Financing Obligations and Other Credit Facilities

	September 30, 2011	December 31, 2010
	(In millions)	
Short-term financing obligations, including current maturities	$ 350	$ 489
Long-term financing obligations	12,531	13,517
Total	$ 12,881	$ 14,006

Changes in Financing Obligations. During the nine months ended September 30, 2011, we had the following changes in our financing obligations:

Company	Interest Rate	Book Value Increase (Decrease)	Cash Received (Paid)
		(In millions)	
Issuances			
Ruby Pipeline, L.L.C. credit facility	variable	$ 393	$ 393
Southern Natural Gas Company, L.L.C. (SNG) notes due 2021	4.40%	300	297
EP Energy Corporation (EPE) revolving credit facility	variable	1,425	1,418
El Paso revolving credit facilities	variable	1,619	1,610
El Paso Pipeline Partners Operating Company, L.L.C. (EPPOC) revolving credit facility	variable	965	958
EPPOC notes due 2021	5.00%	497	492
Increases through September 30, 2011		$ 5,199	$ 5,168
Repayments, repurchases, and other			
EPE revolving credit facility	variable	$ (1,175)	$ (1,175)
El Paso revolving credit facilities	variable	(1,046)	(1,046)
EPPOC revolving credit facility	variable	(1,235)	(1,235)
EPPOC notes due 2011	7.76%	(37)	(37)
El Paso notes due 2011	7.00% 7.625%	(332)	(332)
El Paso notes due 2012 through 2037	6.875% 12.00%	(999)	(1,159)
Ruby Pipeline, L.L.C. credit facility[1]	variable	(1,487)	
Other	various	(13)	(17)
Decreases through September 30, 2011		$ (6,324)	$ (5,001)

(1) In September 2011, the Ruby debt obligations became non-recourse to us and we deconsolidated Ruby. As a result, we no longer reflect the debt obligations or related interest rate swaps on our balance sheet (see Note 15).

Repurchase of Senior Notes. During the nine months ended September, 30, 2011, we repurchased approximately $1.0 billion of our senior unsecured notes. In conjunction with these transactions, we recorded total losses on debt extinguishment of $101 million and $169 million during the quarter and nine months ended September 30, 2011. In

September 2010, we exchanged debt with a principal value of approximately $348 million. In conjunction with this transaction we recorded a loss of $104 million consisting of $77 million of cash consideration paid to the holders of the senior notes and $27 million to write-off unamortized discount and debt issue costs.

Refinancing of Revolving Credit Facilities. During the second quarter of 2011, we refinanced $3.25 billion in revolving credit facilities to extend their maturity to 2016. As part of the revolver refinancings, we reduced the overall borrowing capacity on the El Paso facility from $1.5 billion to $1.25 billion and increased the overall borrowing capacity on the EPPOC facility from $0.75 billion to $1.0 billion (expandable to $1.5 billion for certain expansion projects and acquisitions). Our current cost to borrow under the facilities has increased to LIBOR plus 2.25 for El Paso, LIBOR plus 2.00 for EPPOC and LIBOR plus 1.50 to 2.50 for EPE. The El Paso facility collateral support now includes the general partnership interests in El Paso Pipeline Partners, L.P. (EPB) while certain collateral restrictions have been modified providing us the ability to sell up to 100 percent of our ownership interests in either El Paso Natural Gas Company (EPNG) or Tennessee Gas Pipeline Company, L.L.C. (TGP), or some combination thereof, to EPB. Upon achieving investment grade status by one of the rating agencies, collateral support on the El Paso facility will be eliminated. As of September 30, 2011, we were in compliance with all of our debt covenants of which there were no material changes from those reported in our 2010 Annual Report on Form 10-K.

Credit Facilities/Letters of Credit. We have various credit facilities in place, including the above revolvers, which allow us to borrow funds or issue letters of credit. During the first nine months of 2011, we increased the total letter of credit capacity under certain existing and new letter of credit facilities by $175 million with a weighted average fixed facility fee of 1.78 percent and maturities ranging from April 2012 to September 2014. In July 2011, our $500 million unsecured credit facility matured. As of September 30, 2011, the aggregate amount outstanding under all of our credit facilities was $1.3 billion in addition to $0.6 billion of letters of credit and surety bonds, including $0.4 billion related to our price risk management activities. Our total available capacity under all of our facilities was approximately $1.3 billion as of September 30, 2011 (not including capacity available under the EPPOC $1.0 billion revolving credit facility).

10. Commitments and Contingencies

Legal Proceedings

Shareholder Class Actions. Beginning on October 17, 2011, multiple purported shareholder class actions were filed challenging the proposed acquisition of El Paso by KMI. The lawsuits were filed against both companies, an advisor and the El Paso board of directors. The shareholder class actions generally allege that the El Paso board breached its fiduciary duties to the shareholders by approving the transaction and that the two companies aided in the alleged breach. All of the shareholder class actions seek to enjoin the transaction. These actions have been filed in state district court in Harris County, Texas, and in Delaware Chancery Court. We expect that additional actions may be filed in the future. We believe these purported shareholder class actions are without merit and we intend to defend against them vigorously.

Cash Balance Plan Lawsuit. In December 2004, a purported class action lawsuit entitled *Tomlinson, et al.v. El Paso Corporation and El Paso Corporation Pension Plan* was filed in U.S. District Court for Denver, Colorado. The lawsuit alleges various violations of the Employee Retirement Income Security Act (ERISA) and the Age Discrimination in Employment Act as a result of our change from a final average earnings formula pension plan to a cash balance pension plan. In 2010, a District Court dismissed all of the claims in this matter. The plaintiffs appealed the dismissal of the case and in August 2011 the Court of Appeals for the Tenth Circuit affirmed the District Court s decision. We believe that it is likely that the plaintiffs will seek United States Supreme Court review of the Tenth Circuit decision.

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. Several of the cases have been settled or dismissed. The remaining cases, which were pending in Nevada, were dismissed. Appeals have been filed. Although damages in excess of $140 million have been alleged in total against all defendants in one of the remaining lawsuits where a damage number is provided, there remains significant uncertainty regarding the validity of the causes of action, the damages asserted and the level of damages, if any, that may be allocated to us. Therefore, 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 against us and many other defendants, including remedial activities, damages, attorneys fees and costs. These cases were initially consolidated for pre-trial purposes in multi-district litigation (MDL) in the U.S. District Court for the Southern District of New York. Several cases were later remanded to state court. Eighty-eight of the cases have been settled or dismissed, and all of the settlements have been or are expected to be substantially funded by insurance. We have eleven remaining lawsuits, all pending in the MDL. Of these remaining lawsuits, it is likely that our insurers will assert denial of coverage on nine of the most-recently filed lawsuits. Based upon discovery conducted to date, our share of the relevant markets upon which alleged damages have been historically allocated among individual defendants is relatively small. In addition, there remains significant uncertainty regarding the validity of the causes of action, the damages asserted and the level of damages, if any, that may be allocated to us as well as availability of insurance coverages. Therefore, 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 lawsuits and governmental proceedings and claims that arise in the ordinary course of our business. 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, 2011, we had approximately $40 million accrued, which has not been reduced by $2 million of related insurance receivables, for all of our outstanding legal proceedings.

Rates and Regulatory Matters

EPNG Rate Case. In April 2010, the FERC approved an offer of settlement which increased EPNG s base tariff rates, effective January 1, 2009. As part of the settlement, EPNG made refunds to its customers in 2010. The settlement resolved all but four issues in the rate proceeding. In January 2011, the Presiding Administrative Law Judge issued a decision that for the most part found against EPNG on the four issues. EPNG has appealed those decisions to the FERC and may also seek review of any of the FERC s decisions to the U.S. Court of Appeals. Although the final 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 which 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. A hearing commenced in late October 2011. It is uncertain whether the requested increase will be achieved in the context of any settlement between EPNG and its customers or following the outcome of a hearing in the rate case. Although the final outcome is not currently determinable, we believe our accruals established for this matter are adequate.

TGP Rate Case. In November 2010, TGP filed a rate case with the FERC proposing an increase in its base tariff rates and the implementation of a fuel volume tracker with a reduction in TGP s fuel retention rates, among other things. In December 2010, the FERC issued an order accepting and suspending the effective date of the proposed rates to June 1, 2011, subject to refund, the outcome of a hearing and other proceedings. In September 2011, TGP filed a proposed settlement with the FERC, which was uncontested by its customers. The proposed settlement provides for, among other things, an increase in TGP s revenues of approximately $60 million to $70 million annually, net of revenues from excess fuel retention, significant contract extensions until October 2014 and a requirement to file new rates to be effective no earlier than April 2014 but no later than November 2015. Although the FERC has not yet approved the proposed settlement, we believe our accruals established for this matter are adequate.

Colorado Interstate Gas Company, L.L.C. (CIG) Rate Case. In August 2011, the FERC approved an uncontested pre-filing settlement of CIG s rate case required under the terms of a previous settlement. The settlement generally provides for CIG s current tariff rates to continue until its next general rate case which will be effective after October 1, 2014 but no later than October 1, 2016.

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, 2011, our accrual was approximately $186 million for environmental matters, which has not been reduced by $19 million for amounts to be paid directly under government sponsored programs or through contractual arrangements with third parties. Our accrual includes approximately $183 million for expected remediation costs and associated onsite, offsite and groundwater technical studies and approximately $3 million for related environmental legal costs.

Table of Contents

Our estimates of potential liability range from approximately $186 million to approximately $327 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:

Sites	September 30, 2011 Expected	September 30, 2011 High
	(In millions)	
Operating	$ 8	$ 12
Non-operating.	164	279
Superfund	14	36
Total	$ 186	$ 327

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 28 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 matters are included in the previously indicated estimates for Superfund sites.

For the remainder of 2011, we estimate that our total remediation expenditures will be approximately $20 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 $27 million in the aggregate for the remainder of 2011 through 2015, including capital expenditures associated with the impact of the Environmental Protection Agency rule on emissions of hazardous air pollutants from reciprocating internal combustion engines which are subject to regulations with which we 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 have guarantees and indemnifications with a maximum stated value of approximately $0.7 billion, primarily related to indemnification arrangements associated with the sale of ANR Pipeline Company in 2007 and certain legacy assets. These amounts exclude guarantees for which we have issued related letters of credit discussed in Note 9. 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, 2011, we have recorded obligations of $17 million related to our guarantee and indemnification arrangements. 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.

For a further discussion of our guarantees, indemnifications, purchase obligations, and other commercial commitments see our 2010 Annual Report on Form 10-K.

11. Retirement Benefits

Components of Net Benefit Cost. The components of net benefit cost are as follows for the quarters and nine months ended September 30:

	Quarters Ended September 30,				Nine Months Ended September 30,			
	Pension Benefits		Other Postretirement Benefits		Pension Benefits		Other Postretirement Benefits	
	2011	2010	2011	2010	2011	2010	2011	2010
	(In millions)							
Service cost	$ 5	$ 5	$	$	$ 16	$ 14	$	$
Interest cost	27	29	8	8	80	86	23	25
Expected return on plan assets	(36)	(39)	(4)	(3)	(109)	(118)	(11)	(10)
Amortization of net actuarial loss (gain)	23	18			69	55	(1)	(2)
Amortization of prior service cost (credit)				(1)		1		(1)
Net benefit cost	$ 19	$ 13	$ 4	$ 4	$ 56	$ 38	$ 11	$ 12

12. Equity and Noncontrolling Interests

Convertible Perpetual Preferred Stock. In March 2011, we exercised our mandatory conversion right related to our $750 million of convertible perpetual preferred stock. Upon conversion, holders of our convertible preferred stock received approximately 57.9 million shares of common stock (approximately 77.2295 shares of El Paso common stock for each share of preferred stock converted).

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 for the nine months ended September 30, 2011	$ 22	$ 9
Amount paid in October 2011	$ 7	$
Declared in October 2011:		
Date of declaration	October 6, 2011	
Payable to shareholders on record	December 2, 2011	
Date payable	January 3, 2012	

Dividends on our common stock and convertible preferred stock are treated as a reduction of additional paid-in-capital since we currently have an accumulated deficit. For 2011, 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 2010 Annual Report on Form 10-K.

Noncontrolling Interests in EPB. We are the general partner of EPB, a master limited partnership (MLP) formed in 2007. As of September 30, 2011, we own a 44 percent interest in EPB (2 percent general partner interest and a 42 percent limited partner interest). During the first nine months of 2011, we contributed the remaining 40 percent ownership interest in SNG and an additional 28 percent interest in CIG to EPB in exchange for approximately $1.4 billion. EPB raised the funds for the acquisitions primarily through $948 million in proceeds from the issuance of 28.5 million common units and $444 million in borrowings under the EPPOC revolving credit facility. Our consolidated statement of equity for the nine months ended September 30, 2011 reflects the issuance of the EPB common units as an increase of $610 million to noncontrolling interests and an increase of $338 million to El Paso Corporation s additional paid-in capital. Our net income attributable to El Paso Corporation, together with the increase in El Paso Corporation s additional paid-in capital for the nine months ended September 30, 2011 totaled $294 million.

In accordance with its partnership agreement, EPB is obligated to make quarterly distributions of available cash to its unitholders. We receive our share of these cash distributions through our limited partner ownership interest, general partner interest, and incentive distribution rights (IDRs) we are entitled to as the general partner. Prior to February 15, 2011, we held subordinated units in EPB. Upon payment of the quarterly cash distribution for the fourth quarter of 2010, the financial tests required for the conversion of subordinated units into common units were satisfied. As a result, our subordinated units were converted on February 15, 2011 into common units on a one-for-one basis effective January 3, 2011.

To the extent that the consideration for the sales of assets to EPB is not in the form of additional equity in EPB, our interest in our assets becomes diluted over time. However our economic interest will benefit from the receipt of incentive distributions in accordance with the partnership agreement.

Our IDRs provide for the receipt of an increasing portion of quarterly distributions based on the level of distribution to all unitholders. We can elect to relinquish the right to receive incentive distribution payments and reset, at higher levels, the minimum quarterly distribution amount and cash target distribution levels upon which the incentive distribution payments would be set. We are currently entitled to receive the maximum level of incentive distributions.

Net Income Attributable to Noncontrolling Interests. The components of net income attributable to noncontrolling interests on our statements of income are as follows for the quarters and nine months ended September 30:

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
		(In millions)		
EPB	$ 55	$ 25	$ 161	$ 75
Preferred Stock of Cheyenne Plains (Note 15)	5	5	15	15
Preferred Stock of Ruby (Note 15)	15	11	50	11
Net income attributable to noncontrolling interests	$ 75	$ 41	$ 226	$ 101

Table of Contents

13. Business Segment Information

As of September 30, 2011, our business consists of the following segments: Pipelines, Exploration and Production, and Marketing. We also have other business and corporate activities. 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. A further discussion of each segment follows.

Pipelines. Our Pipelines segment provides natural gas transmission, storage, and related services. As of September 30, 2011, we conducted our activities primarily through eight wholly or partially owned interstate pipeline systems and equity interests in three 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.

Exploration and Production. Our Exploration and Production segment is engaged in the exploration for and the acquisition, development and production of oil, natural gas and NGL, in the U.S., Brazil and Egypt.

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

Other. Our other activities include our corporate general and administrative functions, midstream operations and miscellaneous businesses.

Beginning January 1, 2011, we use segment earnings before interest expense and income taxes (Segment EBIT) as a measure to assess the operating results and effectiveness of our business segments. We believe Segment EBIT is useful to our investors because it allows them to use the same performance measure analyzed internally by our management to evaluate the performance of our businesses and investments without regard to the manner in which they are financed or our capital structure. Segment EBIT is defined as net income (loss) adjusted for interest and debt expense and income taxes. It does not reflect a reduction for any amounts attributable to noncontrolling interests. Segment EBIT may not be comparable to measurements used by other companies. Additionally, Segment 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. Our 2010 amounts have been conformed to reflect our current performance measure.

Below is a reconciliation of our Segment EBIT to our net income for the periods ended September 30:

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(In millions)			
Segment EBIT	$ (181)	$ 513	$ 830	$ 1,913
Interest and debt expense	(242)	(255)	(721)	(782)
Income tax benefit (expense)	130	(75)	73	(343)
Net income (loss)	(293)	183	182	788
Net income attributable to noncontrolling interests	(75)	(41)	(226)	(101)
Net income (loss) attributable to El Paso Corporation	$ (368)	$ 142	$ (44)	$ 687

The following tables reflect our segment results for the quarters and nine months ended September 30:

	Segments					
	Pipelines	Exploration and Production	Marketing	Other	Eliminations	Total
			(In millions)			
Quarter Ended September 30, 2011						
Revenue from external customers	$ 743	$ 481(1)	$ 177	$ 2	$	$ 1,403
Intersegment revenue	17	172(1)	(186)		(3)	
Operation and maintenance	213	114		39		366
Loss on deconsolidation of subsidiary	600(2)					600
Ceiling test charges		152				152
Depreciation, depletion and amortization	136	157		6		299
Earnings (losses) from unconsolidated affiliates	24	(3)		15		36
Segment EBIT	(209)	183	(10)	(145)(3)		(181)
Quarter Ended September 30, 2010						
Revenue from external customers	$ 680	$ 340(1)	$ 174	$ 19	$	$ 1,213
Intersegment revenue	12	179(1)	(190)	7	(8)	
Operation and maintenance	220	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
Segment EBIT	375	261	(12)	(111)(3)		513

(1) Revenues from external customers include gains of $251 million and $184 million for the quarters ended September 30, 2011 and 2010 related to our financial derivative contracts associated with our oil and natural gas production. Intersegment revenues represent sales to our Marketing segment.

(2) Reflects a non-cash loss of approximately $475 million based on the difference between the net carrying value of Ruby and the estimated fair value of our investment in Ruby and a non-cash loss of approximately $125 million related to the recognition of the accumulated other comprehensive loss associated with interest rate swaps on the Ruby debt (see Note 15).

(3) Includes loss on debt extinguishment of approximately $101 million and $104 million for the quarters ended September 30, 2011 and 2010 primarily related to debt repurchases.

Table of Contents

	Segments Pipelines	Exploration and Production	Marketing (In millions)	Other	Eliminations	Total
Nine Months Ended September 30, 2011						
Revenue from external customers	$ 2,130	$ 944(1)	$ 550	$ 4	$	$ 3,628
Intersegment revenue	105	494(1)	(591)	2	(10)	
Operation and maintenance	614	312	4	65	(1)	994
Loss on deconsolidation of subsidiary	600(2)					600
Ceiling test charges		152				152
Depreciation, depletion and amortization	360	437		18		815
Earnings (losses) from unconsolidated affiliates	74	(4)		28		98
Segment EBIT	718	402	(45)	(245)(3)		830
Nine Months Ended September 30, 2010						
Revenue from external customers	$ 2,072	$ 966(1)	$ 556	$ 38	$	$ 3,632
Intersegment revenue	37	569(1)	(601)	11	(16)	
Operation and maintenance	599	275		37		911
Ceiling test charges		16				16
Depreciation, depletion and amortization	327	352		20		699
Earnings (losses) from unconsolidated affiliates	157(4)	(3)		13		167
Segment EBIT	1,299	754	(44)	(96)(3)		1,913

(1) Revenues from external customers include gains of $274 million and $468 million for the nine months ended September 30, 2011 and 2010 related to our financial derivative contracts associated with our oil and natural gas production. Intersegment revenues represent sales to our Marketing segment.

(2) Reflects a non-cash loss of approximately $475 million based on the difference between the net carrying value of Ruby and the estimated fair value of our investment in Ruby and a non-cash loss of approximately $125 million related to the recognition of the accumulated other comprehensive loss associated with interest rate swaps on the Ruby debt (see Note 15).

(3) Includes loss on debt extinguishment of approximately $169 million and $104 million for the nine months ended September 30, 2011 and 2010 primarily related to debt repurchases.

(4) Includes a gain of approximately $80 million for the nine months ended September 30, 2010 related to the sale of certain of our interests in Mexican pipeline and compression assets.

Total assets by segment are presented below:

	September 30, 2011	December 31, 2010
	(In millions)	
Pipelines(1)	$ 18,396	$ 19,651
Exploration and Production	4,724	4,657
Marketing	182	222
Other	960	943
Total segment assets	24,262	25,473
Eliminations	(184)	(203)
Total consolidated assets	$ 24,078	$ 25,270

(1) Reflects the deconsolidation of Ruby in the third quarter of 2011.

14. Accounts Receivable Sales Programs

Accounts Receivable Sales Programs. We participate in accounts receivable sales programs where several of our pipeline subsidiaries sell receivables in their entirety to a third-party financial institution (through wholly-owned special purpose entities). The sale of these accounts receivable (which are short-term assets that generally settle within 60 days) qualify for sale accounting. The third party financial institution involved in 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 control, direct, or exert significant influence over its overall activities since our receivables do not comprise a significant portion of its operations.

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 (which we refer to as a deferred purchase price). Our ability to recover the deferred purchase price is based solely on the collection of the underlying receivables. The table below contains information related to our accounts receivable sales programs.

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(In millions)			
Accounts receivable sold to the third-party financial institution[1]	$ 647	$ 599	$ 1,851	$ 1,805
Cash received for accounts receivable sold under the programs	356	338	1,051	1,124
Deferred purchase price related to accounts receivable sold	291	261	800	681
Cash received related to the deferred purchase price	295	266	793	746
Amount paid in conjunction with terminated programs [2]				90

(1) During the quarters and nine months ended September 30, 2011 and 2010, losses recognized on the sale of accounts receivable were immaterial.

(2) In January 2010, we terminated our previous accounts receivable sales programs and paid $90 million to acquire the related senior interests in certain receivables under those programs. See our 2010 Annual Report on Form 10-K for further information.

	September 30, 2011	December 31, 2010
	(In millions)	
Accounts receivable sold and held by third-party financial institution	$ 213	$ 210
Uncollected deferred purchase price related to accounts receivable sold [1]	96	89

(1) Initially recorded at an amount which approximates its fair value as a Level 2 measurement.

The deferred purchase price related to the accounts receivable sold is reflected as other accounts receivable on our balance sheet. Because the cash received up front and the deferred purchase price 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 accounts receivable sales programs as operating cash flows on our statement of cash flows. Under the accounts receivable sales programs, we service 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 quarters and nine months ended September 30, 2011 and 2010.

Table of Contents

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

Our net investments in and earnings (losses) from our unconsolidated affiliates are as follows as of September 30, 2011 and December 31, 2010 and for the quarters and nine months ended September 30:

	Investment		Earnings (Losses) from Unconsolidated Affiliates			
			Quarters Ended		Nine Months Ended	
	September 30, 2011	December 31, 2010	September 30, 2011	September 30, 2010	September 30, 2011	September 30, 2010
	(In millions)		(In millions)			
Net Investment and Earnings (Losses)						
Ruby	$ 1,069	$	$ (1)	$	$ (1)	$
Citrus[1]	897	822	25	27	74	67
Four Star [2]	351	393	(3)	(2)	(4)	(3)
Gulf LNG[3]	237	266	(1)	(1)	(1)	(1)
Bolivia-to-Brazil Pipeline	108	104	10	1	13	10
Other[4]	94	88	6	3	17	94
Total	$ 2,756	$ 1,673	$ 36	$ 28	$ 98	$ 167

(1) As of September 30, 2011, we had outstanding receivables of approximately $37 million, included in other long term assets, related to a promissory note from Citrus whereby we will lend up to $150 million.

(2) We recorded amortization of our purchase cost in excess of the underlying net assets of Four Star Oil and Gas Company (Four Star) of $8 million and $9 million for the quarters ended September 30, 2011 and 2010 and $26 million and $28 million for the nine months ended September 30, 2011 and 2010.

(3) As of September 30, 2011 and December 31, 2010, we had outstanding advances and receivables of $150 million and $85 million, included in other long term assets, related to our investment in Gulf LNG. On October 1, 2011, the Gulf LNG Clean Energy project was placed in service.

(4) Includes our investment in Gasoductos de Chihuahua for the nine months ended September 30, 2010. 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.

Ruby. As of September 30, 2011, we have an equity investment in the Ruby pipeline project totaling approximately $1,069 million. Prior to September 2011, we reflected Ruby Pipeline Holding Company, L.L.C. (Ruby) as a consolidated variable interest entity because we were its primary beneficiary. In mid-September 2011, we met certain conditions of our lenders and our partner, Global Infrastructure Partners (GIP), and El Paso s guarantee of GIP s preferred interests in Ruby and Cheyenne Plains Investment Company, L.L.C. (Cheyenne Plains) expired. Accordingly, we no longer reflect approximately $769 million of preferred interests in subsidiaries between liabilities and equity on our balance sheet, which included $700 million of GIP s investment in preferred stock of subsidiaries and $69 million in accrued preferred returns. As a result of us meeting these conditions, GIP transferred its $145 million convertible preferred stock in Cheyenne Plains to us in exchange for additional preferred stock in Ruby. Following these events, Ruby and Cheyenne Plains are no longer considered variable interest entities. Although we continue to operate the Ruby pipeline, we do not have a controlling financial interest in Ruby; therefore, we deconsolidated it prospectively in our financial statements.

Prior to deconsolidation, Ruby s individual assets and liabilities were reflected on our balance sheet, Ruby s consolidated financial results were reflected in our income statement, and GIP s returns on its preferred interests in Ruby and Cheyenne Plains were recorded in net income attributable to noncontrolling interests on our income statement. Upon Ruby s deconsolidation in mid-September 2011, we no longer reflected the individual assets and liabilities of Ruby on our balance sheet and began recording Ruby s earnings in earnings (losses) from unconsolidated affiliates on our income statement. At the time of deconsolidation, amounts on our balance sheet consisted primarily of approximately $3,673 million in property, plant and equipment, $348 million in regulatory and other assets, $125 million in price risk management liabilities associated with interest rate swaps on Ruby s debt, $138 million in other liabilities, and $1,447 million in long term debt. For a further discussion of Ruby, see Notes 9 and 12 and our 2010 Annual Report on Form 10-K.

Upon deconsolidation, we were required to assess our investment in Ruby for impairment based on fair value, which is a different model than assessing recoverability of the Ruby pipeline based on estimated undiscounted cash flows while it was consolidated. Our fair value assessment was based on a number of factors, including the present value of anticipated distributable cash flows to be produced from the underlying operations of the Ruby investment. Determining these cash flows required the use of assumptions related to the future demand for Ruby s capacity, forecasted commodity prices and interest rates, anticipated economic conditions, the timing of GIP s conversion of their preferred interest into a common equity interest, and other inputs, many of which are not available as observable market data. As a result, our estimate of fair value was a Level 3 fair value measurement. As a result of the deconsolidation of Ruby and our fair value assessments, we recorded a third quarter non-cash loss of approximately $475 million based on the difference between the net carrying value in Ruby and the estimated fair value of our investment in Ruby. We also recorded a non-cash loss of $125 million related to the recognition of the accumulated other comprehensive loss associated with interest rate swaps on Ruby s debt. Subsequent to deconsolidation, Ruby s interest rate swaps continue to hedge Ruby s project level debt.

Summarized Financial Information of Unconsolidated Affiliates. Below is summarized financial information of our proportionate share of the operating results of our unconsolidated affiliates before preferred interests for the quarters and nine months ended September 30, 2011 and 2010.

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(In millions)			
Summarized Financial Information				
Operating results data:				
Operating revenues	$ 181	$ 126	$ 478	$ 386
Operating expenses	95	63	264	201
Net income	46	40	120	119

We received distributions and dividends from our unconsolidated affiliates of $17 million for each of the quarters ended September 30, 2011 and 2010 and $48 million and $53 million for the nine months ended September 30, 2011 and 2010. Our transactions with unconsolidated affiliates were not material to our operating results during the quarters and nine months ended September 30, 2011 and 2010.

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 $62 million of Brazilian reais-denominated accounts receivable) by the plants power purchaser, which are also guaranteed by the purchaser s parent, Eletrobras, Brazil s state-owned utility. The power utility that purchased the power from these facilities and its parent have asserted counterclaims that would largely offset our accounts receivable. Absent resolution of these matters through settlement, we anticipate that the ultimate resolution will likely occur through legal proceedings in the Brazilian courts. We believe the receivables are collectible and therefore have not established an allowance against the receivables owed. We have reviewed our obligations under the power purchase agreements and have accrued what we believe is an appropriate amount in relation to the asserted counterclaims. We believe the remaining counterclaims are without merit. Based on the anticipated timing of the resolution of the legal proceedings, we have classified our accounts receivable and the accrual for the counterclaims as a non-current asset and liability in our financial statements.

Our project companies that previously owned 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 has been indemnifying our project companies for these ICMS taxes, along with related interest and penalties. In the third quarter of 2010, a court hearing the Rio Negro case seized funds from certain of El Paso s Rio Negro bank accounts in partial satisfaction of and as security for this potential tax liability. In order to prevent collection efforts by the tax authorities for this matter against our project companies, security must be provided for the potential tax liability to the court s satisfaction. The power purchaser and the taxing authorities have agreed upon the posting of shares in a subsidiary of the power purchaser s parent as security. The court hearing the Rio Negro case has now accepted these shares as security and we have been advised that the court hearing the Manaus case has now ruled in a similar fashion. The power purchaser asked the court hearing the Rio Negro case to vacate its order encumbering the assets belonging to our Rio Negro project company and its shareholders. That court has now lifted its order in respect of the project company s assets. Until this tax matter is fully resolved, 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. Based on our assessment, we have not established any accruals for this matter.

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 should be read in conjunction with, information disclosed in our 2010 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 2011, our Segment EBIT was $830 million, compared with $1,913 million for the same period in 2010. Although we continued to benefit from expansion projects placed in service in 2010 and 2011, Pipeline Segment EBIT in 2011 was significantly impacted by a third quarter non-cash loss of approximately $475 million based on the difference between the net carrying value of Ruby and the estimated fair value of our investment in Ruby. We also recorded a non-cash loss of approximately $125 million upon deconsolidation associated with the recognition of the accumulated other comprehensive loss associated with interest rate swaps on the Ruby debt. Our Exploration and Production segment increased production volumes year over year; however, Segment EBIT year-to-date decreased by approximately $352 million largely due to the mark-to-market impacts of our financial derivatives and a third quarter non-cash Brazilian ceiling test charge of approximately $152 million. Our results during these periods were also significantly impacted by $169 million in debt extinguishment losses associated with the repurchase of approximately $1.0 billion of our debt in 2011 and a gain of approximately $80 million in the second quarter of 2010 related to the sale of our Mexican pipeline and compression assets. Our quarterly results are discussed further in the individual segment results that follow.

We have now completed what was an $8 billion backlog of expansion projects, the largest in our company s history. During 2011, the Florida Gas Transmission (FGT) Phase VIII Expansion, Phases I and II of the SNG South System III Expansion, Phase II of the SNG Southeast Supply Header, the Gulf LNG Clean Energy and the TGP 300 Line projects were placed in service on time and on budget. In July 2011, we placed our Ruby pipeline project in service four months later than planned due to permitting and weather delays and approximately $0.7 billion over the original $3.0 billion budget. In our exploration and production business, our continued 2011 capital focus is in our Haynesville, Altamont, Eagle Ford, and Wolfcamp areas. Finally, in our midstream business, we continue to seek out opportunities that focus on synergies with our pipeline and/or exploration and production businesses. For the remainder of 2011, we expect that our pipeline and exploration and production operations will provide a strong base of earnings and operating cash flow.

From a liquidity perspective, as of September 30, 2011 we had approximately $1.5 billion of available liquidity (exclusive of cash and credit facility capacity of EPB). During the first nine months of 2011 we received approximately $1.4 billion in cash in conjunction with contributing additional ownership interests in SNG and CIG to our MLP, which funded the acquisitions primarily through the issuance of common units and debt. Additionally during the first nine months of 2011, among other debt repurchase and financing activities, we refinanced approximately $2.25 billion of our revolving credit facilities (excluding the $1.0 billion EPPOC revolving credit facility also refinanced in May 2011). In July 2011, our $500 million unsecured credit facility matured. As further described in *Liquidity and Capital Resources,* we believe we are well positioned for the remainder of 2011 to meet our obligations.

On October 16, 2011, we announced a definitive agreement whereby KMI will acquire El Paso in a transaction that values El Paso at approximately $38 billion which includes the assumption of debt. KMI has announced that they intend to sell our exploration and production assets and as such, we will no longer pursue the tax-free spin-off of our exploration and production business into a new publicly traded company.

Upon the merger, El Paso shareholders will receive a combination of Class P shares of common stock of KMI, common stock purchase warrants of KMI and cash. Each share of El Paso common stock (excluding any shares held by KMI and its subsidiaries or by El Paso and dissenting shares in accordance with Delaware law), will, at the effective time of the merger, be converted into the right to receive, at the election of the holder but subject to pro-ration with respect to the stock and cash portion such that approximately 57% of the aggregate merger consideration (excluding the warrants) is paid in cash and approximately 43% (excluding the warrants) is paid in Class P common stock of KMI, par value $0.01 per share (the KMI Class P Common Stock): (i) 0.9635 of a share of KMI Class P Common Stock and 0.640 of a common stock purchase warrant of KMI (a KMI Warrant), (ii) $25.91 in cash without interest and 0.640 of a KMI Warrant or (iii) 0.4187 of a share of KMI Class P Common Stock, $14.65 in cash without interest and 0.640 of a KMI Warrant. Each KMI Warrant will entitle its holder to purchase one share of KMI Class P Common Stock at an exercise price of $40.00 per share, subject to certain adjustments, at any time during the five-year period following the closing of the merger.

Table of Contents

The transactions have been approved by each of our and KMI s board of directors. The completion of the transactions is subject to satisfaction or waiver of certain closing conditions including, among others, customary regulatory approvals, approval of the transactions by our stockholders and approval of the issuance of KMI stock and warrants by KMI s stockholders. A voting agreement has been executed by certain stockholders of KMI, holding approximately 75% of the voting power of KMI, in which such stockholders have agreed to vote in favor of the merger and the issuance of KMI stock and warrants. The completion of the merger will constitute a change of control for El Paso Corporation that may trigger change in control provisions in certain agreements (e.g. debt) to which we are a party.

Additional information regarding the proposed transactions and the terms and conditions of the merger agreement, voting agreement and other related agreements is set forth in our Current Report on Form 8-K, filed on October 17, 2011.

Table of Contents

Segment Results

As of September 30, 2011, our business consists of the following segments: Pipelines, Exploration and Production, and Marketing. We also have other business and corporate activities that include midstream and other miscellaneous businesses. Our segments are managed separately, provide a variety of energy products and services, and require different technology and marketing strategies.

Beginning January 1, 2011, we use segment earnings before interest expense and income taxes (Segment EBIT) as a measure to assess the operating results and effectiveness of our business segments. We believe Segment EBIT is useful to our investors because it allows them to use the same performance measure analyzed internally by our management to evaluate the performance of our businesses and investments without regard to the manner in which they are financed or our capital structure. Segment EBIT is defined as net income (loss) adjusted for interest and debt expense and income taxes. It does not reflect a reduction for any amounts attributable to noncontrolling interests. Segment EBIT may not be comparable to measurements used by other companies. Additionally, Segment 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. Our 2010 amounts have been conformed to reflect our current performance measure.

Below is a reconciliation of our Segment EBIT to our consolidated net income (loss) for the quarters and nine months ended September 30:

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(In millions)			
Segment				
Pipelines	$ (209)	$ 375	$ 718	$ 1,299
Exploration and Production	183	261	402	754
Marketing	(10)	(12)	(45)	(44)
Other	(145)	(111)	(245)	(96)
Segment EBIT	(181)	513	830	1,913
Interest and debt expense	(242)	(255)	(721)	(782)
Income tax benefit (expense)	130	(75)	73	(343)
Net income (loss)	(293)	183	182	788
Net income attributable to noncontrolling interests	(75)	(41)	(226)	(101)
Net income (loss) attributable to El Paso Corporation	$ (368)	$ 142	$ (44)	$ 687

Table of Contents

Pipelines Segment

Overview and Operating Results. Our Pipelines Segment EBIT for the nine months ended September 30, 2011 benefited primarily from expansion projects placed in service in 2010 and 2011, an increase in AFUDC on pipeline expansion projects prior to them being placed in service and higher rates on our TGP system effective June 1, 2011 due to its November 2010 rate case. More than offsetting these items were non-cash losses associated with the deconsolidation of Ruby in the third quarter of 2011 and a gain on the sale of our Mexican pipeline and compression assets in 2010. Listed below is a further discussion of these items, the operating results for our Pipelines segment as well as a discussion of other factors impacting Segment EBIT for the quarters and nine months ended September 30, 2011 compared with the same periods in 2010, or that could potentially impact Segment EBIT in future periods.

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(In millions, except for volumes)			
Operating revenues	$ 760	$ 692	$ 2,235	$ 2,109
Operating expenses[1]	(1,014)	(402)	(1,789)	(1,128)
Operating income (loss)	(254)	290	446	981
Other income, net	45	85	272	318
Segment EBIT	$ (209)	$ 375	$ 718	$ 1,299
Throughput volumes (BBtu/d)[2][3]	18,511	17,235	18,086	17,971

(1) Includes losses associated with the deconsolidation of Ruby for the quarter and nine months ended September 30, 2011.

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

(3) Throughput volumes for the nine months ended September 30, 2010 include 744 BBtu/d related to our Mexican pipeline assets which were sold in 2010.

	Quarter Ended September 30, 2011 Variance				Nine Months Ended September 30, 2011 Variance			
	Operating Revenue	Operating Expense	Other	Total	Operating Revenue	Operating Expense	Other	Total
	Favorable/(Unfavorable) (In millions)							
Expansions	$ 53	$ (23)	$ (36)	$ (6)	$ 115	$ (37)	$ 34	$ 112
Reservation/ usage revenues and expenses	56	(4)		52	41	(11)		30
Gas not used in operations and revaluations	(38)	4		(34)	(38)	3		(35)
Operating and general and		(4)		(4)		(38)		(38)

administrative expense								
Loss on deconsolidation of Ruby		(600)		(600)		(600)		(600)
Asset sale/write downs		21		21		31	(80)	(49)
Other[1]	(3)	(6)	(4)	(13)	8	(9)		(1)
Total impact on Segment EBIT	$ 68	$ (612)	$ (40)	$ (584)	$ 126	$ (661)	$ (46)	$ (581)

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

Expansions. During 2011, we benefited from increased reservation revenues due to placing a number of expansion projects in service in 2010 and 2011, including (i) the WIC System Expansion; (ii) Phase A of both the SLNG Elba Expansion III and Elba Express Pipeline Expansion projects; (iii) CIG Raton 2010 Expansion; (iv) Phases I and II of the SNG South System III Expansion; (v) the FGT Phase VIII Expansion and (vi) the Ruby pipeline project. In October 2011, the Gulf LNG Clean Energy project was placed in service and in November 2011, the TGP 300 Line expansion project was also placed in service.

We capitalize a carrying cost (AFUDC) on funds related to our construction of long-lived assets. During the quarter ended September 30, 2011, our other income declined by approximately $36 million as compared to the same period in 2010 primarily due to Ruby ceasing to record AFUDC in June 2011 based on an amendment of the Ruby FERC certificate which limited AFUDC accruals. Our Pipelines Segment EBIT for the nine months ended September 30, 2011 benefited from an increase in other income of approximately $34 million as compared to the same period in 2010 associated with the equity portion of AFUDC, primarily on our Ruby pipeline and TGP 300 Line projects, offset by AFUDC recorded on projects placed in service during 2010.

Reservation/Usage Revenues and Expenses. Our reservation and usage revenues on each of our systems for the quarter and nine months ended September 30, 2011 were impacted by a number of factors, including regulatory actions, competition, weather and changes in supply and demand, the more significant of which are noted below:

TGP. Revenues increased by $50 million and $69 million for the quarter and nine months ended September 30, 2011 compared to the same periods in 2010 primarily due to higher rates which became effective June 1, 2011 as a result of its November 2010 rate case that is further discussed below. This increase was partially offset by lower revenues from gas not used in operations.

EPNG. Reservation and usage revenues increased by approximately $10 million for the quarter ended September 30, 2011 and decreased by $12 million for the nine months ended September 30, 2011 compared to the same periods in 2010. Effective April 1, 2011, EPNG experienced higher rates as a result of its September 2010 rate case. However, EPNG also experienced reduced demand due to high gas storage levels and increased hydroelectric generation in EPNG s California market, the nonrenewal of certain expiring contracts, the sale of open capacity at lower prices due to lower basis differentials and lower revenues related to certain interruptible services.

SNG. Nonrenewal of expiring contracts decreased Segment EBIT by $3 million and $7 million during the quarter and nine months ended September 30, 2011 compared to the same periods in 2010. Additionally, SNG s usage revenues were lower by $1 million and $5 million primarily due to unfavorable market conditions during 2011 as compared to 2010.

WIC/CIG. Higher transportation expenses on our WIC and CIG systems of $4 million and $10 million for the quarter and nine months ended September 30, 2011 negatively impacted 2011 results when compared to the same periods in 2010 due to increased third party capacity commitments.

Gas Not Used in Operations and Revaluations. Prior to June 1, 2011, gas not used in operations on our TGP system resulted in revenues to us, which we recognized when the volumes were retained, valued at the market price specified in our tariff. During 2011, we experienced lower retained fuel volumes in excess of fuel used in operations which unfavorably impacted our Segment EBIT by $40 million during the nine months ended September 30, 2011 compared to the same period in 2010. Partially offsetting the effect of this unfavorable item was $4 million of lower electric compression expenses from decreased utilization and $4 million of natural gas processing revenues recognized during the nine months ended September 30, 2011. Effective June 1, 2011, TGP implemented a fuel volume tracker as part of its rate case filed with the FERC and as a result, no longer recognizes revenue associated with gas not used in operations which lowered Segment EBIT by $41 million during the quarter ended September 30, 2011 compared to the same period in 2010. The unfavorable impacts associated with these operational activities are offset by higher reservation revenues discussed above.

Operating and General and Administrative Expenses. During the quarter and nine months ended September 30, 2011, our operating and general and administrative expenses were higher compared to the same periods in 2010 primarily due to higher benefits, payroll, and contractor costs of $17 million and $39 million. Additionally, our Segment EBIT was unfavorably impacted by $6 million due to higher property tax assessments on several of our pipeline systems during the nine months ended September 30, 2011. Partially offsetting these unfavorable impacts were lower corporate overhead allocations and a favorable franchise tax settlement on our TGP system which combined reduced operating expenses by $10 million and $12 million for the quarter and nine months ended September 30, 2011.

Loss on Deconsolidation of Ruby. In September 2011, upon meeting certain conditions of our partner and the lenders, we deconsolidated Ruby and began reflecting it as an investment in an unconsolidated affiliate. Subsequent to deconsolidation, Ruby s income (loss) is reflected in earnings from unconsolidated affiliates on our income statement and is included in Pipeline Segment EBIT. Earnings from unconsolidated affiliates is after interest, taxes and the preferred return of our partner. As a result of the deconsolidation of Ruby, we recorded a third quarter non-cash loss of approximately $475 million based on the difference between the net carrying value of Ruby and the estimated fair value of our investment in Ruby. We also recorded a non-cash loss of approximately $125 million related to the recognition of the accumulated other comprehensive loss associated with interest rate swaps on the Ruby debt. Subsequent to deconsolidation, Ruby s interest rate swaps continue to hedge Ruby s project level debt. For additional information on our Ruby pipeline project, see Item 1, Financial Statements, Note 15.

Asset Sale/Write Downs. During 2010, our Pipelines Segment EBIT was impacted by the following asset write-downs and sale: (i) a $21 million non-cash asset write-down in the third quarter based on a FERC order related to the sale of the Natural Buttes compressor station and gas processing plant in 2009; (ii) an impairment of approximately $10 million in the first quarter primarily related to a decision not to continue with a storage project due to market conditions; and (iii) a third quarter gain of approximately $80 million on the sale of our interests in certain Mexican pipeline and compression assets.

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, several of our pipelines have projected upcoming rate actions further described below.

EPNG Rate Case. In September 2010, EPNG filed a new rate case proposing an increase in its base tariff rates which 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. A hearing commenced in late October 2011. It is uncertain whether the requested increase will be achieved in the context of any settlement between EPNG and its customers or following the outcome of a hearing in the rate case. Although the final outcome is not currently determinable, we believe our accruals established for this matter are adequate.

TGP Rate Case. In November 2010, TGP filed a rate case with the FERC proposing an increase in its base tariff rates and the implementation of a fuel volume tracker with a reduction in TGP s fuel retention rates, among other things. In December 2010, the FERC issued an order accepting and suspending the effective date of the proposed rates to June 1, 2011, subject to refund, the outcome of a hearing and other proceedings. In September 2011, TGP filed a proposed settlement with the FERC, which was uncontested by its customers. The proposed settlement provides for, among other things, an increase in TGP s revenues of approximately $60 million to $70 million annually, net of revenues from excess fuel retention, significant contract extensions until October 2014 and a requirement to file new rates to be effective no earlier than April 2014 but no later than November 2015. Although the FERC has not yet approved the proposed settlement, we believe our accruals established for this matter are adequate.

CIG Rate Case. In August 2011, the FERC approved an uncontested pre-filing settlement of a rate case required under the terms of CIG s previous settlement. The settlement generally provides for CIG s current tariff rates to continue until its next general rate case which will be effective after October 1, 2014 but no later than October 1, 2016.

Exploration and Production Segment

Overview and Strategy

Our Exploration and Production segment conducts our oil and natural gas exploration and production activities. The success of this segment is driven by the ability to locate and develop economic oil and natural gas reserves and extract those reserves at the lowest possible production and administrative costs. Accordingly, we manage this business with the goal of creating value through disciplined capital allocation, cost control and portfolio management. Our strategy focuses on building and applying competencies in assets with repeatable programs, executing to improve capital and expense efficiency, and maximizing returns by adding assets and inventory that match our competencies and divesting assets that do not. During 2011, we sold non-core oil and natural gas properties located in our Central, Western and Southern divisions in several transactions from which we received proceeds that totaled approximately $570 million. For a further discussion of our business strategy in our exploration and production business, see our 2010 Annual Report on Form 10-K.

Our profitability and performance is impacted by, among other factors, 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. We may also 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). To the extent possible, we attempt to mitigate certain of these risks through actions, such as entering into 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, 2011 and 2010

Volumes. Our volumes by commodity for the nine months ended September 30 were as follows:

	2011	2010
Natural Gas (MMcf/d)		
Consolidated volumes	656	615
Unconsolidated affiliate volumes	46	47
Total Combined	702	662
Oil and condensate (MBbls/d)		
Consolidated volumes	15	13
Unconsolidated affiliate volumes	1	1
Total Combined	16	14
NGL (MBbls/d)		
Consolidated volumes	3	4
Unconsolidated affiliate volumes	2	2
Total Combined	5	6
Equivalent Volumes (MMcfe/d)		
Consolidated volumes	762	715
Unconsolidated affiliate volumes	61	62
Total Combined	823	777

Our average daily production volumes for the nine months ended September 30, 2011 were 823 MMcfe/d, including 61 MMcfe/d from our equity interest in the production of Four Star. Below is an analysis of our production by division for the periods ended September 30:

	2011	2010
	MMcfe/d	
United States		
Central	414	328
Western	155	159
Southern[1]	160	196
International		
Brazil	33	32
Total Consolidated	762	715
Unconsolidated affiliate	61	62
Total Combined	823	777

(1) In 2011, our Gulf Coast division was renamed the Southern division, and we made minor changes to the properties contained within our various domestic operating divisions. Divisional amounts for prior periods have been adjusted to reflect these changes.

Central division Our 2011 Central division production volumes continued to increase as a result of our successful drilling programs in the Haynesville shale. As of September 30, 2011, we had 91 operated wells and our total production was approximately 257 MMcfe/d related to our Haynesville program. In addition, in south Louisiana we are developing our emerging Wilcox program. This is a relatively new oil play we have added to our drilling program. As of September 30, 2011, we had eight operated wells related to our Wilcox program.

Western division Our 2011 Western division production volumes are roughly flat compared to 2010 due to natural declines in the Rockies and County Line programs offset by increased production volumes in our Altamont and Raton programs. As of September 30, 2011 we had 254 operated wells and our total oil production was approximately 7 MBbls/d related to our Altamont program.

Southern division Our 2011 Southern division production volumes decreased primarily due to natural declines and lower levels of drilling activity in the Texas Gulf Coast and Gulf of Mexico areas. In this division, we continue to focus on our Eagle Ford shale activity, where in 2011 we have successfully drilled 37 additional wells, for a total of 57 wells. These wells are located principally in the liquids rich area of the Eagle Ford shale. As of September 30, 2011, our total oil and NGL production at Eagle Ford was approximately 7 MBbls/d, and additional production was constrained due to limited natural gas takeaway capacity. Subsequent to September 30, 2011, upon the completion of a natural gas gathering system, our oil and NGL production has increased to approximately 10 MBbls/d. We also continue to assess our Wolfcamp shale area, having drilled 12 wells during 2011.

International Our 2011 production volumes in Brazil increased due to production from our Camarupim Field. A fourth well in the field began production during the third quarter of 2011. During the quarter ended September 30, 2011, we were informed that our environmental permit request for the Pinauna Field in the Camamu Basin was denied. As a result, we released $94 million of unevaluated capitalized costs related to this field into the Brazilian full cost pool. We have filed an appeal and are awaiting a response. Additionally, during the quarter and nine months ended September 30, 2011, we released approximately $42 million and $86 million, respectively, of unevaluated capitalized costs related to the ES-5 block upon the completion of our evaluation of exploratory wells drilled in 2009 and 2010 without any additions to our proved reserves. We will continue to pursue alternatives for the hydrocarbons discovered in these areas. In Egypt, during the remainder of the year we expect to continue to evaluate the commerciality of areas within our South Alamein and South Mariut blocks.

As a result of the developments in Brazil, we recorded a non-cash ceiling test charge of approximately $152 million in our Brazilian full cost pool for the quarter and nine months ended September 30, 2011. We may incur additional ceiling test charges in Brazil in the future depending on the value of our proved reserves, which are subject to change as a result of factors such as prices, costs and well performance. Additionally, we may incur ceiling test charges in Egypt depending on the results of our drilling activities in that country. At September 30, 2011, we have total oil and natural gas capitalized costs of approximately $207 million and $71 million in Brazil and Egypt, of which $8 million and $71 million are unevaluated capitalized costs.

Table of Contents

Cash Operating Costs. We monitor cash operating costs required to produce our oil and natural gas 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 our Exploration and Production segment, however, this measure may not be comparable to those used by other companies. During the nine months ended September 30, 2011, cash operating costs per unit increased to $1.80/Mcfe as compared to $1.76/Mcfe during the same period in 2010 due to increased lease operating expenses.

Capital Expenditures. Our total oil and natural gas capital expenditures were $1,183 million for the nine months ended September 30, 2011, of which $1,158 million were domestic capital expenditures.

Capital expenditures for the nine months ended September 30, 2011 and rig count by core program as of September 30, 2011 were:

	Capital Expenditures (In millions)	Rig Count
Haynesville	$ 319	4
Altamont	120	2
Eagle Ford	443	3
Wolfcamp	115	2
Other, including International	186	2
Total capital expenditures	$ 1,183	13

Outlook for 2011

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

- Capital expenditures, excluding acquisitions, of approximately $1.6 billion, approximately 60 percent of which is expected to be allocated to oil and liquids programs.

- Average daily total production volumes for the year of approximately 830 MMcfe/d to 840 MMcfe/d, which includes approximately 60 MMcfe/d from Four Star.

- Average daily oil production volumes for the year of approximately 16.5 MBbls/d to 18.5 MBbls/d, including Four Star.

- Average cash operating costs between $1.70/Mcfe and $1.85/Mcfe for the year; and

- Depreciation, depletion and amortization rate between $2.10/Mcfe and $2.15/Mcfe.

Price Risk Management Activities

We enter into derivative contracts on our oil and natural gas production to stabilize cash flows and reduce the risk and financial impact of downward commodity price movements on commodity sales. Because we apply mark-to-market accounting on our financial derivative contracts and because we do not hedge all of our price risks, this strategy only partially reduces our commodity price exposure. Our reported results of operations, financial position and cash flows can be impacted significantly by commodity price movements from period to period. Adjustments to our strategy and the decision to enter into new positions or to alter existing positions are made based on the goals of the overall company. During the first nine months of 2011, approximately 82 percent of our natural gas production and 100 percent of our crude oil production were economically hedged at average floor prices of $5.76 per MMBtu and $85.99 per barrel, respectively.

Table of Contents

The following table reflects the contracted volumes and the minimum, maximum and average prices we will receive under our outstanding derivative contracts as of September 30, 2011.

		2011		2012		2013	
		Volumes[1]	Average Price[1]	Volumes[1]	Average Price[1]	Volumes[1]	Average Price[1]
Natural Gas							
Fixed Price Swaps		39	$ 6.07	105	$ 6.01		$
Ceilings		5	$ 7.29		$		$
Floors		5	$ 6.00		$		$
Basis Swaps [2]							
Texas Gulf Coast		8	$ (0.13)		$		$
Raton		6	$ (0.25)		$		$
Oil							
Fixed Price Swaps		506	$ 87.54	640	$ 100.13		$
Ceilings			$	1,464	$ 95.00	2,920	$ 96.88
Three Way Collars	Ceiling	920	$ 94.27	5,764	$ 114.16	1,552	$ 128.34
Three Way Collars	Floors[3]	920	$ 85.14	5,764	$ 92.54	1,552	$ 100.00

(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.

(3) If market prices settle at or below $65.00, $67.54 and $75.00 for the years 2011, 2012 and 2013, respectively, our three way collars-floors effectively lock-in a cash settlement of $20.14 per Bbl for 2011 and $25.00 per Bbl for 2012 and 2013.

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,	
	2011	2010	2011	2010
	(In millions)			
Physical sales				
Natural gas	$ 256	$ 239	$ 753	$ 755
Oil and condensate	131	83	367	247
NGL	15	12	43	46
Total physical sales	402	334	1,163	1,048
Realized and unrealized gains on financial derivatives	251	184	274	468
Other revenues		1	1	19
Total operating revenues	653	519	1,438	1,535

Operating expenses				
Cost of products				15
Transportation costs	20	18	58	54
Production costs	80	61	223	194
Depreciation, depletion and amortization	157	117	437	352
General and administrative expenses	46	41	144	137
Ceiling test charges	152	14	152	16
Other	8	3	14	12
Total operating expenses	463	254	1,028	780
Operating income	190	265	410	755
Other expense[1]	(7)	(4)	(8)	(1)
Segment EBIT	$ 183	$ 261	$ 402	$ 754

(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.

37

Table of Contents

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 oil and condensate, natural gas and NGL as well as (ii) average realized prices including 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,	
	2011	2010	2011	2010
Volumes				
Natural gas (MMcf)				
Consolidated volumes	59,962	55,331	179,014	167,839
Unconsolidated affiliate volumes	4,163	4,350	12,717	12,708
Oil and condensate (MBbls)				
Consolidated volumes	1,511	1,225	4,054	3,468
Unconsolidated affiliate volumes	73	87	232	285
NGL (MBbls)				
Consolidated volumes	262	315	800	1,106
Unconsolidated affiliate volumes	142	143	422	422
Equivalent volumes				
Consolidated MMcfe	70,598	64,575	208,141	195,286
Unconsolidated affiliate MMcfe	5,457	5,729	16,643	16,948
Total combined MMcfe	76,055	70,304	224,784	212,234
Consolidated MMcfe/d	767	702	762	715
Unconsolidated affiliate MMcfe/d	60	62	61	62
Total combined MMcfe/d	827	764	823	777
Consolidated prices and costs per unit				
Natural gas ($/Mcf)				
Average realized price on physical sales	$ 4.27	$ 4.31	$ 4.21	$ 4.50
Average realized price, including financial derivative settlements (1)(2)	$ 5.60	$ 5.93	$ 5.49	$ 5.95
Average transportation costs	$ 0.32	$ 0.30	$ 0.30	$ 0.30
Oil and condensate ($/Bbl)				
Average realized price on physical sales	$ 86.73	$ 68.00	$ 90.50	$ 71.28
Average realized price, including financial derivative settlements(1)(2)	$ 88.95	$ 68.51	$ 88.77	$ 70.79
Average transportation costs	$ 0.07	$ 0.10	$ 0.06	$ 0.07
NGL ($/Bbl)				
Average realized price on physical sales	$ 56.03	$ 39.21	$ 53.59	$ 41.51
Average transportation costs	$ 3.04	$ 3.56	$ 4.28	$ 2.93
Cash operating costs ($/Mcfe)				
Average lease operating expenses	$ 0.87	$ 0.70	$ 0.77	$ 0.71
Average production taxes(3)	0.27	0.24	0.30	0.29
Average general and administrative expenses	0.65	0.63	0.69	0.70
Average taxes, other than production and income taxes	0.03	0.05	0.04	0.06

Total cash operating costs	$ 1.82	$ 1.62	$ 1.80	$ 1.76
Depreciation, depletion and amortization ($/Mcfe)[4]	$ 2.22	$ 1.81	$ 2.10	$ 1.80

(1) We had no cash premiums related to natural gas and oil derivatives settled during the quarter and nine months ended September 30, 2011. Premiums 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 premiums related to oil derivatives settled during the quarter and nine months ended September 30, 2010.

(2) The quarters ended September 30, 2011 and 2010, include approximately $80 million and $90 million of cash receipts for settlements of natural gas derivative contracts and approximately $3 million and less than $1 million of cash receipts for settlements of crude oil derivative contracts. The nine months ended September 30, 2011 and 2010, include approximately $230 million and $243 million of cash receipts for settlements of natural gas derivative contracts and approximately $7 million and $2 million of cash paid for settlements of crude oil derivative contracts.

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

(4) Includes $0.06 per Mcfe for each of the quarters ended September 30, 2011 and 2010 and $0.06 and $0.07 per Mcfe for the nine months ended September 30, 2011 and 2010 related to accretion expense on asset retirement obligations.

Quarter and Nine Months Ended September 30, 2011 Compared with Quarter and Nine Months Ended September 30, 2010

Our Segment EBIT for the quarter and nine months ended September 30, 2011 decreased $78 million and $352 million as compared to the same periods in 2010. The table below shows the significant variances of our financial results for the quarter and nine months ended September 30, 2011 as compared to the same periods in 2010:

	Quarter Ended September 30, 2011 Variance				Nine Months Ended September 30, 2011 Variance			
	Operating Revenue	Operating Expense	Other	Segment EBIT	Operating Revenue	Operating Expense	Other	Segment EBIT
	Favorable/(Unfavorable) (In millions)							
Physical sales								
Natural gas								
Lower realized prices in 2011	$ (3)	$	$	$ (3)	$ (52)	$	$	$ (52)
Higher volumes in 2011	20			20	50			50
Oil and condensate								
Higher realized prices in 2011	29			29	78			78
Higher volumes in 2011	19			19	42			42
NGL								
Higher realized prices in 2011	5			5	10			10
Lower volumes in 2011	(2)			(2)	(13)			(13)
Realized and unrealized gains (losses) on financial derivatives	67			67	(194)			(194)
Other revenues	(1)			(1)	(18)			(18)
Depreciation, depletion and amortization expense								
Higher depletion rate in 2011		(30)		(30)		(64)		(64)
Higher production volumes in 2011		(10)		(10)		(21)		(21)
Production costs								
Higher lease operating expenses in 2011		(16)		(16)		(23)		(23)
Higher production taxes in 2011		(3)		(3)		(6)		(6)
		(5)		(5)		(7)		(7)

General and administrative expenses								
Ceiling test charges		(138)		(138)		(136)		(136)
Earnings from investment in Four Star			(1)	(1)			(1)	(1)
Other		(7)	(2)	(9)		9	(6)	3
Total Variances	$ 134	$ (209)	$ (3)	$ (78)	$ (97)	$ (248)	$ (7)	$ (352)

Physical sales. Physical sales represent accrual-based commodity sales transactions with customers. During the quarter and nine months ended September 30, 2011, our revenues increased compared to the same periods in 2010, primarily as a result of higher oil and natural gas volumes and higher oil and condensate prices partially offset by lower natural gas prices. The higher volumes are due to our focus on our core programs in the Haynesville and Eagle Ford shales.

Realized and unrealized gains (losses) on financial derivatives. During the quarter and nine months ended September 30, 2011, we recognized net gains of $251 million and $274 million compared to net gains of $184 million and $468 million during the same periods in 2010. Gains or losses each period are due to changes in the fair value of our derivative contracts based on forward commodity prices relative to the prices in the underlying contracts.

Depreciation, depletion and amortization expense. During the quarter and nine months ended September 30, 2011, our depreciation, depletion and amortization expense increased as a result of a higher depletion rate and higher production volumes compared with the same periods in 2010. We expect our depreciation, depletion and amortization rate to continue to increase during the remainder of the year as we focus our capital on more liquids rich programs.

Production costs. During the quarter and nine months ended September 30, 2011, our production costs increased as compared to the same periods in 2010 primarily due to higher lease operating expenses and higher production taxes primarily associated with higher volumes. Lease operating expenses increased due to higher maintenance, repair and fuel costs in our Western division, temporary higher costs in our Southern division due to infrastructure delays in the area and higher expenses in our International division.

General and administrative expenses. During the nine months ended September 30, 2011, our general and administrative expenses increased compared to the same period in 2010, due to severance costs related to an office closure. The impact of these severance costs was approximately $5 million, or $0.02 per Mcfe on total cash operating costs.

Ceiling test charges. We are required to conduct quarterly impairment tests of our capitalized costs in each of our full cost pools. During the quarter and nine months ended September 30, 2011 we recorded a non-cash ceiling test charge of approximately $152 million in our Brazilian full cost pool. The ceiling test charge was driven by the release of costs into the Brazilian full cost pool substantially due to the recent denial of a necessary environmental permit on our Pinauna project as well as the completion of our evaluation of certain exploratory wells drilled in 2009 and 2010. We have filed an appeal with regard to the denial of the permit and are awaiting a response. 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. We may incur additional ceiling test charges in Brazil in the future depending on the value of our proved reserves, which are subject to change as a result of factors such as prices, costs and well performance. Additionally, we may incur ceiling test charges in Egypt depending on the results of our activities in that country.

Table of Contents

Marketing Segment

Our Marketing segment s primary focus is to market our Exploration and Production segment s oil and natural gas production and to manage El Paso s overall price risk. In addition, we continue to manage and liquidate certain legacy contracts. 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 2010 Annual Report on Form 10-K.

Natural gas transportation contracts. The impact of these accrual-based contracts is based on our ability to use or remarket the contracted pipeline capacity and the amount of production from our Exploration and Production segment. As of September 30, 2011, these contracts require us to pay demand charges of $18 million for the remainder of 2011 and an average of $50 million per year between 2012 and 2015.

Legacy natural gas and power contracts. As of September 30, 2011, these contracts include (i) long-term accrual-based supply contracts, including transportation expenses, that obligate us to deliver natural gas to specified power plants and (ii) power contracts in the PJM region through 2016, which we mark-to-market in our results. These contracts are expected to have minimal future impact on our earnings as we have entered into offsetting positions that eliminate the price risks associated with our PJM power contracts and substantially offset the fixed price exposure related to our natural gas supply contracts.

Operating Results

Overview. 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,	
	2011	**2010**	**2011**	**2010**
	(In millions)			
Income (Loss)				
Contracts Related to Legacy Trading Operations:				
Accrual-based contracts (including natural gas transportation):				
Demand charges	$ (15)	$ (10)	$ (37)	$ (29)
Settlements, net of termination payments	8	10	5	26
Changes in fair value of other natural gas derivative contracts		(3)	(2)	(8)
Changes in fair value of power contracts	(2)	(13)	(7)	(34)
Total revenues	(9)	(16)	(41)	(45)
Operating expenses		4	(4)	
Operating loss	$ (9)	$ (12)	$ (45)	$ (45)
Other income, net	(1)			1
Segment EBIT	$ (10)	$ (12)	$ (45)	$ (44)

During 2011 and 2010, Segment EBIT losses were primarily due to losses on transportation-related contracts and changes in the fair value of our legacy power contracts in the PJM region prior to the execution of additional offsetting positions. The first half of 2011 also includes a $22 million loss on the settlement of an affiliated fuel supply agreement which was terminated in June 2011 which was reflected as a component of settlements, net of termination payments, from accrual-based contracts.

Table of Contents

Other Activities

Our other activities include our midstream operations, corporate general and administrative functions and other miscellaneous businesses.

Midstream. As of September 30, 2011, our midstream operations consist primarily of wholly-owned assets in the Haynesville area in north Louisiana and the Eagle Ford area in south Texas, in addition to an equity investment in a joint venture that owns the Altamont natural gas gathering system and processing plant in the Uintah basin of Utah. The joint venture is currently working to expand the Altamont system, and we and our joint venture partner have each committed to make up to $500 million of future capital contributions to the joint venture for additional midstream projects to be acquired or developed by the joint venture. Our midstream business is also evaluating several larger scale projects in the Eagle Ford area, in the emerging shale plays in the Rockies, west Texas and the northeast United States.

On September 15, 2011, the open season ended to elicit binding commitments from prospective shippers interested in ethane transportation on the proposed Marcellus Ethane Pipeline System (MEPS) designed to provide transportation service from the West Virginia and Pennsylvania Marcellus shale supply areas to markets in Louisiana or Texas. The MEPS project did not receive adequate commitments from the open season to proceed at this time.

For the full year 2011, we expect to make capital expenditures and equity investments totaling approximately $90 million related to the midstream projects discussed above.

The following is a summary of significant items impacting the Segment EBIT in our other activities for the quarters and nine months ended September 30:

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(In millions)			
Income (Loss)				
Loss on debt extinguishment	$ (101)	$ (104)	$ (169)	$ (104)
Change in environmental, legal and other reserves	(28)	(18)	(52)	(16)
Midstream	(2)	2	4	5
Other	(14)	9	(28)	19
Total Segment EBIT	$ (145)	$ (111)	$ (245)	$ (96)

Loss on Debt Extinguishment. During 2011, we incurred losses primarily related to the repurchase of approximately $1.0 billion of senior unsecured notes.

Environmental, Legal and Other Reserves. We have a number of pending litigation matters and reserves related to our historical business operations that affect our results. Adverse rulings or unfavorable outcomes or settlements against us related to these matters have impacted and may continue to impact our future results. Our results for both the quarter and nine months ended September 30, 2011 and 2010 were primarily impacted by adjustments to certain legacy environmental matters, including a non-operated chemical plant and a non-operated refinery in south Texas. Also impacting these results were adjustments to certain legacy indemnifications, including an indemnification on which our liability fluctuates with ammonia prices.

Other. Our results were also impacted by gains (losses) related to our legacy power assets and exposures, foreign currency fluctuations, and benefit costs associated with certain of our post-retirement benefit plans. During the nine months ended September 30, 2010, our Segment EBIT was impacted by the refund of certain insurance premiums on legacy activities.

Table of Contents

Interest and Debt Expense

Our interest and debt expense decreased during the quarter and nine months ended September 30, 2011 as compared to the same periods in 2010 primarily associated with the exchange or repurchase of approximately $2.1 billion of debt in 2010 and through September 30, 2011 with rates from 6.875 percent to 12 percent. Interest savings associated with our liability management transactions have been partially offset by interest costs on new borrowings.

Income Taxes

	Quarters Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(In millions, except for rates)			
Income taxes	$ (130)	$ 75	$ (73)	$ 343
Effective tax rate	31%	29%	(67)%	30%

For the quarter ended September 30, 2011, our effective tax rate was impacted by the effect of a Brazilian ceiling test charge without a corresponding U.S. or Brazilian tax benefit and income attributable to nontaxable noncontrolling interests. Our negative effective tax rate for the nine months ended September 30, 2011, reflects the tax impacts of the items above, the favorable resolution of certain tax matters in the first half of 2011 and a low level of pretax income resulting from our losses on the deconsolidation of Ruby and our Brazilian ceiling test charge. Absent these items, the effective tax rate for the quarter and nine months ended September 30, 2011 would have been 29 percent and 21 percent, respectively. Our effective tax rate is expected to remain well below the statutory rate due to the earnings attributable to noncontrolling interests. In addition, in the fourth quarter of 2011 we will record a significant deferred state tax benefit of approximately $65 million due to an expected reduction to state tax rates as a result of a conversion of one of our subsidiaries to a limited liability company.

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

Commitments and Contingencies

For a further discussion of our commitments and contingencies, see Item 1, Financial Statements, Note 10, which is incorporated herein by reference and our 2010 Annual Report on Form 10-K.

Liquidity and Capital Resources

Available Liquidity and Liquidity Outlook for 2011. As of September 30, 2011 we had approximately $1.5 billion of available liquidity (exclusive of cash and credit facility capacity of EPB). During the first nine months of 2011, we (i) generated operating cash flow of approximately $1.6 billion, (ii) spent approximately $3.0 billion primarily in our capital programs, (iii) refinanced approximately $2.25 billion of our revolving credit facilities (excluding the $1.0 billion EPPOC revolving credit facility also refinanced in May 2011) to extend these maturities to 2016 and (iv) received approximately $1.4 billion in cash in conjunction with contributing additional ownership interests in SNG and CIG to our MLP which funded the acquisitions primarily through the issuance of common units and debt. As of September 30, 2011, our remaining 2011 capital expenditures are approximately $0.7 billion and our remaining 2011 debt maturities are approximately $91 million, which we will repay as they mature. Additionally, in July 2011, our unsecured $500 million credit facility matured.

Our planned 2011 capital expenditures have allowed us to place a substantial portion of our pipeline backlog in service in 2011 while continuing to support our exploration and production program. Our cash capital expenditures for the nine months ended September 30, 2011, and the amount of cash we expect to spend for the remainder of 2011 to grow and maintain our businesses are as follows:

	Nine Months Ended September 30, 2011	2011 Remaining	2011 Total
		(In billions)	
Pipelines			
Maintenance	$ 0.3	$	$ 0.3
Growth[1]	1.5	0.1	1.6
Exploration and Production	1.1	0.5	1.6
Other[2]	0.1	0.1	0.2
	$ 3.0	$ 0.7	$ 3.7

(1) Our pipeline growth capital expenditures reflect 100 percent of the capital related to the Ruby pipeline project. In September 2011, we deconsolidated Ruby and began reflecting our investment in Ruby as an investment in an unconsolidated affiliate on our balance sheet.

(2) Includes $90 million related to our midstream business.

In July 2011, the Ruby pipeline project was placed in service. In September 2011, upon making certain permitting representations and meeting certain other conditions, El Paso s guarantee of GIP s $700 million investment in Ruby and Cheyenne Plains (an entity that owns our Cheyenne Plains pipeline) expired and the Ruby project financing obligations became non-recourse to us. For a further description of this project and our agreement with GIP, see Item 1, Financial Statements, Note 15 and our 2010 Annual Report on Form 10-K .

We expect our current liquidity sources and operating cash flow will be sufficient to fund our estimated 2011 capital program and remaining 2011 debt maturities. As a result of our current available liquidity, the hedging program we have in place on our oil and natural gas production, and non-core exploration and production asset sales, we believe we are well positioned to meet our obligations. We will continue to assess and take further actions where prudent to meet our capital requirements as well as address further changes in the financial and commodity markets.

There are a number of factors that could impact our future plans, including completion of our announced merger with KMI, our ability to access the financial markets if these markets are restricted, or a further decline in commodity prices. If these events occur, or fail to occur, additional adjustments to our plan and outlook may be required, including reductions in our discretionary capital program or reductions in operating and general and administrative expenses, all of which could impact our financial and operating performance.

Table of Contents

Overview of Cash Flow Activities. During the first nine months of 2011, we generated operating cash flow of approximately $1.6 billion primarily from our pipeline and exploration and production operations. We also generated approximately $5.2 billion through the refinancing and issuance of debt, including borrowings under revolving credit facilities, and an additional $0.9 billion from the issuance of MLP common units. We used cash flow generated from these operating and financing activities primarily to fund $3.0 billion in capital expenditures under our capital programs and to make $5.0 billion in repayments under our various credit facilities and other debt obligations. For the nine months ended September 30, 2011, our cash flows are summarized as follows:

		2011 (In billions)
Cash Flow from Operations		
Operating activities		
Net income	$	0.2
Ceiling test charges		0.2
Loss on deconsolidation of subsidiary		0.6
Other income adjustments		0.8
Change in assets and liabilities		(0.2)
Total cash flow from operations	$	1.6
Other Cash Inflows		
Investing activities		
Net proceeds from the sale of assets and investments		0.6
Financing activities		
Net proceeds from the issuance of long-term debt		5.2
Net proceeds from the issuance of noncontrolling interests		0.9
Other		0.1
	$	6.2
Total other cash inflows	$	6.8
Cash Outflows		
Investing activities		
Capital expenditures		3.0
Other		0.2
	$	3.2
Financing activities		
Payments to retire long-term debt and other financing obligations		5.0
Distributions to holders of preferred stock of subsidiary and other		0.2
	$	5.2
Total cash outflows	$	8.4
Net change in cash	$	

Table of Contents

Item 3. Quantitative and Qualitative Disclosures About Market Risk

This information updates, and should be read in conjunction with the information disclosed in our 2010 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 have been no material changes in our quantitative and qualitative disclosures about market risks from those reported in our 2010 Annual Report on Form 10-K, except as presented below:

Commodity Price Risk

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 reflect 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, 2011	$ 296	$ 165	$ (131)	$ 423	$ 127
December 31, 2010	$ 237	$ 33	$ (204)	$ 434	$ 197
Other commodity-based derivatives net assets (liabilities)					
September 30, 2011	$ (341)	$ (339)	$ 2	$ (343)	$ (2)
December 31, 2010	$ (423)	$ (422)	$ 1	$ (426)	$ (3)

46

Table of Contents

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of September 30, 2011, 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, 2011.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the third quarter of 2011 that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

Table of Contents

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 2010 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;
- the satisfaction of closing conditions to the merger agreement with KMI and the completion of the proposed transactions, as well as KMI s ability to obtain adequate financing to fund the merger consideration.

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 2010 Annual Report on Form 10-K under Part I, Item 1A, Risk Factors. Below are additional risk factors as a result of the recent announcement of KMI s proposed transactions with El Paso.

Risks Related to the Proposed Transactions

Kinder Morgan and El Paso may be unable to obtain the regulatory clearances and approvals required to complete the transactions or, in order to do so, Kinder Morgan and El Paso may be required to comply with material restrictions or conditions.

The proposed transactions with Kinder Morgan that were announced on October 16, 2011 are subject to review by the Federal Trade Commission under the Hart-Scott-Rodino Act, as well as several other agencies. The closing of the transactions is also subject to the condition that there be no law, injunction, judgment or ruling by a governmental authority in effect seeking to enjoin, restrain, prevent or prohibit the transactions contemplated by the merger agreement. We can provide no assurance that all required regulatory approvals will be obtained. For example, governmental authorities could seek to block or challenge the transactions as they deem necessary or desirable in the public interest at any time, including after completion of the transactions. In addition, in some jurisdictions, a competitor, customer or other third party could initiate a private action under such jurisdiction s antitrust laws challenging or seeking to enjoin the transactions, before or after it is completed. Kinder Morgan may not prevail and may incur significant costs in defending or settling any action under the antitrust laws. Further, even if such approvals are obtained, the governmental agencies may seek to impose certain restrictions or obligations on Kinder Morgan s or El Paso s businesses as conditions for such approval, which could include requiring the divestiture of certain assets or businesses including potential divestitures of certain assets or businesses of Kinder Morgan Energy Partners, L.P. (KMP) or EPB that would require the consent of KMP or EPB, as the case may be. These actions could have the effect of delaying or preventing completion of the proposed transactions or imposing additional costs on or limiting the revenues of El Paso and the combined company following the transactions.

If Kinder Morgan s financing for the transactions is not funded, the transactions may not be completed and Kinder Morgan may be in breach of the merger agreement.

Kinder Morgan intends to finance the cash required in connection with the transactions, including for expenses incurred in connection with the transactions, with debt financing. On October 16, 2011, Kinder Morgan entered into a financing commitment letter with Barclays Capital. The commitment is subject to various conditions, including the absence of a material adverse effect on El Paso having occurred, Kinder Morgan using its commercially reasonable efforts to obtain credit ratings from S&P and Moody s, the execution of satisfactory documentation and other customary closing conditions.

In the event the financing contemplated by the commitment letter is not available, Kinder Morgan is obligated to use its best efforts to obtain alternative financing in an amount that will enable Kinder Morgan to consummate the transactions, even if such alternative financing is on less favorable terms and conditions than those contemplated by the commitment letter. Under certain circumstances, Kinder Morgan may, and El Paso may require Kinder Morgan to, sue its financing sources to specifically enforce the obligations of the financing sources under the commitment letter. Due to the fact that there is no funding condition in the merger agreement, if Kinder Morgan is unable to obtain funding from its financing sources for the cash required in connection with the transactions, Kinder Morgan could be in breach of the merger agreement assuming all other conditions to closing are not satisfied and may be liable to El Paso for damages.

We may have difficulty attracting, motivating and retaining executives and other employees in light of the transactions.

Uncertainty about the effect of the transactions on our employees may have an adverse effect on us and the combined company. This uncertainty may impair our ability to attract, retain and motivate personnel until the transactions are completed. Employee retention may be particularly challenging during the pendency of the transactions, as employees may feel uncertain about their future roles with the combined company. If our employees depart because of issues relating to the uncertainty and difficulty of integration or a desire not to become employees of the combined company, the combined company s ability to realize the anticipated benefits of the transactions could be reduced.

Pending the completion of the transactions, our business and operations could be materially adversely affected.

Under the terms of the merger agreement, we are subject to certain restrictions on the conduct of our business prior to completing the transactions which may adversely affect our ability to execute certain of our business strategies, including our ability in certain cases to enter into contracts or incur capital expenditures to grow our business. The merger agreement also restricts our ability to solicit, initiate or encourage alternative acquisition proposals with any third party and may deter a potential acquirer from proposing an alternative transaction or may limit our ability to pursue any such proposal. Such limitations could negatively affect our businesses and operations prior to the completion of the transactions. Furthermore, the process of planning to integrate two businesses and organizations for the post-merger period can divert management attention and resources and could ultimately have an adverse effect on us. In connection with the pending transactions, it is possible that some customers, suppliers and other persons with whom we have a business relationship may delay or defer certain business decisions or might decide to seek to terminate, change or renegotiate their relationship with us as a result of the transactions, which could negatively affect our revenues, earnings and cash flows, as well as the market price of shares of our common stock, regardless of whether the transactions are completed.

We will incur substantial transaction and merger-related costs in connection with the transactions.

We expect to incur a number of non-recurring transaction and merger-related costs associated with completing the transactions, combining the operations of the two companies and achieving desired synergies. These fees and costs will be substantial. Additional unanticipated costs may be incurred in the integration of the businesses of the two companies. There can be no assurance that the elimination of certain duplicative costs, as well as the realization of other efficiencies related to the integration of the two businesses, will offset the incremental transaction and merger-related costs over time. Thus, any net benefit may not be achieved in the near term, or at all.

Failure to complete the transactions could negatively affect the trading price El Paso common stock and the future business and financial results of El Paso.

Completion of the merger is not assured and is subject to risks, including the risks that approval of the transaction by the respective stockholders of Kinder Morgan and El Paso or by governmental agencies is not obtained or that other closing conditions are not satisfied. If the transactions are not completed, it could negatively affect the trading price of our common stock and the future business and financial results of El Paso, and we will be subject to several risks, including the following:

- the parties may be liable for damages to one another under the terms of the merger agreement;
- negative reactions from the financial markets, including declines in the price of our common stock due to the fact that current prices may reflect a market assumption that the transactions will be completed;
- having to pay certain significant costs relating to the merger, including, in the case of El Paso in certain circumstances, a termination fee of $650 million and up to $20 million in expenses related to the transaction, plus certain financing-related expenses of Kinder Morgan; and
- the attention of our management will have been diverted to the transactions rather than to our operations and pursuit of other opportunities that could have been beneficial to us, including the prior strategy to spin-off our exploration and production business.

Purported stockholder class action complaints have been filed against El Paso, Kinder Morgan, the members of El Paso s board of directors, El Paso s and Kinder Morgan s merger subsidiaries and Goldman Sachs, challenging the transactions, and an unfavorable judgment or ruling in these lawsuits could prevent or delay the consummation of the proposed transactions and result in substantial costs.

In connection with the proposed transactions, purported stockholders of El Paso have filed several stockholder class action lawsuits in the District Courts of Harris County, Texas and in the Delaware Courts of Chancery. Those lawsuits name as defendants El Paso, Kinder Morgan, the members of the board of directors of El Paso, and, in certain cases, the affiliates of El Paso and Kinder Morgan and Goldman Sachs. Among other remedies, the plaintiffs seek to enjoin the proposed transactions. If a final settlement is not reached, or if a dismissal is not obtained, these lawsuits could prevent or delay completion of the transactions and result in substantial costs to El Paso and Kinder Morgan, including any costs associated with the indemnification of directors. Additional lawsuits may be filed against El Paso and Kinder Morgan, their respective affiliates and El Paso s directors related to the proposed transactions. The defense or settlement of any lawsuit or claim may adversely affect the combined company s business, financial condition or results of operations.

The proposed transactions may be completed on different terms from those contained in the merger agreement.

Prior to completion of the transactions, the parties may amend or alter the terms of the merger agreement, including with respect to, among other things, the covenants of the parties regarding their business operations during the pendency of the proposed transactions or of Kinder Morgan regarding the debt financing (certain changes to the merger agreement, however, can only be made prior to the requisite stockholder approval). Any such amendments or alterations may have negative consequences to our stockholders and to our business, financial condition and results of operations.

Closing of the proposed transactions may trigger change in control provisions in certain agreements to which we are a party.

Closing of the proposed transactions may trigger change in control provisions in certain agreements to which we are parties. If we are unable to negotiate waivers of those provisions, the counterparties may exercise their rights and remedies under the agreements, potentially terminating the agreements or seeking monetary damages. Even if we are able to negotiate waivers, the counterparties may require a fee for such waiver or seek to renegotiate the agreements on less favorable terms. As a result of the announcement of the transactions, we were placed on negative outlook by Moody s and Fitch. During the pendency of the proposed transactions, a decrease in Kinder Morgan s perceived creditworthiness may have an adverse effect on our perceived creditworthiness, possibly resulting in a downgrade of credit ratings, tightening of credit under our existing credit facilities, increasing our borrowing costs or, upon completion of the transactions with KMI, could trigger certain change of control provisions to certain agreements to which we are a party.

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.

Table of Contents

SIGNATURES

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

	EL PASO CORPORATION
Date: November 4, 2011	/s/ John R. Sult John R. Sult Executive Vice President and Chief Financial Officer (Principal Financial Officer)
Date: November 4, 2011	/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
2.1	Agreement and Plan of Merger, dated as of October 16, 2011, by and among El Paso Corporation, Sirius Holdings Merger Corporation, Sirius Merger Corporation, Kinder Morgan, Inc., Sherpa Merger Sub, Inc and Sherpa Acquisition, LLC (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K filed with the SEC on October 18, 2011).
2.2	Agreement and Plan of Merger, dated as of October 16, 2011, by and among El Paso Corporation, Sirius Holdings Merger Corporation and Sirius Merger Corporation (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K filed with the SEC on October 18, 2011).
10.1	Voting Agreement, dated as of October 16, 2011, by and among El Paso Corporation, Richard D. Kinder, GS Capital Partners V Fund, L.P., GSCP V Offshore Knight Holdings, L.P., GSCP V Germany Knight Holdings, L.P., GS Capital Partners V Institutional, L.P., GS Capital Partners VI Fund, L.P., GSCP VI Offshore Knight Holdings, L.P., GSCP VI Germany Knight Holdings, L.P., GS Capital Partners VI Parallel, L.P., Goldman Sachs KMI Investors, L.P., GSCP KMI Investors, L.P., GSCP KMI Investors Offshore, L.P., GS Infrastructure Knight Holdings, L.P., GS Infrastructure Partners, I, L.P., GS Global Infrastructure Partners I, L.P., Highstar II Knight Acquisition Sub, L.P., Highstar III Knight Acquisition Sub, L.P., Highstar Knight Partners, L.P., Highstar KMI Blocker LLC, Carlyle Partners IV Knight, L.P., CP IV Coinvestment, L.P., Carlyle Energy Coinvestment III, L.P., Carlyle/Riverstone Knight Investment Partnership, L.P., C/R Knight Partners, L.P., C/R Energy III Knight Non-U.S. Partnership, L.P., and Riverstone Energy Coinvestment III, L.P. Corporation (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K filed with the SEC on October 18, 2011).
*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.