EL PASO CORP/DE
Form 10-Q
May 04, 2012
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2012

OR

¨ **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	**45-3953911**
(State or Other Jurisdiction of	**(I.R.S. Employer**
Incorporation or Organization)	**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 x No ¨

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 x No ¨

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 x	Accelerated filer ¨
Non-accelerated filer ¨ (Do not check if a smaller reporting company)	Smaller reporting company ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x

Indicate the number of shares outstanding of each of the issuer s classes of common stock, as of the latest practicable date.

Common stock, par value $3 per share. Shares outstanding on May 2, 2012: 774,039,108

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

/d	= per day
Bbl	= barrels
BBtu	= billion British thermal units
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/or our subsidiaries.

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PART I FINANCIAL INFORMATION

Item 1. Financial Statements

EL PASO CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(In millions, except per common share amounts)

(Unaudited)

	$xxx,xxx	$xxx,xxx
	Quarter Ended March 31,	
	2012	**2011**
Operating revenues	$ 1,260	$ 989
Operating expenses		
Cost of products and services	54	47
Operation and maintenance	338	305
Ceiling test charges	62	
Depreciation, depletion and amortization	330	254
Taxes, other than income taxes	82	76
	866	682
Operating income	394	307
Earnings from unconsolidated affiliates	35	30
Loss on debt extinguishment		(41)
Other income, net	16	99
Interest and debt expense	(226)	(240)
Income before income taxes	219	155
Income tax expense	70	19
Net income	149	136
Net income attributable to noncontrolling interests	(63)	(74)
Net income attributable to El Paso Corporation	$ 86	$ 62
Basic earnings per common share		
Net income attributable to El Paso Corporation	$ 0.11	$ 0.09
Diluted earnings per common share		
Net income attributable to El Paso Corporation	$ 0.11	$ 0.08
Dividends declared per El Paso Corporation s common share	$ 0.01	$ 0.01

See accompanying notes.

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EL PASO CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(In millions)

(Unaudited)

	$xxx,xxx	$xxx,xxx
	Quarter Ended March 31,	
	2012	**2011**
Net income	$ 149	$ 136
Pension and postretirement obligations:		
Reclassification of net actuarial losses during period (net of income taxes of $7 in both 2012 and 2011)	14	16
Cash flow hedging activities:		
Unrealized mark-to-market (losses) gains arising during period (net of income taxes of $5 in 2012 and $2 in 2011)	(5)	3
Reclassification adjustments for amounts recognized during the period (net of income taxes of $2 in 2012 and $1 in 2011)	2	3
Other comprehensive income	11	22
Comprehensive income	160	158
Comprehensive income attributable to noncontrolling interests	(63)	(74)
Comprehensive income attributable to El Paso Corporation	$ 97	$ 84

See accompanying notes.

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EL PASO CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

(In millions, except share and per share amounts)

(Unaudited)

	March 31, 2012	December 31, 2011
ASSETS		
Current assets		
Cash and cash equivalents	$ 305	$ 194
Accounts receivable		
Customer, net of allowance of $2 in both 2012 and 2011	313	331
Affiliates	41	36
Other	158	192
Notes receivable from affiliates	113	85
Materials and supplies	174	175
Assets from price risk management activities	283	282
Deferred income taxes	74	127
Other	154	155
Total current assets	1,615	1,577
Property, plant and equipment, at cost		
Pipelines	19,939	19,931
Oil and natural gas properties, at full cost	22,373	22,070
Other	528	529
	42,840	42,530
Less accumulated depreciation, depletion and amortization	23,569	23,360
Total property, plant and equipment, net	19,271	19,170
Other long-term assets		
Investments in unconsolidated affiliates	2,742	2,739
Assets from price risk management activities	26	20
Other	724	808
	3,492	3,567
Total assets	$ 24,378	$ 24,314

See accompanying notes.

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EL PASO CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

(In millions, except share and per share amounts)

(Unaudited)

	March 31, 2012	December 31, 2011
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 344	$ 415
Affiliates	13	12
Other	374	409
Short-term financing obligations, including current maturities	361	362
Liabilities from price risk management activities	129	140
Asset retirement obligations	57	39
Accrued interest	233	184
Other	425	587
Total current liabilities	1,936	2,148
Long-term financing obligations, less current maturities	12,620	12,605
Other long-term liabilities		
Liabilities from price risk management activities	275	284
Deferred income taxes	633	612
Other	1,632	1,530
	2,540	2,426
Commitments and contingencies (Note 8)		
Equity		
El Paso Corporation stockholders equity:		
Common stock, par value $3 per share; authorized 1,500,000,000 shares; issued 788,493,799 shares in 2012 and 787,316,201 shares in 2011	2,366	2,362
Additional paid-in capital	5,392	5,364
Accumulated deficit	(2,207)	(2,293)
Accumulated other comprehensive loss	(785)	(796)
Treasury stock (at cost); 14,394,293 shares in 2012 and 15,081,177 shares in 2011	(270)	(283)
Total El Paso Corporation stockholders equity	4,496	4,354
Noncontrolling interests	2,786	2,781
Total equity	7,282	7,135
Total liabilities and equity	$ 24,378	$ 24,314

See accompanying notes.

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EL PASO CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions)

(Unaudited)

	Quarter Ended March 31, 2012	Quarter Ended March 31, 2011
Cash flows from operating activities		
Net income	$ 149	$ 136
Adjustments to reconcile net income to net cash from operating activities:		
Depreciation, depletion and amortization	330	254
Ceiling test charges	62	
Deferred income tax expense	69	26
Earnings from unconsolidated affiliates, adjusted for cash distributions	(25)	(18)
Loss on debt extinguishment		41
Other non-cash income items	15	(64)
Asset and liability changes	(84)	156
Net cash provided by operating activities	516	531
Cash flows from investing activities		
Capital expenditures	(509)	(1,089)
Repayment of notes receivable	37	1
Other	15	(1)
Net cash used in investing activities	(457)	(1,089)
Cash flows from financing activities		
Net proceeds from issuance of debt and other financing obligations	540	806
Payments to retire long-term debt and other financing obligations	(526)	(794)
Proceeds from transfer of assets to unconsolidated affiliate	89	
Net proceeds from issuance of noncontrolling interests		457
Net proceeds from issuance of preferred stock of subsidiary		30
Dividends paid	(8)	(16)
Distributions to noncontrolling interest holders	(58)	(39)
Distributions to holders of preferred stock of subsidiary		(5)
Other	15	14
Net cash provided by financing activities	52	453
Change in cash and cash equivalents	111	(105)
Cash and cash equivalents		
Beginning of period	194	347
End of period	$ 305	$ 242

See accompanying notes.

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EL PASO CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF EQUITY

(In millions)

(Unaudited)

	Quarter Ended March 31, 2012	Quarter Ended March 31, 2011
El Paso Corporation stockholders equity:		
Preferred stock:		
Balance at beginning of period	$	$ 750
Conversion of preferred stock		(750)
Balance at end of period		
Common stock:		
Balance at beginning of period	2,362	2,159
Conversion of preferred stock		174
Other, net	4	4
Balance at end of period	2,366	2,337
Additional paid-in capital:		
Balance at beginning of period	5,364	4,484
Conversion of preferred stock		576
Dividends	(8)	(7)
Issuances of noncontrolling interests		170
Stock-based compensation and other	36	23
Balance at end of period	5,392	5,246
Accumulated deficit:		
Balance at beginning of period	(2,293)	(2,434)
Net income attributable to El Paso Corporation	86	62
Balance at end of period	(2,207)	(2,372)
Accumulated other comprehensive income (loss):		
Balance at beginning of period	(796)	(751)
Other comprehensive income attributable to El Paso Corporation	11	22
Balance at end of period	(785)	(729)
Treasury stock, at cost:		
Balance at beginning of period	(283)	(291)
Stock-based and other compensation	13	19
Balance at end of period	(270)	(272)

Total El Paso Corporation stockholders equity at end of period	4,496	4,210
Noncontrolling interests:		
Balance at beginning of period	2,781	2,147
Issuances of noncontrolling interests		287
Distributions to noncontrolling interests	(58)	(39)
Net income attributable to noncontrolling interests	63	52
Balance at end of period	2,786	2,447
Total equity at end of period	$ 7,282	$ 6,657

See accompanying notes.

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EL PASO CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 2011 Annual Report on Form 10-K. The financial statements as of March 31, 2012, and for the quarters ended March 31, 2012 and 2011, are unaudited. The condensed consolidated balance sheet as of December 31, 2011, was derived from the audited balance sheet filed in our 2011 Annual Report on Form 10-K. In our opinion, we have made adjustments, all of which are of a normal, recurring nature to fairly present our interim period results. Due to the seasonal nature of our businesses, information for interim periods may not be indicative of our operating results for the entire year. Our disclosures in this Form 10-Q are an update to those provided in our 2011 Annual Report on Form 10-K.

Proposed Merger with Kinder Morgan, Inc.

In October 2011, we entered into a definitive merger agreement (the merger agreement) with Kinder Morgan, Inc. (KMI) whereby KMI will acquire El Paso Corporation (El Paso) in a transaction that valued El Paso at approximately $38 billion (based on the KMI stock price at that date), including the assumption of debt. In March 2012, both our and KMI s stockholders approved the merger agreement and a series of transactions to effectuate the merger. As part of these transactions, on March 26, 2012, the common stockholders of El Paso Corporation (Old El Paso) became common stockholders of a new corporation (New El Paso); Old El Paso became a direct, wholly owned subsidiary of New El Paso; and New El Paso became the public reporting company as the successor issuer of Old El Paso (the predecessor for historical accounting purposes) for purposes of SEC filings. In conjunction with these transactions, Old El Paso was also converted into a Delaware limited liability company (renamed El Paso LLC) and New El Paso was renamed El Paso Corporation. New El Paso also entered into supplemental indentures whereby it guaranteed each of Old El Paso s outstanding indentures and debt securities issued thereunder and assumed the obligations under Old El Paso s Trust Preferred Securities and the underlying Subordinated Convertible Debentures as further described in Note 7. The reorganization had no impact on the reported amounts in these financial statements.

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 percent of the aggregate merger consideration (excluding the warrants) is paid in cash and approximately 43 percent (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.

The merger agreement includes customary representations, warranties and covenants, and specific agreements relating to (i) the conduct of each of El Paso s and KMI s respective businesses between the date of the signing of the merger agreement and the closing of the merger transactions and (ii) the efforts of the parties to cause the merger transactions to be completed. In addition to certain other covenants, we have agreed not to encourage, solicit, initiate or facilitate any takeover proposal from a third party or enter into any agreement, arrangement or understanding requiring us to abandon, terminate or fail to consummate the merger and related transactions. The merger agreement contains certain termination rights for both El Paso and KMI.

Under the terms of the merger agreement, we have agreed to conduct our business in the ordinary course and in all material respects in substantially the same manner as conducted prior to the date of the merger agreement, subject to certain conditions, restrictions and thresholds including, but not limited to, our ability to (i) commit to capital expenditures above our current capital budgets (ii) acquire, invest in, or dispose of any material properties, assets, or equity interests as defined in the merger agreement (iii) incur new debt, refinance, or guarantee any debt or borrowed money, (iv) enter into, terminate, or amend certain material contracts, (v) issue, grant, sell, or redeem new El Paso capital stock or stock-based compensation awards and/or pay dividends in excess of $0.01/share, among other limitations.

The completion of the merger transactions constitutes a change of control for El Paso that may trigger provisions in certain agreements including those related to (i) debt and other financing agreements, (ii) severance agreements and (iii) incentive compensation plan agreements that will result in an immediate acceleration of all unvested stock based compensation awards upon completion of the merger transactions. For our debt and other financing agreements containing covenants related to change in control events and that will not be terminated pursuant to the merger, we have either amended the agreements or obtained waivers of those covenants. However, if there was a downgrade of our credit ratings it could trigger certain other change of control provisions to certain agreements to which we are a party.

In conjunction with the merger agreement, KMI announced that they intend to sell our exploration and production assets. On February 24, 2012, we entered into a purchase and sale agreement to sell all of our exploration and production assets to an affiliate of Apollo Global Management, LLC (Apollo) and certain other parties for $7.15 billion subject to certain adjustments for items such as contributions or distributions, incurrence of debt and title defects. The closing of the sale of these assets is conditioned upon completion of the merger transactions with KMI. The purchase and sale agreement contains customary representations and warranties relating to the exploration and production assets and operations. Additionally, El Paso has entered into a performance guarantee in favor of Apollo, under which we guarantee the performance of all of our seller subsidiaries obligations under the purchase and sale agreement. Pursuant to the merger agreement with KMI, KMI is required to indemnify us from any and all cost incurred by us arising from or relating to the sale of the exploration and production assets. Upon completion of the sale to Apollo, the exploration and production business will be reflected as a discontinued operation in our financial statements.

On May 1, 2012, KMI announced that it received approval from the Federal Trade Commission (FTC) for the merger, subject to the previously announced divestiture of certain assets. We expect remaining required regulatory approvals, shareholder consideration elections and other remaining transactions contemplated in conjunction with the KMI merger, including the sale of our exploration and production assets, to be completed by the end of May 2012.

Significant Accounting Policies

There were no changes in the significant accounting policies described in our 2011 Annual Report on Form 10-K and no significant accounting pronouncements issued but not yet adopted as of March 31, 2012.

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2. 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 ended March 31, 2012, we recorded a non-cash charge of approximately $62 million as a result of our decision to no longer explore or develop our acreage in Egypt. The charge principally relates to unevaluated costs in that country, but also includes approximately $2 million related to equipment. On April 30, 2012, we entered into a purchase and sale agreement to sell all our interests in Egypt. The sale will represent an exit from our Egyptian exploration activities. We may incur 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.

3. Other Income, Net

The following are the components of other income and other expenses for the quarters ended March 31:

	2012	2011
	(In millions)	
Other Income		
Allowance for equity funds used during construction	$ 5	$ 97
Other	12	7
Total	$ 17	$ 104
Other Expenses		
Other	$ 1	$ 5
Total	1	5
Other income, net	$ 16	$ 99

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.

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4. Income Taxes

Income taxes for the quarters ended March 31 were as follows:

	2012	2011
	(In millions, except rates)	
Income tax expense	$ 70	$ 19
Effective tax rate	32%	12%

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.

During the first quarter of 2012, our effective tax rate was lower than the statutory rate primarily due to income attributable to nontaxable noncontrolling interests and dividend exclusions on earnings from unconsolidated affiliates where we anticipate receiving dividends. Partially offsetting these items was the impact of an Egyptian ceiling test charge without a corresponding tax benefit. A tax benefit of approximately $40 million associated with the anticipated capital loss on the sale of our interests in Egypt will be recorded in the second quarter of 2012 consistent with the timing of our board s approval of the transaction. For a discussion of our ceiling test charges, see Note 2.

For the first quarter of 2011, our effective tax rate was lower than the statutory rate due to income attributable to nontaxable noncontrolling interests, dividend exclusions on earnings from unconsolidated affiliates where we anticipate receiving dividends, the resolution of several tax matters and earned state tax credits.

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 $80 million over the next 12 months as a result of the anticipated favorable resolution of certain tax matters.

5. Earnings Per Share

Basic and diluted earnings per common share were as follows for the quarters ended March 31:

	2012		2011	
	Basic	Diluted	Basic	Diluted
	(In millions, except per share amounts)			
Net income attributable to El Paso Corporation	$ 86	$ 86	$ 62	$ 62
Weighted average common shares outstanding	767	767	714	714
Effect of dilutive securities:				
Stock-based awards		14		10
Convertible preferred stock				44
Weighted average common shares outstanding and dilutive securities	767	781	714	768
Basic and diluted earnings per common share:				
Net income attributable to El Paso Corporation	$ 0.11	$ 0.11	$ 0.09	$ 0.08

We exclude potentially dilutive securities from the determination of diluted earnings per share (as well as their related income statement impacts) when their impact on net income attributable to El Paso Corporation per common share is antidilutive. Potentially dilutive securities consist of stock based awards (employee stock options, restricted stock and performance shares), convertible preferred stock and trust preferred securities. In March 2011, we converted our preferred stock to common stock. For the quarters ended March 31, 2012 and 2011, our trust preferred securities and certain of our employee stock options were antidilutive.

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6. Financial Instruments

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

	March 31, 2012		December 31, 2011	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Long-term financing obligations, including current maturities	$ 12,981	$ 14,277	$ 12,967	$ 14,242
Marketable securities in non-qualified compensation plans	20	20	20	20
Commodity-based derivatives	(82)	(82)	(110)	(110)
Interest rate derivatives	(13)	(13)	(12)	(12)
Other	(3)	(3)	1	1

We estimated the fair value of our long-term financing obligations (representing a Level 2 fair value measurement) primarily based on quoted market prices for the same or similar issuances, including consideration of our credit risk related to those instruments. As of March 31, 2012 and December 31, 2011, the carrying amounts of cash and cash equivalents, accounts receivable and accounts payable represent fair value based on the short-term nature of these instruments. The carrying amounts of our restricted cash and noncurrent receivables approximate their fair value based on an analysis of the nature of their interest rates and our assessment of the ability to recover these amounts.

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 and would be reflected at the end of the period in which the change occurs. During the quarter ended March 31, 2012, 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. On certain derivative contracts recorded as assets in the table below, we are exposed to the risk that our counterparties may not perform or post the required collateral.

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The following table presents the fair value of our financial instruments at March 31, 2012 and December 31, 2011 (in millions).

	March 31, 2012				December 31, 2011			
	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	$	$ 342	$	$ 342	$	$ 304	$	$ 304
Other natural gas derivatives		96	10	106		57	12	69
Power-related derivatives			19	19			6	6
Total commodity-based derivative assets		438	29	467		361	18	379
Interest rate derivatives designated as hedges								
Fair value hedges		1		1		2		2
Impact of master netting arrangements		(143)	(16)	(159)		(76)	(3)	(79)
Total price risk management assets [1]	$	$ 296	$ 13	$ 309	$	$ 287	$ 15	$ 302
Marketable securities in non-qualified compensation plans[2]	20			20	20			20
Total net assets	$ 20	$ 296	$ 13	$ 329	$ 20	$ 287	$ 15	$ 322
Liabilities								
Commodity-based derivatives								
Production-related oil and natural gas derivatives	$	$ (144)	$	$ (144)	$	$ (103)	$	$ (103)
Other natural gas derivatives		(132)		(132)		(111)		(111)
Power-related derivatives			(273)	(273)			(275)	(275)
Total commodity-based derivative liabilities		(276)	(273)	(549)		(214)	(275)	(489)
Interest rate derivatives designated as hedges								
Cash flow hedges		(14)		(14)		(14)		(14)
Impact of master netting arrangements		143	16	159		76	3	79
Total price risk management liabilities [1]	$	$ (147)	$ (257)	$ (404)	$	$ (152)	$ (272)	$ (424)
Other[2]			(6)	(6)			(10)	(10)
Total net liabilities	$	$ (147)	$ (263)	$ (410)	$	$ (152)	$ (282)	$ (434)
Total	$ 20	$ 149	$ (250)	$ (81)	$ 20	$ 135	$ (267)	$ (112)

(1) Our price risk management assets and liabilities are netted for counterparties where we have a legal right of offset and classified as either current or non-current assets or liabilities based on their anticipated settlement date. At March 31, 2012 and December 31, 2011, cash collateral held was not material.

(2) Reflected on our balance sheets as other long-term assets and other current liabilities, as applicable.

Our derivative financial instruments in the table above are further described in our 2011 Annual Report on Form 10-K and below:

Production-Related Commodity Based Derivatives. As of March 31, 2012 and December 31, 2011, we have production-related derivatives (oil and natural gas swaps, 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 35,850 MBbl and 14,530 MBbl of oil and 286 TBtu and 105 TBtu of natural gas. None of these contracts are designated as accounting hedges.

Other Commodity-Based Derivatives. As of March 31, 2012 and December 31, 2011, in our Marketing segment we have forwards and swaps 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. None of these derivatives are designated as accounting hedges. 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.

Our Level 3 natural gas derivatives are valued primarily based upon forward NYMEX gas curves and forward gas basis curves for the next five years received from third-party providers. For those periods beyond five years for which gas basis curves are not available, we develop our gas basis curves by calculating a NYMEX-to-basis ratio for the last two years received from third-party providers (2016 and 2017), and then multiply this ratio times the NYMEX forward curves beyond the five year period, to derive the remaining forward basis curves. On average, the basis curves for our Level 3 natural gas derivatives beyond five years are within 2 percent to 3 percent of the NYMEX forward curves for the same periods.

Our Level 3 power-related derivatives are primarily in the PJM markets and valued based upon price quotes received from third-party providers. As the delivery points in our contracts are in an illiquid market and are not actively traded, we adjust the PJM forward curves by the difference between the 12-month rolling average of actual settled prices at delivery points in the PJM East region. The adjusted prices over the contract term ranged from $23.59 per MW/h to $61.01 per MW/h.

Significant changes in any of the unobservable inputs used in the fair value measurement of these or other Level 3 instruments can result in a lower or higher fair value measurement; however, due to the offsetting positions mentioned above, such changes are not expected to have a significant impact on our results of operations.

Interest Rate Derivatives. We have long-term debt with variable interest rates that exposes us to changes in market-based interest rates. As of March 31, 2012 and December 31, 2011, we had interest rate swaps that are designated as cash flow hedges that effectively convert the interest rate on approximately $141 million and $144 million of debt from a floating LIBOR interest rate to a fixed interest rate.

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 March 31, 2012 and December 31, 2011, these interest rate swaps converted the interest rate on approximately $162 million of debt from a fixed rate to a variable rate of LIBOR plus 4.18 percent.

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The following table presents the changes in our financial assets and liabilities included in Level 3 for the quarter ended March 31, 2012 (in millions):

	Balance at Beginning of Period	Change in Fair Value Reflected in Operating Revenues(1)	Change in Fair Value Reflected in Operating Expenses(2)	Settlements	Balance at End of Period
Assets	$ 15	$ (2)	$	$	$ 13
Liabilities	(282)	(2)	2	19	(263)
Total	$ (267)	$ (4)	$ 2	$ 19	$ (250)

(1) Includes approximately $5 million of net losses that had not been realized through settlements as of March 31, 2012.
(2) Includes approximately $1 million of net gains that had not been realized through settlements as of March 31, 2012.

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 ended March 31:

	2012			2011		
	Operating Revenues	Interest Expense	Other Comprehensive Income	Operating Revenues	Interest Expense	Other Comprehensive Income
			(In millions)			
Production-related derivatives	$ 76	$	$ 3	$ (109)	$	$ 3
Other natural gas and power derivatives not designated as hedges	(3)			(1)		
Interest rate derivatives(1)		3	1		4	3
Total	$ 73	$ 3	$ 4	$ (110)	$ 4	$ 6

(1) No ineffectiveness was recognized on our interest rate hedges for the quarters ended March 31, 2012 and 2011.

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7. Debt, Other Financing Obligations and Other Credit Facilities

	March 31, 2012	December 31, 2011
	(In millions)	
Short-term financing obligations, including current maturities	$ 361	$ 362
Long-term financing obligations	12,620	12,605
Total	$ 12,981	$ 12,967

Changes in Financing Obligations. During the quarter ended March 31, 2012, we had the following changes in our financing obligations:

Company	Interest Rate	Book Value Increase (Decrease)	Cash Received (Paid)
		(In millions)	
Issuances			
El Paso revolving credit facility	variable	$ 365	$ 365
EP Energy, L.L.C. (EPE) revolving credit facility	variable	175	175
Increases through March 31, 2012		$ 540	$ 540
Repayments, repurchases, and other			
El Paso revolving credit facility	variable	$ (455)	$ (455)
EPE revolving credit facility	variable	(65)	(65)
Other	various	(6)	(6)
Decreases through March 31, 2012		$ (526)	$ (526)

Repurchase of Senior Notes. In March 2011, we repurchased $148 million of notes and recorded a loss on debt extinguishment of approximately $41 million.

Credit Facilities/Letters of Credit. We have various credit facilities in place which allow us to borrow funds or issue letters of credit. We enter into letters of credit and issue surety bonds in the ordinary course of our operating activities as well as periodically in conjunction with the sales of assets or businesses. As of March 31, 2012, the aggregate amount of borrowings outstanding under all of our credit facilities was $1.5 billion. In addition, we had $0.5 billion of letters of credit and surety bonds outstanding at March 31, 2012, including approximately $0.3 billion related to our price risk management activities. Our total available capacity under all of our facilities was approximately $0.9 billion as of March 31, 2012 (not including capacity available under the El Paso Pipeline Partners Operating Company, L.L.C. $1.0 billion revolving credit facility). In April 2012, a $50 million letter of credit facility matured.

The availability of borrowings under our credit agreements and our ability to incur additional debt is subject to various financial and non-financial covenants and restrictions. There have been no significant changes to our restrictive covenants, and as of March 31, 2012, we were in compliance with all of our debt covenants. For a further discussion of our credit facilities and restrictive covenants, see our 2011 Annual Report on Form 10-K.

Other. In March 2012, in connection with the merger transactions described in Note 1, New El Paso (which was renamed El Paso Corporation) entered into supplemental indentures under each of Old El Paso s outstanding indentures by which New El Paso agreed to irrevocably and unconditionally guarantee Old El Paso s obligations totaling approximately $4.1 billion at that time. In addition, New El Paso entered into a supplemental indenture and assumption agreement related to Old El Paso s Trust Preferred Securities and related agreements and the underlying Subordinated Convertible Debentures due 2028 totaling $325 million. Old El Paso is a wholly owned subsidiary of New El Paso whose senior notes are guaranteed fully and unconditionally by New El Paso. Additionally, other than its wholly owned investment in Old El Paso and obligations under the Trust Preferred Securities obligations, New El Paso has no other significant operations. As further described in our Form 10-K, we are subject to certain debt covenant or subsidiary partnership agreement provisions. Subject to these customary provisions, there are no significant restrictions on New El Paso s ability to access the net assets or cash flows related to its interests in Old El Paso either through dividend or loan.

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8. Commitments and Contingencies

Legal Proceedings

Shareholder Class Actions. Since October 2011, twenty-one purported shareholder class actions have been 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. Eight of the actions were filed and consolidated in state district court in Harris County, Texas, and thirteen were filed and consolidated in Delaware Chancery Court. In February 2012, the Delaware Chancery Court denied the plaintiffs motion to enjoin the transaction. A trial is scheduled to commence in early March 2013. An additional purported class action lawsuit was filed on behalf of unitholders of El Paso Pipeline Partners, L.P. (EPB) in the Delaware Chancery Court in December 2011 against El Paso and its board of directors. The lawsuit alleges that the merger transaction with KMI adversely affected the unitholders of EPB and that El Paso and its board of directors breached their fiduciary duties. A motion to dismiss that suit has been filed. We believe these purported shareholder class actions are without merit and we intend to defend against them vigorously.

Brinckerhoff Lawsuits. In December 2011, a derivative lawsuit was filed on behalf of EPB against us and the board of directors of the general partner of EPB associated with a transaction completed in March 2010 involving the sale of interests in Southern LNG Company, L.L.C. (SLNG) and Elba Express Company, L.L.C. (Elba Express) to EPB. In March 2012, a second derivative lawsuit was filed on behalf of EPB against us and the board of directors of the general partner of EPB associated with a transaction completed in November 2010 involving the sale of interests in SLNG, Elba Express, and Southern Natural Gas (SNG) to EPB. These lawsuits allege various conflicts of interest and that the consideration paid in those transactions by EPB was excessive. We believe these actions are without merit and we intend to defend against them vigorously.

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. Ninety-seven of the cases have been settled or dismissed, and most of the settlements have been substantially funded by insurance. We have two remaining lawsuits, both pending in the MDL. 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. Therefore, our costs and legal exposure related to these remaining lawsuits are not currently determinable.

Other. In addition to the above proceedings, we and our subsidiaries and affiliates are named defendants in numerous lawsuits and governmental proceedings and claims that arise in the ordinary course of our business. There are also other regulatory rules and orders in various stages of adoption, review and/or implementation. For each of these matters, we evaluate the merits of the case or claim, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we establish the necessary accruals. While the outcome of these matters, including those discussed above, cannot be predicted with certainty, and there are still uncertainties related to the costs we may incur, based upon our evaluation and experience to date, we believe we have established appropriate reserves for these matters. It is possible, however, that new information or future developments could require us to reassess our potential exposure related to these matters and adjust our accruals accordingly, and these adjustments could be material. As of March 31, 2012, we had approximately $40 million accrued for all of our outstanding legal proceedings.

Rates and Regulatory Matters

El Paso Natural Gas (EPNG) Rate Case. In April 2010, the FERC approved an offer of settlement of EPNG s rate case which increased its 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 revenues 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 and concluded in December 2011. A decision is due in May 2012. It is uncertain whether such an increase will be achieved in the context of any settlement between EPNG and its customers or following the outcome of the hearing in the rate case. Although the final outcome of this matter is not currently determinable, we believe our accruals established for this matter are adequate.

Tennessee Gas Pipeline (TGP) Rate Case. In December 2011, the FERC approved TGP s settlement that resolved the outstanding issues arising from its general rate case filing. As part of the settlement, TGP refunded approximately $69 million, including interest, to its customers in March 2012. For a further discussion of TGP s rate case settlement, see our 2011 Annual Report on Form 10-K.

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 March 31, 2012, we had accrued approximately $188 million for environmental matters, which has not been reduced by $18 million for amounts to be paid directly under government sponsored programs or through settlement arrangements with third parties. Our accrual includes approximately $185 million for expected remediation costs and associated onsite, offsite and groundwater technical studies and approximately $3 million for related environmental legal costs.

Our estimates of potential liability range from approximately $188 million to approximately $329 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:

	March 31, 2012	
Sites	**Expected**	**High**
	(In millions)	
Operating	$ 7	$ 11
Non-operating	167	281
Superfund	14	37
Total	$ 188	$ 329

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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 issues are included in the previously indicated estimates for Superfund sites.

For the remainder of 2012, we estimate that our total remediation expenditures will be approximately $57 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 $22 million in the aggregate for the remainder of 2012 through 2016, including capital expenditures associated with the impact of the U.S. Environmental Protection Agency s (EPA) 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.

On April 17, 2012, the EPA issued regulations pursuant to the federal Clean Air Act to reduce various air pollutants from the oil and natural gas industry. These regulations will limit emissions from the hydraulic fracturing of certain natural gas wells and from certain equipment including compressors, storage vessels and natural gas processing plants. We are still evaluating the regulations and their impact on our operations and our financial results.

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 $710 million, which is comprised of a $438 million indemnification associated with the sale of ANR Pipeline Company (ANR), a $120 million indemnification associated with the sale of our Macae power facility in Brazil, and $152 million of indemnifications and guarantees related to the sale of other legacy assets. These amounts exclude guarantees for which we have issued related letters of credit. Included in the above maximum stated value are certain indemnification agreements that have expired; however, claims were made prior to the expiration of the related claim periods. We are unable to estimate a maximum exposure of our guarantee and indemnification agreements that do not provide for limits on the amount of future payments due to the uncertainty of these exposures.

As of March 31, 2012, we have recorded obligations of $11 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.

Other Commitments. In 2009, the FERC approved an amendment to the 1995 FERC settlement with TGP that provides for interim refunds over a three year period of approximately $157 million plus interest of 8% for amounts collected related to certain environmental costs. Through March 31, 2012, TGP has refunded approximately $158 million, including interest, to its customers. The remaining refund obligations of approximately $20 million, including interest, (recorded as other current liabilities on our balance sheet at March 31, 2012) were refunded to its customers in April 2012.

For a further discussion of our guarantees, indemnifications, purchase obligations, and other commitments see our 2011 Annual Report on Form 10-K.

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9. Retirement Benefits

Components of Net Benefit Cost. For each of the quarters ended March 31, the components of net benefit cost are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2012	2011	2012	2011
	(In millions)			
Service cost	$ 6	$ 5	$	$
Interest cost	24	26	6	8
Expected return on plan assets	(38)	(36)	(4)	(4)
Amortization of net actuarial loss	22	23		
Amortization of prior service cost (credit)	1		(2)	
Net benefit cost	$ 15	$ 18	$	$ 4

10. Equity and Noncontrolling Interests

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

	Common Stock ($0.01/Share)
Amount paid through March 31, 2012	$ 8
Amount paid in April 2012	$ 8

Dividends on our common stock are treated as a reduction of additional paid-in-capital since we currently have an accumulated deficit. We expect dividends paid in 2012 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 Note 1 and our 2011 Annual Report on Form 10-K.

Noncontrolling Interest in EPB. We are the general partner of EPB, a master limited partnership (MLP). As of March 31, 2012, we own a 44 percent interest in EPB (a 2 percent general partner interest and a 42 percent limited partner interest).

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 hold as the general partner. Prior to February 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 in February 2011 into common units on a one-for-one basis effective as of January 3, 2011. During the first quarter of 2011, EPB issued 13.8 million common units for $457 million in conjunction with the contribution of an additional 25 percent ownership interest in Southern Natural Gas Company, L.L.C. Our consolidated statement of equity for the quarter ended March 31, 2011 reflects the issuance of the EPB common units as an increase of $287 million to noncontrolling interests and $170 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 quarter ended March 31, 2011 totaled $232 million.

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. As the holder of these rights 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.

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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 ended March 31:

	$xxx,xxx,xx 2012	$xxx,xxx,xx 2011
	(In millions)	
EPB	$ 63	$ 52
Preferred Stock of Cheyenne Plains		5
Preferred Stock of Ruby		17
Net income attributable to noncontrolling interests	$ 63	$ 74

Convertible Perpetual Preferred Stock. In March 2011, we exercised our conversion right related to $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). For a further discussion of our convertible preferred stock, including authorized shares, see our 2011 Annual Report on Form 10-K.

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11. Business Segment Information

As of March 31, 2012, we have two core segments, Pipelines and Exploration and Production. We also have a Marketing segment. Our segments are strategic business units that provide a variety of energy products and services. They are managed separately as each segment requires different technology and marketing strategies. A further discussion of each segment and our other activities follows.

Pipelines. Our Pipelines segment provides natural gas transmission, storage, and related services in the United States. As of March 31, 2012, we conducted our activities primarily through eight wholly or majority 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 United States and internationally in Brazil.

Marketing. Our Marketing segment markets 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 midstream operations, corporate general and administrative functions, and miscellaneous businesses.

We use segment earnings before interest expense and income taxes (Segment EBIT) to measure and assess the operating results and effectiveness of our 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 and allows them to evaluate the performance of our operating businesses and investments without regard to the manner in which they are financed or our capital structure. Segment EBIT is defined as net income 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, income before income taxes and other performance measures such as operating income or operating cash flows.

Below is a reconciliation of our Segment EBIT to our net income for the periods ended March 31:

	2012	2011
	(In millions)	
Segment EBIT	$ 445	$ 395
Interest and debt expense	(226)	(240)
Income tax benefit (expense)	(70)	(19)
Net income	149	136
Net income attributable to noncontrolling interests	(63)	(74)
Net income attributable to El Paso Corporation	$ 86	$ 62

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

	Pipelines	Exploration and Production	Marketing	Other	Eliminations	Total
	Segments		(In millions)			
2012						
Revenue from external customers	$ 774	$ 371[(1)]	$ 113	$ 2	$	$ 1,260
Intersegment revenue[(2)]	15	113	(126)	1	(3)	
Operation and maintenance	196	106	2	34		338
Ceiling test charges		62				62
Depreciation, depletion and amortization	122	201		7		330
Earnings (losses) from unconsolidated affiliates	27	(3)		11		35
Segment EBIT	434	60	(15)	(30)	(4)	445
2011						
Revenue from external customers	$ 703	$ 84[(1)]	$ 201	$ 1	$	$ 989
Intersegment revenue[(2)]	50	166	(213)	1	(4)	
Operation and maintenance	190	101	2	13	(1)	305
Depreciation, depletion and amortization	114	134		6		254
Earnings (losses) from unconsolidated affiliates	25	(2)		7		30
Segment EBIT	499	(31)	(14)	(59)		395

(1) Revenues from external customers include gains of $76 million and losses of $109 million for the quarters ended March 31, 2012 and 2011 related to our financial derivative contracts associated with our oil and natural gas production.

(2) Our intersegment revenues, along with intersegment expenses, were incurred in the normal course of business between our operating segments. Intersegment revenues primarily represent sales to our Marketing segment, which is responsible for marketing our production to third parties.

Total assets by segment are presented below:

	March 31, 2012	December 31, 2011
	(In millions)	
Pipelines	$ 18,180	$ 18,282
Exploration and Production	5,131	4,946
Marketing	128	172
Other	919	893
Total segment assets	24,358	24,293
Eliminations	20	21
Total consolidated assets	$ 24,378	$ 24,314

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12. Accounts Receivable Sales Programs

Accounts Receivable Sales Program. We currently 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 existing programs are scheduled to terminate on May 29, 2012 however, we are evaluating options to extend the programs. 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 program.

	Quarter Ended March 31, 2012	Quarter Ended March 31, 2011
	(In millions)	
Accounts receivable sold to the third party financial institution[1]	$ 677	$ 607
Cash received for accounts receivable sold under the programs	365	353
Deferred purchase price related to accounts receivable sold	312	254
Cash received related to the deferred purchase price	337	248

(1) During the quarters ended March 31, 2012 and 2011, losses recognized on the sale of accounts receivable were immaterial.

	March 31, 2011	December 31, 2011
	(In millions)	
Accounts receivable sold and held by third party financial institution	$ 222	$ 254
Uncollected deferred purchase price related to accounts receivable sold [1]	105	130

(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 ended March 31, 2012 and 2011.

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13. 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 March 31, 2012 and December 31, 2011 and for the quarters ended March 31, 2012 and 2011:

	Investment		Earnings (Losses) from Unconsolidated Affiliates Quarter Ended March 31,	
	March 31, 2012	December 31, 2011	2012	2011
	(In millions)		(In millions)	
Net Investment and Earnings (Losses)				
Ruby [1]	$ 1,041	$ 1,066	$ 3	$
Citrus	933	916	17	25
Four Star [2]	329	340	(3)	(2)
Gulf LNG[3]	252	242	6	
Bolivia-to-Brazil Pipeline[4]	111	110	2	2
Other	76	65	10	5
Total	$ 2,742	$ 2,739	$ 35	$ 30

(1) We own all of the common interests of Ruby and our partner owns all of the convertible preferred interests in Ruby. We amortize a portion of the difference between our underlying equity in the net assets of Ruby and our investment balance. For the quarter ended March 31, 2012, these amounts totaled $6 million.

(2) We recorded amortization of 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 March 31, 2012 and 2011.

(3) As of March 31, 2012 and December 31, 2011, we had outstanding advances and receivables of $170 million and $165 million, included in other current and long term assets, related to our investment in Gulf LNG.

(4) We own 33 percent of BBPP Holdings Ltd., which owns 29 percent of the Bolivia to Brazil Pipeline.

Transactions with Unconsolidated Affiliates. We received distributions and dividends from our unconsolidated affiliates of approximately $33 million and $12 million for the quarters ended March 31, 2012 and 2011. Included in these amounts are returns of capital of $23 million and less than $1 million for the quarters ended March 31, 2012 and 2011. During the first quarter of 2012, we received $37 million from Citrus as repayment of their outstanding receivable balance related to a promissory note. Also during the quarter ended March 31, 2012, we transferred assets to our midstream joint venture which did not qualify as a sale due to our continuing involvement. As of March 31, 2012, the assets transferred totaled $89 million and amounts received were recorded as other long-term liabilities and included in financing activities on our statements of cash flows. Our other transactions with unconsolidated affiliates were not material during the quarters ended March 31, 2012 and 2011.

Summarized Financial Information of Unconsolidated Affiliates. Below is summarized financial information of the operating results of our unconsolidated affiliates.

	Quarter Ended March 31, 2012	2011
	(In millions)	
Summarized Financial Information		
Operating results data:		
Operating revenues	$ 423	$ 230
Operating expenses	219	140
Net income	104	90

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 $64 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 fully 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.

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Our project companies that previously owned the Manaus and Rio Negro power plants have also been assessed approximately $80 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. Any potential taxes owed by the Manaus and Rio Negro project companies are also guaranteed by the purchaser s parent. We do not believe that we will be required to pay any amounts related to this matter, and accordingly 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.

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 2011 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

Proposed Merger with Kinder Morgan, Inc. In October 2011, we entered into a definitive merger agreement (the merger agreement) with Kinder Morgan, Inc. (KMI) whereby KMI will acquire El Paso Corporation (El Paso) in a transaction that valued El Paso at approximately $38 billion (based on the KMI stock price at that date), including the assumption of debt. In March 2012, both our and KMI s stockholders approved the merger agreement and a series of transactions to effectuate the merger. As part of these transactions, on March 26, 2012, the common stockholders of El Paso Corporation (Old El Paso) became common stockholders of a new corporation (New El Paso); Old El Paso became a direct, wholly owned subsidiary of New El Paso; and New El Paso became the public reporting company as the successor issuer of Old El Paso (the predecessor for historical accounting purposes) for purposes of SEC filings. In conjunction with these transactions, Old El Paso was also converted into a Delaware limited liability company (renamed El Paso LLC) and New El Paso was renamed El Paso Corporation.

The merger agreement includes customary representations, warranties and covenants, and specific agreements relating to (i) the conduct of each of El Paso s and KMI s respective businesses between the date of the signing of the merger agreement and the closing of the merger transactions and (ii) the efforts of the parties to cause the merger transactions to be completed. In addition to certain other covenants, we have agreed not to encourage, solicit, initiate or facilitate any takeover proposal from a third party or enter into any agreement, arrangement or understanding requiring us to abandon, terminate or fail to consummate the merger and related transactions. The merger agreement contains certain termination rights for both El Paso and KMI.

Under the terms of the merger agreement, we have agreed to conduct our business in the ordinary course and in all material respects in substantially the same manner as conducted prior to the date of the merger agreement, subject to certain conditions, restrictions and thresholds including, but not limited to, our ability to (i) commit to capital expenditures above our current capital budgets (ii) acquire, invest in, or dispose of any material properties, assets, or equity interests as defined in the merger agreement (iii) incur new debt, refinance, or guarantee any debt or borrowed money, (iv) enter into, terminate, or amend certain material contracts, (v) issue, grant, sell, or redeem new El Paso capital stock or stock-based compensation awards and/or pay dividends in excess of $0.01/share, among other limitations.

In conjunction with the merger agreement, KMI announced that they intend to sell our exploration and production assets. On February 24, 2012, we entered into a purchase and sale agreement to sell all of our exploration and production assets to an affiliate of Apollo Global Management, LLC (Apollo) and certain other parties for $7.15 billion subject to certain adjustments for items such as contributions or distributions, incurrence of debt and title defects. The closing of the sale of these assets is conditioned upon completion of the merger transactions with KMI. The purchase and sale agreement contains customary representations and warranties relating to the exploration and production assets and operations. Additionally, El Paso has entered into a performance guarantee in favor of Apollo, under which we guarantee the performance of all of our seller subsidiaries obligations under the purchase and sale agreement. Pursuant to the merger agreement with KMI, KMI is required to indemnify us from any and all cost incurred by us arising from or relating to the sale of the exploration and production assets. Upon completion of the sale to Apollo, the exploration and production business will be reflected as a discontinued operation in our financial statements.

In April 2012, we proposed an offer for EPB (a consolidated subsidiary) to purchase the remaining 14 percent interest in CIG and a 100 percent interest in Cheyenne Plains Investment Company, L.L.C., which owns Cheyenne Plains Gas Pipeline Company, L.L.C. The proposal is subject to approval by EPB s Board of Directors. If approved, the transaction is expected to close contemporaneously with KMI s acquisition of El Paso. Also, in April 2012, KMI announced, subject to the completion of the merger with El Paso, that it expects to drop down all of our interests in TGP and a portion of our interest in EPNG to Kinder Morgan Energy Partners, L.P., a consolidated subsidiary of KMI, during the third quarter of 2012.

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On May 1, 2012, KMI announced that it received approval from the Federal Trade Commission (FTC) for the merger, subject to the previously announced divestiture of certain assets. We expect remaining required regulatory approvals, shareholder consideration elections and other remaining transactions contemplated in conjunction with the KMI merger, including the sale of our exploration and production assets, to be completed by the end of May 2012.

For a further discussion of the merger and related transactions, see Item 1. Financial Statements, Note 1.

Summary of Quarterly Performance

For the quarter ended March 31, 2012, our Segment EBIT was $445 million, compared with $395 million for the first quarter of 2011. Pipelines Segment EBIT decreased during the quarter by approximately $65 million largely due to recording lower allowance for funds used during construction (AFUDC) primarily related to our Ruby pipeline project completed in 2011. During the same period, we benefited from pipeline expansion projects placed in service in 2011 and new rates on our TGP pipeline system. In the Exploration and Production segment, Segment EBIT increased by $91 million over first quarter of 2011, primarily due to changes in the mark-to-market impacts of financial derivatives, increases in oil, NGL and natural gas production volumes and higher oil prices, partially offset by lower natural gas and NGL prices and higher depreciation, depletion and amortization expense versus last year. Our operating and financial results are further discussed in the individual segment results that follow.

As to liquidity, we ended the quarter with $1.0 billion of available liquidity (exclusive of EPB s cash and credit facility capacity). Our capital requirements and debt maturities are expected to be funded through this available liquidity and operating cash flows. Further discussion is in the section entitled *Liquidity and Capital Resources.*

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Segment Results

As of March 31, 2012, we have 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.

We use segment earnings before interest expense and income taxes (Segment EBIT) to measure and assess the operating results and effectiveness of our 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 and allows them 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 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, income before income taxes and other performance measures such as operating income or operating cash flows.

Below is a reconciliation of our Segment EBIT to our consolidated net income for the quarters ended March 31:

	2012	2011
	(In millions)	
Segment		
Pipelines	$ 434	$ 499
Exploration and Production	60	(31)
Marketing	(15)	(14)
Other	(30)	(59)
Eliminations	(4)	
Segment EBIT	445	395
Interest and debt expense	(226)	(240)
Income tax expense	(70)	(19)
Net income	149	136
Net income attributable to noncontrolling interests	(63)	(74)
Net income attributable to El Paso Corporation	$ 86	$ 62

Pipelines Segment

Overview and Operating Results. Our Pipelines Segment EBIT for the quarter ended March 31, 2012 was lower than the same period of 2011 by $65 million. Although we benefited from pipeline expansion projects placed in service in 2011 and new rates on our TGP pipeline system, Pipelines Segment EBIT decreased largely due to recording lower AFUDC in 2012 primarily related to our Ruby pipeline project and lower revenues on TGP s retained fuel in excess of fuel used in operations. Below are the operating results for our Pipelines segment as well as a discussion of factors impacting Segment EBIT for the quarters ended March 31, 2012 compared with 2011.

	2012	2011
	(In millions, except for volumes)	
Operating revenues	$ 789	$ 753
Operating expenses	(392)	(378)
Operating income	397	375
Other income, net	37	124
Segment EBIT	$ 434	$ 499
Throughput volumes (BBtu/d)[1]	19,864	18,038

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

	Variance			
	Operating Revenue	Operating Expense	Other	Total
	Favorable/(Unfavorable) (In millions)			
Expansions	$ 34	$ (3)	$ (86)	$ (55)
Reservation/usage revenues and expenses	48	(2)		46
Gas not used in operations and revaluations	(45)	2		(43)
Operating and general and administrative expense		(8)		(8)
Other[1]	(1)	(3)	(1)	(5)
Total impact on Segment EBIT	$ 36	$ (14)	$ (87)	$ (65)

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

Expansions. During 2012, we benefited from increased reservation revenues from expansion projects placed in service in 2011, including Phase II of the SNG South System III Expansion and the TGP 300 Line expansion project. Partially offsetting these increases were depreciation and other operating expenses associated with placing these projects in service.

We capitalize a carrying cost (AFUDC) on funds related to our construction of long-lived assets. During the quarter ended March 31, 2012, our Segment EBIT was impacted by a decline of approximately $86 million when compared with the same period in 2011 associated with the equity portion of AFUDC primarily on our Ruby pipeline project (prior to deconsolidation).

Reservation/Usage Revenue and Expenses. Overall, reservation and usage revenues increased for the quarter ended March 31, 2012 compared to the same period in 2011 as discussed below:

TGP. Our TGP system experienced an overall net increase in reservation and usage revenues of approximately $50 million for the quarter ended March 31, 2012 compared to the same period in 2011. The increase was primarily due to higher rates effective June 1, 2011 as a result of TGP s rate case and higher throughput volumes due to increased supply from the Eagle Ford, Haynesville and Marcellus shale basins**.** Partially offsetting these favorable impacts were lower usage revenues on certain interruptible services due to lower basis differentials.

EPNG. Effective April 1, 2011, EPNG s rates, which are subject to refund, increased pursuant to its 2010 rate case resulting in an increase in reservation revenues. Partially offsetting these amounts was slightly lower throughput on our EPNG system due to increased competition in the California market. The overall favorable impact of these items for the quarter ended March 31, 2012 compared to 2011 was approximately $7 million.

CIG/SNG. For the quarter ended March 31, 2012, we experienced lower reservation revenues on our CIG and SNG systems of $7 million and $2 million, respectively. Certain contracts on our CIG system were renewed at lower volumes or discounted rates. On our SNG system, changes in certain customers contracting strategies resulted in the nonrenewal of expiring contracts.

Gas Not Used in Operations and Revaluations. Effective June 1, 2011, TGP implemented a fuel volume tracker as part of its rate case and as a result, no longer recognizes revenues associated with gas not used in operations. Implementing the fuel volume tracker lowered our Segment EBIT by $38 million for the quarter ended March 31, 2012 compared to the same period in 2011. In addition, TGP implemented an electric compression tracker as part of its rate case which resulted in lower electric compression expenses of $5 million. The net unfavorable impact associated with implementing these trackers is offset by higher rates under its rate case resulting in higher reservation revenues discussed above. During March 2011, we also recognized revenues of $8 million related to other natural gas sales.

Operating and General and Administrative Expenses. During the quarter ended March 31, 2012, the Pipelines Segment experienced higher allocated overhead costs based on the estimated level of resources devoted to the segment and other factors which unfavorably impacted segment results by $8 million when compared to the same period in 2011.

Other Regulatory Matters

Rate Cases. 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 discussed 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 and concluded in December 2011. A decision is due in May 2012. 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 the 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 December 2011, the FERC approved TGP s settlement that resolved the outstanding issues arising from its general rate case filing. As part of the settlement, TGP refunded approximately $69 million, including interest, to its customers in March 2012. For a further discussion of TGP s rate case settlement, see our 2011 Annual Report on Form 10-K.

Assets Sale. In November 2011, the FERC issued an order approving, in part, and rejecting certain portions of our abandonment application related to our October 2010 agreement to sell certain of our offshore pipeline assets and related facilities. The sale was contingent upon receiving approval to collect in our future rates the difference between the regulatory net book value and the purchase price (loss) and the designation of certain facilities as non-jurisdictional. In December 2011, we filed a request for partial rehearing and stay of the November order, which was denied by the FERC in March 2012. In April 2012, we entered into an amended and restated purchase and sale agreement which includes additional facilities in exchange for an increase in the purchase price, as well as an updated schedule for obtaining regulatory approvals prior to closing. We anticipate filing a new abandonment application with the FERC by mid-2012 and as a condition of the sale, we intend to recover a regulatory asset for portion of the loss on sale. In addition, if satisfactory regulatory approvals are received, we would record a non-cash loss for the portion of the loss that we cannot recover as a regulatory asset. However, the outcome of the FERC s approval of the application, including our ability to recover the regulatory asset in future rates, is currently undeterminable.

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Exploration and Production Segment

Overview and Strategy

Our exploration and production business is focused on finding, developing and producing oil, natural gas and NGL, primarily in North America. The profitability and performance of our business is driven by an ability to find and develop economic oil and natural gas reserves and extract those reserves at the lowest possible production and administrative costs. Our strategy focuses on building and applying competencies in assets with repeatable programs, maximizing returns by adding assets, reserves and resources that match our competencies and divesting assets that do not and by executing to improve capital expense efficiency. In 2012, as a result of executing our strategy, we increased oil, natural gas and NGL production volumes, lowered per unit cash operating costs, and expanded a hedging program designed to support the balance sheet and cash flows. The 2012 exploration and production capital program is focused on oil opportunities, particularly in the Altamont, Eagle Ford, South Louisiana Wilcox and Wolfcamp areas. For a further discussion of our business strategy and asset base in our exploration and production business, see our 2011 Annual Report on Form 10-K.

Our exploration and production operations generate profits dependent on the prices for oil and natural gas, the costs to explore, develop, and produce oil and natural gas, and the volumes we are able to produce, among other factors. Our long-term profitability will be primarily influenced by the following factors:

- Growing our oil and natural gas proved reserve base and production volumes through successful execution of our drilling programs;
- Finding and producing oil and natural gas at a reasonable cost; and
- Managing price risks to optimize realized prices on our oil and natural gas production.

In addition to these factors, our profitability and performance is impacted by the effects of volatility in the financial and commodity markets, industry-wide changes in the cost of drilling and oilfield services which impact our daily production, operating and capital costs, our debt level and related interest costs. We may also be impacted by the effect of hurricanes and other weather events, domestic or international regulatory issues or other actions 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 longer term contractual arrangements to control costs and entering into derivative contracts to reduce the financial impact of downward commodity price movements.

Significant Operational Factors Affecting the Periods Ended March 31, 2012 and 2011

Production. Our average daily production for the three months ended March 31, 2012 was 908 MMcfe/d, including 57 MMcfe/d from our equity interest in the production of Four Star. Below is an analysis of our production by division for the quarters ended March 31:

	2012	**2011**
	MMcfe/d	
United States		
Central	451	406
Western	155	155
Southern	209	166
International		
Brazil	36	31
Total Consolidated	851	758
Unconsolidated affiliate	57	63
Total Combined	908	821

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Volumes. Our production volumes by commodity for the three months ended March 31 were as follows:

	2012	2011
Natural Gas (MMcf/d)		
Consolidated volumes	688	659
Unconsolidated affiliate volumes	43	47
Total Combined	731	706
Oil and condensate (MBbls/d)		
Consolidated volumes	22	13
Unconsolidated affiliate volumes	1	1
Total Combined	23	14
NGL (MBbls/d)		
Consolidated volumes	5	3
Unconsolidated affiliate volumes	1	2
Total Combined	6	5

Central division Our 2012 Central division production volumes increased primarily as a result of our drilling program in the Haynesville Shale. At March 31, 2012, we had 64 net operated wells and our total production was approximately 314 MMcfe/d. Although we have a very efficient program in the Haynesville Shale, we suspended the program at the end of the first quarter of 2012 due to low natural gas prices. We have released all rigs and plan to redeploy the capital allocated to the Haynesville Shale to our oil programs. In addition, a relatively new oil play, the South Louisiana Wilcox program had 16 net operated wells with total oil and NGL production of approximately 2 MBbls/d.

Western division Our 2012 Western division production volumes were steady when compared to prior year, despite divestitures in our Rockies area, primarily due to our successful drilling programs in our Altamont and Raton Basin areas. During the quarter ended March 31, 2012, we have drilled four additional net wells in our Altamont Field, for a total of 288 net operated wells.

Southern division Our 2012 Southern division production volumes increased primarily due to our successful drilling programs in the Eagle Ford and Wolfcamp shales, offset by natural declines and lower levels of drilling activity in the Texas Gulf Coast and Gulf of Mexico areas. During the quarter ended March 31, 2012, we drilled 15 additional wells in our Eagle Ford Shale for a total of 79 net operated wells. With a majority of our acreage located in the oil and liquids rich area of the Eagle Ford Shale, our total oil and NGL production was approximately 11 MBbls/d for the quarter ended March 31, 2012, an increase of over 350 percent from the same period of last year. In our Wolfcamp Shale area, we drilled 6 additional wells during 2012, for a total of 20 net operated wells.

International Our first quarter 2012 production in Brazil increased to 36 MMcfe/d primarily due to a fourth well coming on line in August 2011 and an oil offloading in March 2012 from our Camarupim Field. We are still awaiting a response on our appeal filed in 2011, for our environmental permit request concerning the Pinauna Field which was denied by the Brazilian environmental regulatory agency. On April 30, 2012, we entered into a purchase and sale agreement to sell all our interests in Egypt. The sale will represent an exit from our Egyptian exploration activities.

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. During the quarter ended March 31, 2012, cash operating costs per unit decreased to $1.74/Mcfe as compared to $1.85/Mcfe during the same period in 2011, primarily due to higher production volumes and lower general and administrative costs, offset by higher lease operating expenses.

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The table below represents a reconciliation of our cash operating costs for the quarters ended March 31:

	Quarter Ended March 31, 2012 Total	2012 Per unit	2011 Total	2011 Per unit
	(In millions, except per unit costs)			
Total operating expenses	$ 422	$ 5.45	$ 280	$ 4.11
Depreciation, depletion and amortization	(201)	(2.59)	(134)	(1.96)
Transportation costs	(25)	(0.32)	(20)	(0.30)
Ceiling test charges	(62)	(0.80)		
Total cash operating costs and per-unit cash costs[(1)]	$ 134	$ 1.74	$ 126	$ 1.85
Total equivalent volumes (MMcfe)[(1)]	77,465		68,187	

(1) Excludes volumes and costs associated with Four Star.

Capital Expenditures. Our total oil and natural gas capital expenditures were $381 million for the quarter ended March 31, 2012, of which $379 million were domestic capital expenditures. Capital expenditures for the quarter ended March 31, 2012 and rig count by core program as of March 31, 2012 were:

	Capital Expenditures (In millions)	Rig Count
Eagle Ford	$ 203	4
Haynesville	60	
Altamont	34	2
Wolfcamp	47	1
South Louisiana Wilcox	34	1
Other, including International	3	
Total capital expenditures	$ 381	8

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 quarter of 2012, approximately 40 percent of our natural gas production and 80 percent of our crude oil production were hedged and settled at average floor prices of $5.96 per MMBtu and $93.30 per barrel, respectively.

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The following table reflects the contracted volumes and the minimum, maximum and average prices we will receive under our derivative contracts as of March 31, 2012.

	2012		2013		2014		2015	
	Volumes[(1)]	Average Price[(1)]	Volumes[(1)]	Average Price[(1)]	Volumes[(1)]	Average Price[(1)]	Volumes[(1)]	Average Price[(1)]
Natural Gas								
Fixed Price Swaps	155	$ 4.47	79	$ 3.58	52	$ 3.92		$
Oil								
Fixed Price Swaps	1,372	$ 105.72	7,430	$ 104.83	8,760	$ 98.64	6,205	$ 95.49
Ceilings	1,100	$ 95.00	2,920	$ 96.88	1,095	$ 100.00	1,095	$ 100.00
Three Way Collars Ceilings	4,330	$ 114.16	1,552	$ 128.34		$		$
Floors [(2)]	4,330	$ 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) If market prices settle at or below $67.54 and $75.00 for the years 2012 and 2013, respectively, our three-way collars-floors effectively lock-in a cash settlement of the market price plus $25.00 per Bbl for 2012 and 2013.

During April of 2012, we entered into additional fixed price swaps on 22 TBtu at an average price of $3.38 per MMBtu for our 2013 anticipated natural gas production, 980 MBbls at an average price of $104.37 per barrel for our remaining 2012 anticipated oil production and 548 MBbls at an average price of $96.60 per barrel for our 2015 anticipated oil production.

Operating Results and Variance Analysis

The information below provides the financial results and an analysis of significant variances in these results during the quarters ended March 31:

	Quarter Ended March 31,	
	2012	2011
	(In millions)	
Physical sales		
Natural gas	$ 182	$ 240
Oil and condensate	209	103
NGL	17	15
Total physical sales	408	358
Realized and unrealized gains (losses) on financial derivatives	76	(109)
Other revenues		1
Total operating revenues	484	250
Operating expenses		
Transportation costs	25	20
Production costs	87	73
Depreciation, depletion and amortization	201	134
General and administrative expenses	44	50
Ceiling test charges	62	
Other	3	3

Total operating expenses	422	280
Operating income (loss)	62	(30)
Other income (expense) [1]	(2)	(1)
Segment EBIT	$ 60	$ (31)

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

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

	Quarter Ended March 31, 2012	2011
Volumes		
Natural gas (MMcf)		
Consolidated volumes	62,629	59,262
Unconsolidated affiliate volumes	3,947	4,253
Oil and condensate (MBbls)		
Consolidated volumes	2,052	1,194
Unconsolidated affiliate volumes	77	82
NGL (MBbls)		
Consolidated volumes	420	293
Unconsolidated affiliate volumes	123	152
Equivalent volumes		
Consolidated (MMcfe)	77,465	68,187
Unconsolidated affiliate (MMcfe)	5,147	5,660
Total combined (MMcfe)	82,612	73,847
Consolidated (MMcfe/d)	851	758
Unconsolidated affiliate (MMcfe/d)	57	63
Total combined (MMcfe/d)	908	821
Consolidated prices and costs per unit		
Natural gas		
Average realized price on physical sales ($/Mcf)	$ 2.90	$ 4.06
Average realized price, including financial derivative settlements ($/Mcf) [(1)(2)]	$ 4.27	$ 5.44
Average transportation costs ($/Mcf)	$ 0.33	$ 0.31
Oil and condensate		
Average realized price on physical sales ($/Bbl)	$ 101.81	$ 86.27
Average realized price, including financial derivative settlements ($/Bbl) [(1)(2)]	$ 100.16	$ 85.69
Average transportation costs ($/Bbl)	$ 1.11	$ 0.06
NGL		
Average realized price on physical sales ($/Bbl)	$ 40.96	$ 50.37
Average transportation costs ($/Bbl)	$ 5.47	$ 5.01
Cash operating costs		
Average lease operating expenses ($/Mcfe)	$ 0.81	$ 0.74
Average production taxes ($/Mcfe) [(3)]	0.32	0.32
Average general and administrative expenses	0.57	0.74
Average taxes, other than production and income taxes	0.04	0.05
Total cash operating costs	$ 1.74	$ 1.85
Depreciation, depletion and amortization ($/Mcfe)[(4)]	$ 2.59	$ 1.96

(1)

We had no cash premiums related to natural gas and oil derivatives settled during the quarter ended March 31, 2012. Premiums related to natural gas derivatives settled during the quarter ended March 31, 2011 were approximately $6 million. Had we included these premiums in our natural gas average realized prices in 2011, our realized price, including financial derivative settlements, would have decreased by $0.10/Mcf for the quarter ended March 31, 2011. We had no cash premiums related to oil derivatives settled during the quarter ended March 31, 2011.

(2) The quarters ended March 31, 2012 and 2011 include approximately $86 million and $82 million, respectively, of cash receipts on settlements related to natural gas derivative contracts and approximately $(4) million and $(1) million of cash paid on settlements related to crude oil derivative contracts.

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

(4) Includes $0.04 per Mcfe and $0.06 per Mcfe for the quarters ended March 31, 2012 and 2011 related to accretion expense on asset retirement obligations.

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Quarter Ended March 31, 2012 Compared with Quarter Ended March 31, 2011

Our Segment EBIT for the quarter ended March 31, 2012 increased $91 million as compared to the same period in 2011. The table below shows the significant variances of our financial results for the quarter ended March 31, 2012 as compared with the same period in 2011:

	Variance			
	Operating Revenue	Operating Expense	Other	Segment EBIT
	Favorable/(Unfavorable) (In millions)			
Physical sales				
Natural gas				
Lower realized prices in 2012	$ (72)	$	$	$ (72)
Higher volumes in 2012	14			14
Oil and condensate				
Higher realized prices in 2012	32			32
Higher volumes in 2012	74			74
NGL				
Lower realized prices in 2012	(4)			(4)
Higher volumes in 2012	6			6
Realized and unrealized gains on financial derivatives	185			185
Other revenues	(1)			(1)
Depreciation, depletion and amortization expense				
Higher depletion rate in 2012		(50)		(50)
Higher production volumes in 2012		(17)		(17)
Transportation costs		(5)		(5)
Production costs				
Higher lease operating expenses in 2012		(11)		(11)
Higher production taxes in 2012		(3)		(3)
General and administrative expenses		6		6
Ceiling test charges		(62)		(62)
Losses from investment in Four Star			(1)	(1)
Total Variances	$ 234	$ (142)	$ (1)	$ 91

Physical sales. Physical sales represent accrual-based commodity sales transactions with customers. For the quarter ended March 31, 2012, physical sales were $408 million compared to $358 million for the quarter ended March 31, 2011. The overall increase of $50 million, or 14 percent, was a result of the (i) favorable impact of $74 million, $14 million and $6 million related to higher production volumes of oil and condensate, natural gas and NGL, respectively, (ii) a favorable impact of $32 million related to the increase in realized oil and condensate prices and (iii) the unfavorable impact of $72 million and $4 million related to lower realized prices for natural gas and NGL, respectively. The increase in oil and NGL production is primarily attributable to our Eagle Ford program which is up 9 MBbls/d year over year.

Realized and unrealized gains on financial derivatives. Realized and unrealized gains for the first quarter of 2012 were $76 million compared to $109 million realized and unrealized losses for the first quarter of 2011. The increase of $185 million was 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. Depreciation, depletion and amortization expense for the quarter ended March 31, 2012 was $201 million compared to $134 million for the quarter ended March 31, 2011. The increase of $67 million, or 50 percent, was a result of an increase of $50 million due to a higher depletion rate and an increase of $17 million due to higher production volumes compared to the same period in 2011. As expected, the upward trend in our depletion rate relative to prior periods has continued as we focus our capital expenditures on developing our core oil programs.

Transportation costs. Transportation costs for the quarter ending March 31, 2012 were $25 million compared to $20 million for the first quarter of 2011. This increase of $5 million, or 25 percent, was due primarily to new transportation contracts entered into in 2012.

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Production costs. Production costs for the quarter ending March 31, 2012 were $87 million compared to $73 million for the first quarter of 2011. This increase of $14 million, or 19 percent, was due primarily to an increase of $11 million in lease operating expenses and an increase of $3 million in production taxes. Lease operating expenses are attributable to increased water disposal costs in our Southern and Central divisions and higher equipment and maintenance costs in our Southern division. Production taxes increased primarily due to higher production volumes.

General and administrative expenses. General and administrative expenses for the first quarter of 2012 were $44 million compared to $50 million for the first quarter of 2011. The decrease of $6 million, or 12 percent, is primarily due to a one-time severance cost of approximately $5 million paid in 2011 related to an office closure.

Ceiling test charges. Each quarter, we are required to evaluate our capitalized costs in each of our full cost pools. During the quarter ended March 31, 2012 we recorded a non-cash charge of approximately $62 million as a result of our decision to no longer explore or develop our acreage in Egypt. On April 30, 2012, we entered into a purchase and sale agreement to sell all our interests in Egypt. The sale will represent an exit from our Egyptian exploration activities. We may incur 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.

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, including legacy contracts which were primarily entered into prior to the deterioration of the energy trading environment in 2002. This segment also has agreements with our midstream joint venture to market the natural gas and natural gas liquids production from its Utah operations. All of our contracts are subject to counterparty credit and non-performance risks while our remaining mark-to-market contracts are also subject to interest rate exposure. Revenues of our Marketing activities are recorded net of related costs. Our contracts are described below and in further detail in our 2011 Annual Report on Form 10-K.

Natural gas transportation-related contracts. The impact of these accrual-based transportation 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 March 31, 2012, these contracts require us to pay demand charges of $34 million for the remainder of 2012 and an average of $23 million per year between 2013 and 2016.

Legacy natural gas and power contracts. As of March 31, 2012, 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 earnings impact to us 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 ended March 31 are as follows:

	2012	2011
	(In millions)	
Income (Loss):		
Accrual-based contracts (including natural gas transportation):		
Demand charges	$ (12)	$ (10)
Settlements, net of termination payments	2	(1)
Changes in fair value of other natural gas derivative contracts	(1)	
Changes in fair value of power contracts	(2)	(1)
Total revenues	(13)	(12)
Operating expenses	(2)	(2)
Operating income (loss)	$ (15)	$ (14)
Other income, net		

Segment EBIT	$ (15)	$ (14)

Our first quarter 2012 results were primarily driven by increased demand charges due to an increase in transportation tariff rates on existing contracts and changes in natural gas prices. Our first quarter 2011 results include a $15 million loss related to settlements on an affiliated fuel supply agreement.

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Other Activities

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

The following is a summary of significant items impacting the Segment EBIT in our other activities for the quarters ended March 31:

Income (Loss)	2012	2011
	(In millions)	
Loss on debt extinguishment	$	$ (41)
Change in environmental, legal, and other reserves	(16)	(11)
Midstream	8	2
Net earnings related to legacy investments	4	6
Merger-related costs	(12)	
Other	(14)	(15)
Total Segment EBIT	$ (30)	$ (59)

Loss on Debt Extinguishment. During the first quarter of 2011, we recorded losses in conjunction with repurchasing $148 million 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 were primarily impacted by adjustments to certain legacy environmental matters, including non-operated refineries in Kansas and Texas in 2012 and a non-operated chemical plant in 2012 and 2011. Also impacting these results were market adjustments to an indemnification agreement on which our liability fluctuates with ammonia prices.

Net Earnings Related to Legacy Investments. During the quarters ended March 31, 2012 and 2011, we recorded equity earnings related to our legacy investments. Historically these investments have included legacy foreign power, telecommunications and other operations, certain of which are impacted by foreign currency fluctuations.

Merger-Related Costs. During 2012, we incurred $12 million of costs associated with our anticipated merger with Kinder Morgan.

Other. Our results are impacted by other items including benefit costs associated with certain of our post-retirement and other benefit plans, none of which are individually significant.

Interest and Debt Expense

Our interest and debt expense decreased during the quarter ended March 31, 2012 as compared to the same period in 2011 primarily due to the 2011 repurchase of approximately $1.0 billion of debt having interest rates ranging from 6.875 percent to 12 percent. Interest savings associated with these liability management transactions have been partially offset by interest costs on new borrowings.

Income Taxes

	Quarter Ended March 31,	
	2012	2011
	(In millions, except for rates)	
Income taxes	$ 70	$ 19
Effective tax rate	32%	12%

During the first quarter of 2012, our effective tax rate was lower than the statutory rate primarily due to income attributable to nontaxable noncontrolling interests and dividend exclusions on earnings from unconsolidated affiliates where we anticipate receiving dividends. Partially offsetting these items was the impact of an Egyptian ceiling test charge without a corresponding tax benefit. A tax benefit of approximately $40 million associated with the anticipated capital loss on the sale of our interests in Egypt will be recorded in the second quarter of 2012 consistent with the timing of our board s approval of the transaction. For a discussion of our ceiling test charges, see Item 1, Financial Statements, Note 2.

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For the first quarter of 2011, our effective tax rate was lower than the statutory rate due to income attributable to nontaxable noncontrolling interests, dividend exclusions on earnings from unconsolidated affiliates where we anticipate receiving dividends, the resolution of several tax matters and earned state tax credits.

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

Commitments and Contingencies

For a further discussion of our commitments and contingencies, see Item 1, Financial Statements, Note 8, which is incorporated herein by reference and our 2011 Annual Report on Form 10-K.

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Liquidity and Capital Resources

As of March 31, 2012, we had approximately $1.0 billion of available liquidity (exclusive of EPB s cash and credit facility capacity). Pursuant to the merger agreement with KMI, we are subject to certain conditions, restrictions and thresholds, including our ability to refinance or incur new debt, issue El Paso capital stock and/or dispose of any material properties, assets or equity interests other than as prescribed in the merger agreement. However, as a result of our current available liquidity and hedging program we have in place on our oil and natural gas production, we expect our current liquidity sources and operating cash flow to be sufficient to fund our working capital requirements, estimated 2012 capital expenditures and approximately $356 million of remaining 2012 debt maturities. We will assess and take actions where prudent and in the ordinary course of business 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, but not limited to, completion of our proposed merger with KMI or a further decline in commodity prices. If these events occur, or fail to occur, additional adjustments to our plan 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. For a further discussion of our liquidity and capital resources, see our 2011 Annual Report on Form 10-K.

Overview of Cash Flow Activities. During the first quarter of 2012, we generated operating cash flow of $0.5 billion primarily from our pipeline and exploration and production operations and borrowed $0.5 billion under our revolving credit facilities. We used cash flow generated from these operating and financing activities to fund our pipeline and exploration and production capital programs and to make net repayments under our various credit facilities and other debt obligations, among other items. For the quarter ended March 31, 2012, our cash flows are summarized as follows:

	2012 (In billions)
Cash Flow from Operations	
Operating activities	
Net income	$ 0.1
Other income adjustments	0.5
Change in assets and liabilities	(0.1)
Total cash flow from operations	$ 0.5
Other Cash Inflows	
Financing activities	
Net proceeds from the issuance of long-term debt	$ 0.5
Other	0.1
Total other cash inflows	$ 0.6
Cash Outflows	
Investing activities	
Capital expenditures	$ 0.5
Financing activities	
Payments to retire long-term debt and other financing obligations	0.5
Total cash outflows	$ 1.0
Net change in cash	$ 0.1

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

This information updates, and should be read in conjunction with the information disclosed in our 2011 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 2011 Annual Report on Form 10-K, except as presented below:

Commodity Price Risk

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

		Change in Market Price			
		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
			(In millions)		
Production-related derivatives net assets (liabilities)					
March 31, 2012	$ 198	$ (195)	$ (393)	$ 580	$ 382
December 31, 2011	$ 201	$ 88	$ (113)	$ 303	$ 102
Other commodity-based derivatives net assets (liabilities)					
March 31, 2012	$ (280)	$ (279)	$ 1	$ (281)	$ (1)
December 31, 2011	$ (311)	$ (309)	$ 2	$ (312)	$ (1)

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Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of March 31, 2012, 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 March 31, 2012.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the first quarter of 2012 that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

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PART II OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Financial Statements, Note 8, which is incorporated herein by reference. Additional information about our legal proceedings can be found in Part I, Item 3 of our 2011 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;

goals and objectives for future operations; and 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 2011 Annual Report on Form 10-K under Part I, Item 1A, Risk Factors. There have been no material changes in our risk factors since that report.

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

None.

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Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

Item 6. Exhibits

The Exhibit Index is incorporated herein by reference.

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

- should not in all instances be treated as categorical statements of fact, but rather as a way of allocating the risk to one of the parties if those statements prove to be inaccurate;
- may have been qualified by disclosures that were made to the other party in connection with the negotiation of the applicable agreement, which disclosures are not necessarily reflected in the agreement;
- may apply standards of materiality in a way that is different from what may be viewed as material to certain investors; and
- were made only as of the date of the applicable agreement or such other date or dates as may be specified in the agreement and are subject to more recent developments.

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

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SIGNATURES

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

EL PASO CORPORATION

Date: May 4, 2012

/s/ John R. Sult
John R. Sult
Executive Vice President and Chief Financial Officer

(Principal Financial Officer)

Date: May 4, 2012

/s/ Francis C. Olmsted III
Francis C. Olmsted III
Vice President and Controller

(Principal Accounting Officer)

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EL PASO CORPORATION

EXHIBIT INDEX

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

Exhibit Number	Description
*10.1#	Purchase and Sale Agreement, dated as of February 24, 2012, by and among, EP Energy Corporation, EP Energy Holding Company, El Paso Brazil, L.L.C., EPE Acquisition, LLC and solely for the obligations in Section 9.2(c) and Article XI and for no other purpose, Kinder Morgan, Inc.
*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.

Pursuant to Item 601(b)(2) of Regulation S-K, the registrant agrees to furnish supplementally a copy of any omitted exhibit or schedule to the Securities and Exchange Commission upon request.