UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

F O R M 10-Q

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2013

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: 1-11234

KINDER MORGAN ENERGY PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**76-0380342**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*

1001 Louisiana Street, Suite 1000, Houston, Texas 77002
(Address of principal executive offices)(zip code)
Registrant's telephone number, including area code: 713-369-9000

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 Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) 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]

The Registrant had 258,605,877 common units outstanding as of April 29, 2013.

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements.

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(In Millions Except Per Unit Amounts)
(Unaudited)

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
Revenues		
Natural gas sales	$ 735	$ 584
Services	1,188	761
Product sales and other	738	503
Total Revenues	2,661	1,848
Operating Costs, Expenses and Other		
Costs of sales	957	580
Operations and maintenance	384	306
Depreciation, depletion and amortization	328	239
General and administrative	134	107
Taxes, other than income taxes	74	50
Total Operating Costs, Expenses and Other	1,877	1,282
Operating Income	784	566
Other Income (Expense)		
Earnings from equity investments	83	65
Amortization of excess cost of equity investments	(2)	(2)
Interest expense, net	(199)	(135)
Gain on sale of investments in Express pipeline system	225	—
Other, net	4	1
Total Other Income (Expense)	111	(71)
Income from Continuing Operations Before Income Taxes	895	495
Income Tax Expense	(101)	(15)
Income from Continuing Operations	794	480
Discontinued Operations (Notes 1 and 2)		
Income from operations of FTC Natural Gas Pipelines disposal group	—	50
Loss on sale and the remeasurement of FTC Natural Gas Pipelines disposal group to fair value	(2)	(322)
Loss from Discontinued Operations	(2)	(272)
Net Income	792	208
Net Income Attributable to Noncontrolling Interests	(9)	(2)
Net Income Attributable to Kinder Morgan Energy Partners, L.P.	$ 783	$ 206
Calculation of Limited Partners' Interest in Net (Loss) Income Attributable to Kinder Morgan Energy Partners, L.P.:		
Income from Continuing Operations	$ 785	$ 475
Less: Pre-acquisition income from operations of drop-down asset group allocated to General Partner	(19)	—
Add: Drop-Down asset group severance expense allocated to General Partner	2	—
Less: General Partner's remaining interest	(402)	(321)
Limited Partners' Interest	366	154
Add: Limited Partners' interest in discontinued operations	(2)	(266)
Limited Partners' Interest in Net Income (Loss)	$ 364	$ (112)
Limited Partners' Net Income (Loss) per Unit - basic and diluted:		
Income from Continuing Operations	$ 0.97	$ 0.46
Loss from Discontinued Operations	—	(0.79)
Net Income (Loss) - basic and diluted	$ 0.97	$ (0.33)
Weighted Average Number of Units Used in Computation of Limited Partners' Net Income per Unit	376	338
Per Unit Cash Distribution Declared	$ 1.30	$ 1.20

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In Millions)
(Unaudited)

	Three Months Ended March 31,	
	2013	**2012**
Net Income	$ 792	$ 208
Other Comprehensive Income (Loss):		
Change in fair value of derivatives utilized for hedging purposes	(41)	(114)
Reclassification of change in fair value of derivatives to net income	(7)	31
Foreign currency translation adjustments	(43)	38
Adjustments to pension and other postretirement benefit plan liabilities, net of tax	1	(1)
Total Other Comprehensive Loss	(90)	(46)
Comprehensive Income	702	162
Comprehensive Income Attributable to Noncontrolling Interests	(8)	(1)
Comprehensive Income Attributable to Kinder Morgan Energy Partners, L.P.	$ 694	$ 161

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In Millions)

	March 31, 2013	December 31, 2012(a)
ASSETS	**(Unaudited)**	
Current assets		
Cash and cash equivalents	$ 736	$ 529
Accounts receivable, net of allowance	1,085	1,114
Inventories	352	338
Fair value of derivative contracts	33	55
Assets held for sale	32	211
Other current assets	124	130
Total Current assets	2,362	2,377
Property, plant and equipment, net	22,584	22,330
Investments	1,880	1,864
Goodwill	5,412	5,417
Other intangibles, net	1,123	1,142
Fair value of derivative contracts	552	634
Deferred charges and other assets	1,239	1,212
Total Assets	$ 35,152	$ 34,976
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Current portion of debt	$ 1,127	$ 1,155
Accounts payable	983	1,091
Accrued interest	184	327
Fair value of derivative contracts	49	21
Accrued other current liabilities	851	653
Total Current liabilities	3,194	3,247
Long-term liabilities and deferred credits		
Long-term debt		
Outstanding	16,829	15,907
Debt fair value adjustments	1,586	1,698
Total Long-term debt	18,415	17,605
Deferred income taxes	254	249
Fair value of derivative contracts	11	13
Other long-term liabilities and deferred credits	1,044	1,100
Total Long-term liabilities and deferred credits	19,724	18,967
Total Liabilities	22,918	22,214
Commitments and contingencies (Notes 3 and 9)		
Partners' Capital		
Common units	5,137	4,723
Class B units	13	14
i-units	3,676	3,564
General partner	3,008	4,026
Accumulated other comprehensive income	79	168
Total Kinder Morgan Energy Partners, L.P. Partners' Capital	11,913	12,495
Noncontrolling interests	321	267
Total Partners' Capital	12,234	12,762
Total Liabilities and Partners' Capital	$ 35,152	$ 34,976

The accompanying notes are an integral part of these consolidated financial statements.

(a) Retrospectively adjusted as discussed in Note 1.

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In Millions)
(Unaudited)

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
Cash Flows From Operating Activities		
Net Income	$ 792	$ 208
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	328	246
Amortization of excess cost of equity investments	2	2
Gain from the sale of investments in Express pipeline system (Note 2)	(225)	—
Loss from the sale of discontinued operations and the remeasurement of FTC Natural Gas Pipelines disposal group to fair value (Note 2)	2	322
Earnings from equity investments	(83)	(87)
Distributions from equity investments	82	80
Changes in components of working capital:		
Accounts receivable	21	83
Inventories	(13)	(77)
Other current assets	24	41
Accounts payable	(161)	(61)
Accrued interest	(143)	(162)
Accrued other current liabilities	208	105
Rate reparations, refunds and other litigation reserve adjustments	15	—
Other, net	(103)	(42)
Net Cash Provided by Operating Activities	746	658
Cash Flows From Investing Activities		
Payment to KMI for drop-down asset group (Note 2)	(988)	—
Acquisitions of assets and investments	(4)	(30)
Capital expenditures	(552)	(353)
Proceeds from sale of investments in Express pipeline system	403	—
Contributions to equity investments	(40)	(49)
Distributions from equity investments in excess of cumulative earnings	19	43
Other, net	(9)	16
Net Cash Used in Investing Activities	(1,171)	(373)
Cash Flows From Financing Activities		
Issuance of debt	2,699	2,420
Payment of debt	(1,809)	(2,160)
Debt issue costs	(7)	(6)
Proceeds from issuance of common units	385	124
Contributions from noncontrolling interests	65	2
Pre-acquisition contributions and distributions from KMI to drop-down asset group	35	—
Distributions to partners and noncontrolling interests:		
Common units	(326)	(270)
Class B units	(7)	(6)
General Partner	(388)	(307)
Noncontrolling interests	(9)	(7)
Net Cash Provided by (Used in) Financing Activities	638	(210)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	(6)	7
Net increase in Cash and Cash Equivalents	207	82
Cash and Cash Equivalents, beginning of period	529	409
Cash and Cash Equivalents, end of period	$ 736	$ 491

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)
(In Millions)
(Unaudited)

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
Noncash Investing and Financing Activities		
Assets acquired or liabilities settled by the issuance of common units	$ 108	$ 7
Increase in accrual for construction costs	$ 51	$ 13
Supplemental Disclosures of Cash Flow Information		
Cash paid during the period for interest (net of capitalized interest)	$ 318	$ 272
Cash paid during the period for income taxes	$ 3	$ 4

The accompanying notes are an integral part of these consolidated financial statements.

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. General

Organization

Kinder Morgan Energy Partners, L.P. is a leading pipeline transportation and energy storage company in North America, and unless the context requires otherwise, references to “we,” “us,” “our,” “KMP” or the “Partnership” are intended to mean Kinder Morgan Energy Partners, L.P., our operating limited partnerships and their majority-owned and controlled subsidiaries. We own an interest in or operate approximately 44,000 miles of pipelines and 180 terminals, and conduct our business through five reportable business segments (described further in Note 7). We trade on the New York Stock Exchange under the symbol “KMP.”

Our pipelines transport natural gas, refined petroleum products, crude oil, carbon dioxide and other products, and our terminals store petroleum products and chemicals, and handle such products as ethanol, coal, petroleum coke and steel. We are also the leading producer and transporter of carbon dioxide, commonly called CO_2, for enhanced oil recovery projects in North America.

Kinder Morgan, Inc. and Kinder Morgan G.P., Inc.

Kinder Morgan, Inc., a Delaware corporation and referred to as KMI in this report, indirectly owns all the common stock of our general partner, Kinder Morgan G.P., Inc., a Delaware corporation. In July 2007, our general partner issued and sold to a third party 100,000 shares of Series A fixed-to-floating rate term cumulative preferred stock due 2057. The consent of holders of a majority of these preferred shares is required with respect to a commencement of or a filing of a voluntary bankruptcy proceeding with respect to us or two of our subsidiaries, SFPP, L.P. and Calnev Pipe Line LLC.

KMI’s common stock trades on the New York Stock Exchange under the symbol “KMI.” As of March 31, 2013, KMI and its consolidated subsidiaries owned, through KMI’s general and limited partner interests in us and its ownership of shares issued by Kinder Morgan Management, LLC (discussed following), an approximate 13.0% interest in us.

Effective May 25, 2012, KMI acquired all of the outstanding shares of El Paso Corporation, a Delaware corporation referred to as EP in this report. KMI’s acquisition of EP created one of the largest energy companies in the United States. As a result, KMI owns a 41% limited partner interest and the 2% general partner interest in El Paso Pipeline Partners, L.P.

Kinder Morgan Management, LLC

Kinder Morgan Management, LLC, referred to as KMR in this report, is a Delaware limited liability company. Our general partner owns all of KMR’s voting securities and, pursuant to a delegation of control agreement, has delegated to KMR, to the fullest extent permitted under Delaware law and our partnership agreement, all of its power and authority to manage and control our business and affairs, except that KMR cannot take certain specified actions without the approval of our general partner. KMR’s shares representing limited liability company interests trade on the New York Stock Exchange under the symbol “KMR.” As of March 31, 2013, KMR, through its sole ownership of our i-units, owned approximately 30.7% of all of our outstanding limited partner units (all of our i-units are issued only to KMR).

More information about the entities referred to above and the delegation of control agreement is contained in our Annual Report on Form 10-K for the year ended December 31, 2012. In this report, we refer to our Annual Report on Form 10-K for the year ended December 31, 2012 as our 2012 Form 10-K.

Basis of Presentation

General

We have prepared our accompanying unaudited consolidated financial statements under the rules and regulations of the United States Securities and Exchange Commission. These rules and regulations conform to the accounting principles contained in the Financial Accounting Standards Board’s Accounting Standards Codification. Under such rules and regulations, we have condensed or omitted certain information and notes normally included in financial statements prepared in conformity with the Codification. We believe, however, that our disclosures are adequate to make the information presented not misleading.

Our accompanying consolidated financial statements reflect normal adjustments, and also recurring adjustments that are, in the opinion of our management, necessary for a fair statement of our financial results for the interim periods, and certain amounts from prior periods have been reclassified to conform to the current presentation. Interim results are not necessarily indicative of results for a full year; accordingly, you should read these consolidated financial statements in conjunction with our consolidated financial statements and related notes included in our 2012 Form 10-K.

Our accounting records are maintained in United States dollars, and all references to dollars are United States dollars, except where stated otherwise. Canadian dollars are designated as C$. Our consolidated financial statements include our accounts and those of our operating partnerships and their majority-owned and controlled subsidiaries, and all significant intercompany items have been eliminated in consolidation.

Our financial statements are consolidated into the consolidated financial statements of KMI; however, except for the related party transactions described in Note 8 "Related Party Transactions—Asset Acquisitions," KMI is not liable for, and its assets are not available to satisfy, the obligations of us and/or our subsidiaries and vice versa. Responsibility for payments of obligations reflected in our or KMI's financial statements is a legal determination based on the entity that incurs the liability. Furthermore, the determination of responsibility for payment among entities in our consolidated group of subsidiaries is not impacted by the consolidation of our financial statements into the consolidated financial statements of KMI.

March 2013 KMI Asset Drop-Down

Effective March 1, 2013, we acquired from KMI the remaining 50% ownership interest we did not already own in both the El Paso Natural Gas pipeline system and the EP midstream assets for an aggregate consideration of approximately $1.7 billion (including our proportional 50% of assumed debt borrowings as of March 1, 2013). In this report, we refer to this acquisition of assets from KMI as the drop-down transaction; the combined group of assets acquired from KMI as the drop-down asset group; the El Paso Natural Gas pipeline system or El Paso Natural Gas Company, L.L.C. as EPNG; and the EP midstream assets or Kinder Morgan Altamont LLC (formerly, El Paso Midstream Investment Company, L.L.C.) as the midstream assets. We acquired our initial 50% ownership interest in EPNG from KMI effective August 1, 2012, and we acquired our initial 50% ownership interest in the midstream assets from an investment vehicle affiliated with Kohlberg Kravis Roberts & Co. L.P. (together with its affiliates, referred to as KKR) effective June 1, 2012. Prior to our acquisition from KMI, we accounted for our initial 50% interest in both EPNG and the midstream assets (the March 1, 2013 drop-down asset group) under the equity method of accounting.

KMI acquired a 100% ownership interest in EPNG and a 50% ownership interest in the midstream assets as part of its acquisition of EP on May 25, 2012 (discussed above). KMI accounted for its acquisition of the drop-down asset group under the acquisition method of accounting, and we accounted for the drop-down transaction as a combination of entities under common control. We prepared our consolidated financial statements to reflect the transfer of the remaining 50% ownership interests in EPNG and the midstream assets from KMI to us as if such transfers had taken place on the date when both EPNG and the midstream assets met the accounting requirements for entities under common control—May 25, 2012 for EPNG, and June 1, 2012 for the midstream assets. Specifically, we (i) consolidate our now 100% investments in both EPNG and the midstream assets having recognized the acquired assets and assumed liabilities at KMI's carrying value as of the effective dates of common control (including all of KMI's purchase accounting adjustments); (ii) recognized any difference between our purchase price and the carrying value of the net assets we acquired as an adjustment to our Partners' Capital (specifically, as an adjustment to our general partner's and our noncontrolling interests' capital interests); and (iii) retrospectively adjusted our consolidated financial statements, for any date after the effective dates of common control.

Additionally, because KMI both controls us and consolidates our financial statements into its consolidated financial statements as a result of its ownership of our general partner, we fully allocated to our general partner:

- the earnings of the drop-down asset group for the periods beginning on the effective dates of common control and ending March 1, 2013 (and we reported this amount separately as "Pre-acquisition income from operations of drop-down asset group allocated to General Partner" within the Calculation of Limited Partners' Interest in Net Income (Loss) section of our accompanying consolidated statement of income for the three months ended March 31, 2013); and

- incremental severance expense related to KMI's acquisition of EP and allocated to us from KMI (and we reported this amount separately as "Drop-down asset group severance expense allocated to General Partner" within the Calculation of Limited Partners' Interest in Net Income (Loss) section of our accompanying consolidated statement of income for the three months ended March 31, 2013). The severance expense allocated to us was associated with both the drop-down asset group and the assets we acquired from KMI effective August 1, 2012; however, we do not have any obligation, nor did we pay any amounts related to this expense.

For all periods beginning after our acquisition date of March 1, 2013, we allocated our earnings (including the earnings from the drop-down asset group) to all of our partners according to our partnership agreements.

FTC Natural Gas Pipelines Disposal Group – Discontinued Operations

Effective November 1, 2012, we sold our (i) Kinder Morgan Interstate Gas Transmission natural gas pipeline system; (ii) Trailblazer natural gas pipeline system; (iii) Casper and Douglas natural gas processing operations; and (iv) 50% equity investment in the Rockies Express natural gas pipeline system to Tallgrass Development, LP (now known as Tallgrass Energy Partners, LP) (Tallgrass) for approximately $1.8 billion in cash (before selling costs), or $3.3 billion including our share of joint venture debt. In this report, we refer to this combined group of assets as our FTC Natural Gas Pipelines disposal group. The sale of our FTC Natural Gas Pipelines disposal group satisfied the terms of a March 15, 2012 agreement between KMI and the U.S. Federal Trade Commission (FTC) to divest certain of our assets in order to receive regulatory approval for KMI's EP acquisition. For more information about the presentation of our FTC Natural Gas Pipelines disposal group as discontinued operations, see Note 2 "Summary of Significant Accounting Policies—Basis of Presentation—FTC Natural Gas Pipelines Disposal Group - Discontinued Operations" to our consolidated financial statements included in our 2012 Form 10-K.

Goodwill

We evaluate goodwill for impairment on May 31 of each year. There were no impairment charges resulting from our May 31, 2012 impairment testing, and no event indicating an impairment has occurred subsequent to that date.

Limited Partners' Net Income (Loss) per Unit

We compute Limited Partners' Net Income (Loss) per Unit by dividing our limited partners' interest in net income (loss) by the weighted average number of units outstanding during the period.

2. Acquisitions and Divestitures

Acquisitions

March 2013 KMI Asset Drop-Down

As discussed above in Note 1 "General", we acquired the drop-down asset group from KMI effective March 1, 2013. Our consideration to KMI consisted of (i) $988 million in cash; (ii) 1,249,452 common units (valued at $108 million based on the $86.72 closing market price of a common unit on the New York Stock Exchange on the March 1, 2013 issuance date); and (iii) $557 million in assumed debt (consisting of 50% of the outstanding principal amount of EPNG's debt borrowings as of March 1, 2013, excluding any debt fair value adjustments). The terms of the drop-down transaction were approved on behalf of KMI by the independent members of its board of directors and on our behalf by the audit committees and the boards of directors of both our general partner and KMR, in its capacity as the delegate of our general partner, following the receipt by the independent directors of KMI and the audit committees of our general partner and KMR of separate fairness opinions from different independent financial advisors.

The EPNG natural gas pipeline system collectively consists of both the 10,200-mile El Paso Natural Gas pipeline system and the 500-mile Mojave pipeline system. It has a design capacity of approximately 5.6 billion cubic feet per day of natural gas, and transports natural gas from the San Juan, Permian and Anadarko basins to California, other western states, Texas and northern Mexico. EPNG also provides up to 44 billion cubic feet of underground working natural gas storage capacity. The midstream assets include both the Altamont natural gas gathering, processing and treating assets located in the Uinta Basin in Utah, and the Camino Real natural gas and oil gathering system located in the Eagle Ford shale formation in South Texas. We included the drop-down asset group in our Natural Gas Pipelines reportable business segment.

August 2012 KMI Asset Drop-Down

Effective August 1, 2012, we acquired the full ownership interest in the Tennessee Gas natural gas pipeline system and an initial 50% ownership interest in EPNG from KMI for an aggregate consideration of approximately $6.2 billion. For additional information about this acquisition, see Note 2 “Summary of Significant Accounting Policies—Basis of Presentation—August 2012 KMI Asset Drop-Down” and Note 3 “Acquisitions and Divestitures—August 2012 KMI Asset Drop-Down” to our consolidated financial statements included in our 2012 Form 10-K. In this report, we refer to the Tennessee Gas natural gas pipeline system or our wholly-owned subsidiary Tennessee Gas Pipeline Company, L.L.C. as TGP.

Pro Forma Information

The following summarized unaudited pro forma consolidated income statement information for the three months ended March 31, 2012, assumes that our acquisition of TGP and our initial 50% ownership interest in EPNG had occurred as of January 1, 2012. We prepared the following unaudited pro forma financial results for comparative purposes only. The unaudited pro forma financial results may not be indicative of the results that would have occurred if we had completed our acquisition of TGP and our initial 50% interest in EPNG as of January 1, 2012 or the results that will be attained in the future. Amounts presented below are in millions, except for the per unit amounts:

	Pro Forma Three Months Ended March 31, 2012 (Unaudited)
Revenues	$ 2,116
Income from Continuing Operations	$ 579
Loss from Discontinued Operations	$ (272)
Net Income	$ 307
Net Income Attributable to Noncontrolling Interests	$ (2)
Net Income Attributable to Kinder Morgan Energy Partners, L.P.	$ 305
Limited Partners’ Net Income (Loss) per Unit:	
Income from Continuing Operations	$ 0.70
Loss from Discontinued Operations	(0.76)
Net Loss	$ (0.06)

Copano Energy, L.L.C.

On January 29, 2013, we and Copano Energy, L.L.C., referred to in this report as Copano, announced a definitive agreement whereby we will acquire all of Copano’s outstanding units, including convertible preferred units, for a total purchase price of approximately $5 billion, including the assumption of debt. The transaction, which has been approved by the board of directors of each of KMR, our general partner, and its delegate, as well as the board of directors of Copano, will be a 100% unit for unit transaction with an exchange ratio of 0.4563 of our common units for each Copano unit. The transaction is subject to customary closing conditions, regulatory approvals, and a vote of the Copano unitholders; however, TPG Advisors VI, Inc., Copano’s largest unitholder, has agreed to support the transaction and we expect the transaction to close in early May 2013.

Copano is a midstream natural gas company that provides comprehensive services to natural gas producers, including natural gas gathering, processing, treating and natural gas liquids fractionation. Copano owns an interest in or operates approximately 6,900 miles of pipelines with 2.7 billion cubic feet per day of natural gas transportation capacity, and also owns nine natural gas processing plants with more than 1 billion cubic feet per day of natural gas processing capacity and

315 million cubic feet per day of natural gas treating capacity. Its operations are located primarily in Texas, Oklahoma and Wyoming. Most of the acquired assets will be included in our Natural Gas Pipelines business segment.

Divestitures

FTC Natural Gas Pipelines Disposal Group – Discontinued Operations

As described above in Note 1 "General—Basis of Presentation," we began accounting for our FTC Natural Gas Pipelines disposal group as discontinued operations in the first quarter of 2012 (prior to KMI's sale announcement, we included the disposal group in our Natural Gas Pipelines business segment). During that quarter, we also remeasured the disposal group's net assets to reflect our initial assessment of its fair value as a result of the FTC mandated sale requirement, and based on this remeasurement, we recognized a $322 million loss. We reported this loss amount separately as "Loss on sale and the remeasurement of FTC Natural Gas Pipelines disposal group to fair value" within the discontinued operations section of our accompanying consolidated statement of income for the three months ended March 31, 2012. The final consideration was trued up in the first quarter of 2013 resulting in a $2 million additional loss recorded as "Loss on sale and the remeasurement of FTC Natural Gas Pipelines disposal group to fair value." As a result of our remeasurement of net assets to fair value and the sale of net assets, we recognized a combined $829 million loss for the year ended December 31, 2012.

Summarized financial information for the disposal group is as follows (in millions):

	Three Months Ended March 31, 2012
Operating revenues	$ 71
Operating expenses	(37)
Depreciation and amortization	(7)
Earnings from equity investments	22
Interest income and Other, net	1
Income from operations of FTC Natural Gas Pipelines disposal group	$ 50

Express Pipeline System

Effective March 14, 2013, we sold both our one-third equity ownership interest in the Express pipeline system and our subordinated debenture investment in Express to Spectra Energy Corp. for $403 million in cash. We recorded a pre-tax gain of $225 million with respect to this transaction, and we reported this amount separately as "Gain on sale of investments in Express pipeline system" in our accompanying consolidated statement of income for the three months ended March 31, 2013. We also recorded an income tax expense of $84 million related to this gain amount, and we included this expense within "Income Tax Expense" in our accompanying consolidated statement of income for the three months ended March 31, 2013. As of the date of sale, our equity investment in Express totaled $67 million and our note receivable due from Express totaled $110 million.

Prior to the sale, we (i) accounted for our equity investment under the equity method of accounting; (ii) accounted for our debt investment under the historical amortized cost method of accounting; and (iii) included the financial results of the Express pipeline system within our Kinder Morgan Canada business segment. As of December 31, 2012, our equity and debt investments in Express totaled $65 million and $114 million, respectively, and we included the combined $179 million amount within "Assets held for sale" on our accompanying consolidated balance sheet as of that date.

3. Debt

The following table summarizes the carrying value of our outstanding debt, excluding our debt fair value adjustments, as of March 31, 2013 and December 31, 2012 (in millions):

	March 31, 2013	December 31, 2012
Current portion of debt(a)	$ 1,127	$ 1,155
Long-term portion of debt	16,829	15,907
Carrying value of debt(b)	$ 17,956	$ 17,062

(a) As of March 31, 2013 and December 31, 2012, includes commercial paper borrowings of $595 million and $621 million, respectively.

(b) Excludes debt fair value adjustments. As of March 31, 2013 and December 31, 2012, our "Debt fair value adjustments" increased our debt balances by $1,586 million and $1,698 million, respectively. In addition to all unamortized debt discount/premium amounts and purchase accounting on our debt balances, our debt fair value adjustments also include (i) amounts associated with the offsetting entry for hedged debt; and (ii) any unamortized portion of proceeds received from the early termination of interest rate swap agreements. For further information about our debt fair value adjustments, see Note 5 "Risk Management—Fair Value of Derivative Contracts."

Changes in our outstanding debt, excluding debt fair value adjustments, during the three months ended March 31, 2013 are summarized as follows (in millions):

Debt borrowings	Interest rate	Increase / (decrease)	Cash received / (paid)
Issuances and assumptions			
Senior notes due September 1, 2023(a)	3.50%	$ 600	$ 598
Senior notes due March 1, 2043(a)	5.00%	400	398
Commercial paper	variable	1,689	1,689
Kinder Morgan Altamont LLC credit facility due August 2, 2014(b)	variable	14	14
Total increases in debt		$ 2,703	$ 2,699
Repayments and other			
Commercial paper	variable	(1,715)	(1,715)
Kinder Morgan Altamont LLC credit facility due August 2, 2014(b)	variable	(92)	(92)
Kinder Morgan Texas Pipeline, L.P. - senior notes due January 2, 2014	5.23%	(2)	(2)
Total decreases in debt		$ (1,809)	$ (1,809)

(a) On February 28, 2013, we completed a public offering of $1 billion in principal amount of senior notes in two separate series, consisting of $600 million of 3.50% notes due September 1, 2023 and $400 million of 5.00% notes due March 1, 2043. We received proceeds from the issuance of the notes, after deducting the underwriting discount, of $991 million, and we used the proceeds to pay a portion of the purchase price for our drop-down transaction and to reduce the borrowings under our commercial paper program.

(b) Our subsidiary, Kinder Morgan Altamont LLC maintains an unsecured revolving bank credit facility that matures on August 2, 2014. Effective March 31, 2013, Kinder Morgan Altamont LLC reduced the amount available for borrowing under this credit facility from $95 million to approximately $1 million. In addition, in February 2013, prior to our March 1, 2013 acquisition date, we and KMI each contributed $45 million to repay the outstanding $90 million borrowings under this credit facility, and following this repayment, Kinder Morgan Altamont LLC had no outstanding debt.

We also maintain a $2.2 billion senior unsecured revolving credit facility that matures July 1, 2016. Our credit facility can be amended to provide for borrowings of up to $2.5 billion, and borrowings under the facility can be used for general partnership purposes and as a backup for our commercial paper program. There were no borrowings under the credit facility as of March 31, 2013 or as of December 31, 2012. We had, as of March 31, 2013, $1,395 million of borrowing capacity available under our credit facility. The amount available for borrowing under our credit facility was reduced by a combined amount of $805 million, consisting of $595 million of commercial paper borrowings and $210 million of letters of credit, consisting of (i) a $100 million letter of credit that supports certain proceedings with the California Public Utilities Commission involving refined products tariff charges on the intrastate common carrier operations of our Pacific operations' pipelines in the state of California; (ii) a combined $85 million in three letters of credit that support tax-exempt bonds; and (iii) a combined $25 million in other letters of credit supporting other obligations of us and our subsidiaries.

For additional information regarding our debt facilities and for information on our contingent debt agreements, see Note 8 "Debt" and Note 12 "Commitments and Contingent Liabilities" to our consolidated financial statements included in our 2012 Form 10-K.

4. Partners' Capital

Limited Partner Units

As of March 31, 2013 and December 31, 2012, our Partners' Capital included the following limited partner units:

	March 31, 2013	December 31, 2012
Common units:		
Held by third parties	236,318,422	231,718,422
Held by KMI and affiliates (excluding our general partner)	20,563,455	19,314,003
Held by our general partner	1,724,000	1,724,000
Total Common units	258,605,877	252,756,425
Class B units(a)	5,313,400	5,313,400
i-units(b)	116,922,934	115,118,338
Total limited partner units	380,842,211	373,188,163

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(a) As of both March 31, 2013 and December 31, 2012, all of our Class B units were held by a wholly-owned subsidiary of KMI. The Class B units are similar to our common units except that they are not eligible for trading on the New York Stock Exchange.

(b) As of both March 31, 2013 and December 31, 2012, all of our i-units were held by KMR. Our i-units are a separate class of limited partner interests in us and are not publicly traded. In accordance with its limited liability company agreement, KMR's activities are restricted to being a limited partner in us, and to controlling and managing our business and affairs and the business and affairs of our operating limited partnerships and their subsidiaries. Through the combined effect of the provisions in our partnership agreement and the provisions of KMR's limited liability company agreement, the number of outstanding KMR shares and the number of our i-units will at all times be equal. The number of i-units we distribute to KMR is based upon the amount of cash we distribute to the owners of our common units. When cash is paid to the holders of our common units, we issue additional i-units to KMR. The fraction of an i-unit paid per i-unit owned by KMR will have a value based on the cash payment on the common units.

The total limited partner units represent our limited partners' interest and an effective 98% interest in us, exclusive of our general partner's incentive distribution rights. Our general partner has an effective 2% interest in us, excluding its right to receive incentive distributions.

Changes in Partners' Capital

For each of the three month periods ended March 31, 2013 and 2012, changes in the carrying amounts of our Partners' Capital attributable to both us and our noncontrolling interests, including our comprehensive income are summarized as follows (in millions):

	Three Months Ended March 31,					
	2013			2012		
	KMP	Noncontrolling Interests	Total	KMP	Noncontrolling interests	Total
Beginning Balance	$ 12,495	$ 267	$ 12,762	$ 7,508	$ 96	$ 7,604
Units issued for cash	385	—	385	124	—	124
Units issued as consideration in the acquisition of assets(a)	108	—	108	7	—	7
Distributions paid in cash	(721)	(9)	(730)	(583)	(7)	(590)
Adjustments to capital due to acquisitions from KMI(a)	(1,051)	(10)	(1,061)	—	—	—
Noncash compensation expense allocated from KMI(b)	1	—	1	—	—	—
Cash contributions	—	65	65	—	2	2
Other adjustments	2	—	2	—	2	2
Comprehensive income	694	8	702	161	1	162
Ending Balance	$ 11,913	$ 321	$ 12,234	$ 7,217	$ 94	$ 7,311

(a) Amounts relate to the drop-down transaction, described in Note 2 "Acquisitions and Divestitures—Acquisitions—March 2013 KMI Asset Drop-Down." We determined that this drop-down transaction constituted a combination of entities under common control, and accordingly, we recognized the assets we acquired and the liabilities we assumed at KMI's carrying value (including all purchase accounting adjustments from KMI's acquisition of the drop-down asset group). We then recognized the difference between the carrying value of the assets acquired and liabilities assumed as an adjustment to our Partners' Capital (these asset, liability and partner capital adjustments are all included in our December 31, 2012 balance sheet). In the first quarter of 2013, we paid to KMI $988 million in cash, issued to KMI 1,249,452 common units valued at $108 million, and recognized a $1,061 million decrease in our Partners' Capital. As of March 31, 2013, the combined carrying value of the assets we acquired and the liabilities we assumed (including acquired cash balances and the contributions and distributions we received from KMI for periods prior to our acquisition date of March 1, 2013) totaled $1,168 million. In combination, the inclusion of the acquired net assets and the consideration paid to KMI resulted in a non-cash increase of $72 million in our Partners' Capital as of March 31, 2013. The increase to Partners' Capital consisted of a $71 million increase in our general partner's 1% general partner capital interest in us, and a $1 million increase in our general partner's 1.0101% general partner capital interest in our subsidiary Kinder Morgan Operating L.P. "A" (a noncontrolling interest to us).

(b) We do not have any obligation, nor did we pay any amounts related to this expense. For further information about this expense, see Note 1 "General—Basis of Presentation—March 2013 KMI Asset Drop-Down."

During each of the three month periods ended March 31, 2013 and 2012, there were no material changes in our ownership interests in subsidiaries in which we retained a controlling financial interest.

Equity Issuances

For the three month period ended March 31, 2013, our significant equity issuances consisted of the following:

- on February 26, 2013, we issued, in a public offering, 4,600,000 of our common units at a price of $86.35 per unit, less commissions and underwriting expenses. We received net proceeds, after deducting the underwriter discount, of $385 million for the issuance of these 4,600,000 common units, and we used the proceeds to pay a portion of the purchase price for the drop-down transaction; and

- On March 1, 2013, in connection with the drop-down transaction, we issued 1,249,452 of our common units to KMI. We valued the units at $108 million, based on the $86.72 closing market price of a common unit on the New York Stock Exchange on March 1, 2013. For more information on the drop-down transaction, see Note 2 "Acquisitions and Divestitures—Acquisitions—March 2013 KMI Asset Drop-Down."

Income Allocation and Declared Distributions

For the purposes of maintaining partner capital accounts, our partnership agreement specifies that items of income and loss shall be allocated among the partners, other than owners of i-units, in accordance with their percentage interests. Normal allocations according to percentage interests are made, however, only after giving effect to any priority income allocations in an amount equal to the incentive distributions that are allocated 100% to our general partner. Incentive distributions are generally defined as all cash distributions paid to our general partner that are in excess of 2% of the aggregate value of cash and i-units being distributed, and we determine the allocation of incentive distributions to our general partner by the amount quarterly distributions to unitholders exceed certain specified target levels, according to the provisions of our partnership agreement.

The following table provides information about our distributions for the three month periods ended March 31, 2013 and 2012 (in millions except per unit and i-Unit distributions amounts):

	Three Months Ended March 31,			
	2013		2012	
Per unit cash distribution declared	$	1.30	$	1.20
Per unit cash distribution paid(a)	$	1.29	$	1.16
Cash distributions paid to all partners(b)(c)	$	730	$	590
i-Unit distributions made to KMR(d)		1,804,596		1,464,145
General Partner's incentive distribution(e):				
Declared	$	398	$	319
Paid(a)(c)	$	384	$	302

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(a) Distributions for the fourth quarter of each year are declared and paid during the first quarter of the following year.

(b) Consisting of our common and Class B unitholders, our general partner and noncontrolling interests.

(c) The quarter-to-quarter increase in distributions paid reflect the increase in amounts distributed per unit as well as the issuance of additional units; however, the overall increase in distributions paid was partially offset by decreases of $7 million and $8 million, in the incentive distribution we paid to our general partner in the first quarters of 2013 and 2012, respectively. The decreases represented waived incentive amounts related to common units issued to finance a portion of our July 2011 KinderHawk Field Services LLC acquisition. Beginning with our distribution payments for the quarterly period ended June 30, 2010, and ending with our distribution payments for the quarterly period ended March 31, 2013, our general partner agreed not to take certain incentive distributions related to our acquisition of KinderHawk Field Services LLC. For more information about our KinderHawk acquisition, see Note 3 "Acquisitions and Divestitures—Business Combinations and Acquisitions of Investments—(3) KinderHawk Field Services LLC (1 of 2)" and "—(6) KinderHawk Field Services LLC and EagleHawk Field Services LLC (2 of 2)" to our consolidated financial statements included in our 2012 Form 10-K.

(d) Under the terms of our partnership agreement, we agreed that we will not, except in liquidation, make a distribution on an i-unit other than in additional i-units or a security that has in all material respects the same rights and privileges as our i-units. The number of i-units we distribute to KMR is based upon the amount of cash we distribute to the owners of our common units. When cash is paid to the holders of our common units, we will issue additional i-units to KMR. The fraction of an i-unit paid per i-unit owned by KMR will have a value based on the cash payment on the common units. If additional units are distributed to the holders of our common units, we will issue an equivalent amount of i-units to KMR based on the number of i-units it owns. Based on the preceding, the i-units we distributed were based on the $1.29 and $1.16 per unit paid to our common unitholders during the first quarters of 2013 and 2012, respectively.

(e) Incentive distribution does not include the general partner's initial 2% distribution of available cash.

For additional information about our 2012 partnership distributions, see Note 16 "Litigation, Environmental and Other Contingencies" and Note 17 "Regulatory Matters" to our consolidated financial statements included in our 2012 Form 10-K.

Subsequent Events

On April 17, 2013, we declared a cash distribution of $1.30 per unit for the quarterly period ended March 31, 2013. The distribution will be paid on May 15, 2013 to unitholders of record as of April 29, 2013. Our common unitholders and our Class B unitholder will receive cash. KMR will receive a distribution of 1,726,952 additional i-units based on the $1.30 distribution per common unit. For each outstanding i-unit that KMR holds, a fraction of an i-unit (0.014770) will be issued. This fraction was determined by dividing:

- $1.30, the cash amount distributed per common unit

by

- $88.015, the average of KMR's shares' closing market prices from April 11-24, 2013, the ten consecutive trading days preceding the date on which the shares began to trade ex-dividend under the rules of the New York Stock Exchange.

5. Risk Management

Certain of our business activities expose us to risks associated with unfavorable changes in the market price of natural gas, natural gas liquids and crude oil. We also have exposure to interest rate risk as a result of the issuance of our debt obligations. Pursuant to our management's approved risk management policy, we use derivative contracts to hedge or reduce our exposure to certain of these risks.

Energy Commodity Price Risk Management

As of March 31, 2013, we had entered into the following outstanding commodity forward contracts to hedge our forecast energy commodity purchases and sales:

	Net open position long/(short)	
Derivatives designated as hedging contracts		
Crude oil fixed price	(21.4)	million barrels
Natural gas fixed price	(33.9)	billion cubic feet
Natural gas basis	(34.4)	billion cubic feet
Derivatives not designated as hedging contracts		
Crude oil fixed price	(0.1)	million barrels
Crude oil basis	(3.6)	million barrels
Natural gas fixed price	(2.0)	billion cubic feet
Natural gas basis	12.2	billion cubic feet

As of March 31, 2013, the maximum length of time over which we have hedged our exposure to the variability in future cash flows associated with energy commodity price risk is through December 2016.

Interest Rate Risk Management

As of both March 31, 2013 and December 31, 2012, we had a combined notional principal amount of $5,525 million of fixed-to-variable interest rate swap agreements, effectively converting the interest expense associated with certain series of our senior notes from fixed rates to variable rates based on an interest rate of London InterBank Offered Rate (LIBOR) plus a spread. All of our swap agreements have termination dates that correspond to the maturity dates of the related series of senior notes and, as of March 31, 2013, the maximum length of time over which we have hedged a portion of our exposure to the variability in the value of this debt due to interest rate risk is through March 15, 2035.

Fair Value of Derivative Contracts

The fair values of our current and non-current asset and liability derivative contracts are each reported separately as "Fair value of derivative contracts" in the respective sections of our accompanying consolidated balance sheets. The following table summarizes the fair values of our derivative contracts included on our accompanying consolidated balance sheets as of March 31, 2013 and December 31, 2012 (in millions):

Fair Value of Derivative Contracts

		Asset derivatives		Liability derivatives	
		March 31, 2013	December 31, 2012	March 31, 2013	December 31, 2012
	Balance sheet location	Fair value	Fair value	Fair value	Fair value
Derivatives designated as hedging contracts					
Energy commodity derivative contracts	Current-Fair value of derivative contracts	$ 19	$ 42	$ (45)	$ (18)
	Non-current-Fair value of derivative contracts	37	40	(8)	(11)
Subtotal		56	82	(53)	(29)
Interest rate swap agreements	Current-Fair value of derivative contracts	7	9	—	—
	Non-current-Fair value of derivative contracts	515	594	(3)	(1)
Subtotal		522	603	(3)	(1)
Total		578	685	(56)	(30)
Derivatives not designated as hedging contracts					
Energy commodity derivative contracts	Current-Fair value of derivative contracts	7	4	(4)	(3)
	Non-current-Fair value of derivative contracts	—	—	—	(1)
Total		7	4	(4)	(4)
Total derivatives(a)		$ 585	$ 689	$ (60)	$ (34)

(a) As of March 31, 2013 and December 31, 2012, we presented the fair value of our derivative contracts on a gross basis on our accompanying consolidated balance sheets. If we had elected to net derivative contracts subject to master netting agreements as of March 31, 2013 and December 31, 2012, the impact would have reduced our derivative assets and liabilities by $18 million and $17 million, respectively. As of March 31, 2013 and December 31, 2012, we had cash margin deposits associated with our derivative contracts posted with counterparties of $21 million and $5 million, respectively, that would have additionally reduced our derivative liabilities.

Debt Fair Value Adjustments

The offsetting entry to adjust the carrying value of the debt securities whose fair value was being hedged is included within "Debt fair value adjustments" on our accompanying consolidated balance sheets. Our "Debt fair value adjustments" also include all unamortized debt discount/premium amounts, purchase accounting on our debt balances, and any unamortized portion of proceeds received from the early termination of interest rate swap agreements. These fair value adjustments to our debt balances included (i) $624 million and $638 million at March 31, 2013 and December 31, 2012, respectively, associated with fair value adjustments to our debt previously recorded in purchase accounting; (ii) $519 million and $602 million at March 31, 2013 and December 31, 2012, respectively, associated with the offsetting entry for hedged debt; (iii) $476 million and $488 million at March 31, 2013 and December 31, 2012, respectively, associated with unamortized premium from the termination of interest rate swap agreements; and offset by (iv) $33 million and $30 million at March 31, 2013 and December 31, 2012, respectively, associated with unamortized debt discount amounts. As of March 31, 2013, the weighted-average amortization period of the unamortized premium from the termination of the interest rate swaps was approximately 18 years.

Effect of Derivative Contracts on the Income Statement

The following two tables summarize the impact of our derivative contracts on our accompanying consolidated statements of income for each of the three months ended March 31, 2013 and 2012 (in millions):

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Derivatives in fair value hedging relationships	Location of gain/(loss) recognized in income on derivatives	Amount of gain/(loss) recognized in income on derivatives and related hedged item(a)	
		Three Months Ended March 31,	
		2013	2012
Interest rate swap agreements	Interest expense	$ (83)	$ (113)
Total		$ (83)	$ (113)
Fixed rate debt	Interest expense	$ 83	$ 113
Total		$ 83	$ 113

(a) Amounts reflect the change in the fair value of interest rate swap agreements and the change in the fair value of the associated fixed rate debt, which exactly offset each other as a result of no hedge ineffectiveness.

Derivatives in cash flow hedging relationships	Amount of gain/(loss) recognized in OCI on derivative (effective portion)(a)		Location of gain/(loss) reclassified from Accumulated OCI into income (effective portion)	Amount of gain/(loss) reclassified from Accumulated OCI into income (effective portion)(b)		Location of gain/(loss) recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)	Amount of gain/(loss) recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)	
	Three Months Ended March 31,			Three Months Ended March 31,			Three Months Ended March 31,	
	2013	2012		2013	2012		2013	2012
Energy commodity derivative contracts	$ (41)	$ (114)	Revenues-Natural gas sales	$ —	$ —	Revenues-Natural gas sales	$ —	$ —
			Revenues-Product sales and other	7	(29)	Revenues-Product sales and other	(3)	(3)
			Gas purchases and other costs of sales	—	(2)	Gas purchases and other costs of sales	—	—
Total	$ (41)	$ (114)	Total	$ 7	$ (31)	Total	$ (3)	$ (3)

(a) We expect to reclassify an approximate $14 million loss associated with energy commodity price risk management activities and included in our Partners' Capital as of March 31, 2013 into earnings during the next twelve months (when the associated forecasted sales and purchases are also expected to occur); however, actual amounts reclassified into earnings could vary materially as a result of changes in market prices.

(b) No material amounts were reclassified into earnings as a result of the discontinuance of cash flow hedges because it was probable that the original forecasted transactions would no longer occur by the end of the originally specified time period or within an additional two-month period of time thereafter, but rather, the amounts reclassified were the result of the hedged forecasted transactions actually affecting earnings (i.e., when the forecasted sales and purchase actually occurred).

Derivatives not designated as hedging contracts	Location of gain/(loss) recognized in income on derivative	Amount of gain/(loss) recognized in income on derivatives	
		Three Months Ended March 31,	
		2013	2012
Natural gas derivative contracts	Revenues-Natural gas sales	$ —	$ —
Crude oil derivative contracts	Revenues-Product sales and other	4	—
Total		$ 4	$ —

Credit Risks

We have counterparty credit risk as a result of our use of financial derivative contracts. Our counterparties consist primarily of financial institutions, major energy companies and local distribution companies. This concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions.

We maintain credit policies with regard to our counterparties that we believe minimize our overall credit risk. These policies include (i) an evaluation of potential counterparties' financial condition (including credit ratings); (ii) collateral requirements under certain circumstances; and (iii) the use of standardized agreements which allow for netting of positive and negative exposure associated with a single counterparty. Based on our policies, exposure, credit and other reserves, our management does not anticipate a material adverse effect on our financial position, results of operations, or cash flows as a result of counterparty performance.

Our over-the-counter swaps and options are entered into with counterparties outside central trading organizations such as futures, options or stock exchanges. These contracts are with a number of parties, all of which have investment grade credit ratings. While we enter into derivative transactions principally with investment grade counterparties and actively monitor their ratings, it is nevertheless possible that from time to time losses will result from counterparty credit risk in the future.

The maximum potential exposure to credit losses on our derivative contracts as of March 31, 2013 was as follows (in millions):

	Asset position
Interest rate swap agreements	$ 522
Energy commodity derivative contracts	63
Gross exposure	585
Netting agreement impact	(18)
Cash collateral held	—
Net exposure	$ 567

In conjunction with the purchase of exchange-traded derivative contracts or when the market value of our derivative contracts with specific counterparties exceeds established limits, we are required to provide collateral to our counterparties, which may include posting letters of credit or placing cash in margin accounts. As of both March 31, 2013 and December 31, 2012, we had no outstanding letters of credit supporting our hedging of energy commodity price risks associated with the sale of natural gas, natural gas liquids and crude oil. As of March 31, 2013 and December 31, 2012, we had cash margin deposits associated with our energy commodity contract positions and over-the-counter swap partners totaling $21 million and $5 million, respectively, and we included these deposit amounts within "Other current assets" in our accompanying consolidated balance sheets.

We also have agreements with certain counterparties to our derivative contracts that contain provisions requiring us to post additional collateral upon a decrease in our credit rating. As of March 31, 2013, we estimate that if our credit rating was downgraded one notch, we would be required to post no additional collateral to our counterparties. If we were downgraded two notches (that is, below investment grade), we would be required to post $13 million of additional collateral.

Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income

Changes in the components of our "Accumulated other comprehensive income" for the three months ended March 31, 2013 are summarized as follows (in millions):

	Net unrealized gains/(losses) on cash flow hedge derivatives	Foreign currency translation adjustments	Pension and other postretirement liability adjs.	Total Accumulated other comprehensive income/(loss)
Balance as of December 31, 2012	$ 66	$ 132	$ (30)	$ 168
Other comprehensive income before reclassifications	(40)	(43)	1	(82)
Amounts reclassified from accumulated other comprehensive income	(7)	—	—	(7)
Net current-period other comprehensive income	(47)	(43)	1	(89)
Balance as of March 31, 2013	$ 19	$ 89	$ (29)	$ 79

6. Fair Value

The fair values of our financial instruments are separated into three broad 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. Each fair value measurement must be assigned to a level corresponding to the lowest level input that is significant to the fair value measurement in its entirety.

The three broad levels of inputs defined by the fair value hierarchy are as follows:

- Level 1 Inputs—quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date;
- Level 2 Inputs—inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability; and
- Level 3 Inputs—unobservable inputs for the asset or liability. These unobservable inputs reflect the entity's own assumptions about the assumptions that market participants would use in pricing the asset or liability, and are developed based on the best information available in the circumstances (which might include the reporting entity's own data).

Fair Value of Derivative Contracts

The following two tables summarize the fair value measurements of our (i) energy commodity derivative contracts; and (ii) interest rate swap agreements as of March 31, 2013 and December 31, 2012, based on the three levels established by the Codification. The fair values of our current and non-current asset and liability derivative contracts are each reported separately as "Fair value of derivative contracts" in the respective sections of our accompanying consolidated balance sheets. The fair value measurements in the tables below do not include cash margin deposits made by us, which are reported within "Other current assets" in our accompanying consolidated balance sheets (in millions).

		Asset fair value measurements using		
	Total	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
As of March 31, 2013				
Energy commodity derivative contracts(a)	$ 63	$ 2	$ 57	$ 4
Interest rate swap agreements	$ 522	$ —	$ 522	$ —
As of December 31, 2012				
Energy commodity derivative contracts(a)	$ 86	$ 3	$ 76	$ 7
Interest rate swap agreements	$ 603	$ —	$ 603	$ —

	Liability fair value measurements using			
	Total	Quoted prices in active markets for identical liabilities (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
As of March 31, 2013				
Energy commodity derivative contracts(a)	$ (57)	$ (17)	$ (39)	$ (1)
Interest rate swap agreements	$ (3)	$ —	$ (3)	$ —
As of December 31, 2012				
Energy commodity derivative contracts(a)	$ (33)	$ (3)	$ (26)	$ (4)
Interest rate swap agreements	$ (1)	$ —	$ (1)	$ —

(a) Level 1 consists primarily of New York Mercantile Exchange (NYMEX) natural gas futures. Level 2 consists primarily of over-the-counter (OTC) West Texas Intermediate swaps and OTC natural gas swaps that are settled on NYMEX. Level 3 consists primarily of West Texas Intermediate options and West Texas Intermediate basis swaps.

The table below provides a summary of changes in the fair value of our Level 3 energy commodity derivative contracts for each of the three months ended March 31, 2013 and 2012 (in millions):

Significant unobservable inputs (Level 3)

	Three Months Ended March 31,	
	2013	2012
Derivatives-net asset (liability)		
Beginning of Period	$ 3	$ 7
Total gains or (losses):		
Included in earnings	6	2
Included in other comprehensive income	(1)	(22)
Purchases	—	3
Settlements	(5)	7
End of Period	$ 3	$ (3)
The amount of total gains for the period included in earnings attributable to the change in unrealized gains or losses relating to assets held at the reporting date	$ —	$ 2

As of March 31, 2013, our Level 3 derivative assets and liabilities consisted primarily of West Texas Intermediate (WTI) options and WTI basis swaps, where a significant portion of fair value is calculated from underlying market data that is not readily available. The derived values use industry standard methodologies that may consider the historical relationships among various commodities, modeled market prices, time value, volatility factors and other relevant economic measures. The use of these inputs results in our management's best estimate of fair value. For each of the three months ended March 31, 2013 and 2012, our Level 3 activity was not material.

Fair Value of Financial Instruments

The estimated fair value of our outstanding debt balance as of March 31, 2013 and December 31, 2012 (both short-term and long-term and including debt fair value adjustments), is disclosed below (in millions):

	March 31, 2013		December 31, 2012	
	Carrying Value	Estimated Fair value	Carrying Value	Estimated Fair value
Total debt	$ 19,542	$ 21,105	$ 18,760	$ 20,439

We used Level 2 input values to measure the estimated fair value of our outstanding debt balance as of both March 31, 2013 and December 31, 2012.

7. Reportable Segments

We divide our operations into five reportable business segments. These segments and their principal sources of revenues are as follows:

- Natural Gas Pipelines—the sale, transport, processing, treating, storage and gathering of natural gas;
- CO_2—the production and sale of crude oil from fields in the Permian Basin of West Texas and the transportation and marketing of carbon dioxide used as a flooding medium for recovering crude oil from mature oil fields;
- Products Pipelines— the transportation and terminaling of refined petroleum products, including gasoline, diesel fuel, jet fuel, natural gas liquids, crude and condensate, and bio-fuels;
- Terminals—the transloading and storing of refined petroleum products and dry and liquid bulk products, including coal, petroleum coke, cement, alumina, salt and other bulk chemicals; and
- Kinder Morgan Canada—the transportation of crude oil and refined products from Alberta, Canada to marketing terminals and refineries in British Columbia, the State of Washington and the Rocky Mountains and Central regions of the United States. As further described in Note 2, Kinder Morgan Canada divested its interest in the Express pipeline system effective March 14, 2013.

We evaluate performance principally based on each segment's earnings before depreciation, depletion and amortization expenses (including amortization of excess cost of equity investments), which excludes general and administrative expenses, third party debt costs and interest expense, unallocable interest income, and unallocable income tax expense. Our reportable segments are strategic business units that offer different products and services, and they are structured based on how our chief operating decision maker organizes their operations for optimal performance and resource allocation. Each segment is managed separately because each segment involves different products and marketing strategies.

Financial information by segment follows (in millions):

	Three Months Ended March 31,	
	2013	2012
Revenues		
Natural Gas Pipelines(a)	$ 1,369	$ 794
CO_2	429	417
Products Pipelines	454	223
Terminals	337	341
Kinder Morgan Canada	72	73
Total consolidated revenues	$ 2,661	1,848

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
Segment earnings before depreciation, depletion, amortization and amortization of excess cost of equity investments(b)		
Natural Gas Pipelines(a)	$ 557	$ 222
CO_2	342	334
Products Pipelines	185	176
Terminals	186	187
Kinder Morgan Canada(c)	193	50
Total segment earnings before DD&A	1,463	969
Total segment depreciation, depletion and amortization	(328)	(239)
Total segment amortization of excess cost of investments	(2)	(2)
General and administrative expenses	(134)	(107)
Interest expense, net of unallocable interest income	(202)	(139)
Unallocable income tax expense	(3)	(2)
Loss from discontinued operations	(2)	(272)
Total consolidated net income	$ 792	$ 208

	March 31, 2013	December 31, 2012
Assets		
Natural Gas Pipelines	$ 19,375	$ 19,403
CO_2	2,376	2,337
Products Pipelines	4,965	4,921
Terminals	5,350	5,123
Kinder Morgan Canada	1,688	1,903
Total segment assets	33,754	33,687
Corporate assets(d)	1,398	1,289
Total consolidated assets	$ 35,152	$ 34,976

(a) The increase in the 2013 amount versus the 2012 amount reflects our acquisition of the drop-down asset group from KMI effective March 1, 2013 (discussed further in Note 2 “Acquisitions and Discontinued Operations”).

(b) Includes revenues, earnings from equity investments, allocable interest income, and other, net, less operating expenses, allocable income taxes, and other expense (income).

(c) 2013 amount includes a $141 million increase in earnings from the after-tax gain on the sale of our investments in the Express pipeline system.

(d) Includes cash and cash equivalents; margin and restricted deposits; unallocable interest receivable, prepaid assets and deferred charges; and risk management assets related to debt fair value adjustments.

8. Related Party Transactions

Notes Receivable

Plantation Pipe Line Company

We and ExxonMobil have a term loan agreement covering a note receivable due from Plantation Pipe Line Company. We own a 51.17% equity interest in Plantation and our proportionate share of the outstanding principal amount of the note receivable was $49 million as of both March 31, 2013 and December 31, 2012. The note bears interest at the rate of 4.25% per annum and provides for semiannual payments of principal and interest on December 31 and June 30 each year, with a final principal payment of $45 million (for our portion of the note) due on July 20, 2016. We included $1 million of our note receivable balance within "Other current assets," on our accompanying consolidated balance sheets as of both March 31, 2013 and December 31, 2012, and we included the remaining outstanding balance within "Deferred charges and other assets."

Asset Acquisitions

From time to time in the ordinary course of business, we buy and sell pipeline and related services from KMI and its subsidiaries. Such transactions are conducted in accordance with all applicable laws and regulations and on an arms' length basis consistent with our policies governing such transactions. In conjunction with our acquisition of (i) certain Natural Gas Pipelines assets and partnership interests from KMI in December 1999 and December 2000; (ii) TransColorado Gas Transmission Company LLC from KMI in November 2004; (iii) TGP and 50% of EPNG from KMI in August 2012; and (iv) the remaining 50% ownership interest in EPNG from KMI in March 2013, KMI has agreed to indemnify us and our general partner with respect to approximately $5.9 billion of our debt. KMI would be obligated to perform under this indemnity only if we are unable, and/or our assets were insufficient, to satisfy our obligations.

Other

Generally, KMR makes all decisions relating to the management and control of our business, and in general, KMR has a duty to manage us in a manner beneficial to our unitholders. Our general partner owns all of KMR's voting securities and elects all of KMR's directors. KMI indirectly owns all the common stock of our general partner, and the officers of KMI have fiduciary duties to manage KMI, including selection and management of its investments in its subsidiaries and affiliates, in a manner beneficial to the owners of KMI. Accordingly, certain conflicts of interest could arise as a result of the relationships among KMR, our general partner, KMI and us.

The partnership agreements for us and our operating partnerships contain provisions that allow KMR to take into account the interests of parties in addition to us in resolving conflicts of interest, thereby limiting its duty to our unitholders, as well as provisions that may restrict the remedies available to our unitholders for actions taken that might, without such limitations, constitute breaches of duty. The partnership agreements also provide that in the absence of bad faith by KMR, the resolution of a conflict by KMR will not be a breach of any duties. The duty of the officers of KMI may, therefore, come into conflict with the duties of KMR and its directors and officers to our unitholders. The audit committee of KMR's board of directors will, at the request of KMR, review (and is one of the means for resolving) conflicts of interest that may arise between KMI or its subsidiaries, on the one hand, and us, on the other hand.

For a more complete discussion of our related party transactions, including (i) the accounting for our general and administrative expenses; (ii) KMI's operation and maintenance of the assets comprising our Natural Gas Pipelines business segment; and (iii) our partnership interests and distributions, see Note 11 "Related Party Transactions" to our consolidated financial statements included in our 2012 Form 10-K.

9. Litigation, Environmental and Other Contingencies

We are party to various legal, regulatory and other matters arising from the day-to-day operations of our businesses that may result in claims against the Partnership. Although no assurance can be given, we believe, based on our experiences to date and taking into account established reserves, that the ultimate resolution of such items will not have a material adverse impact on our business, financial position, results of operations or distributions to limited partners. We believe we have meritorious defenses to the matters to which we are a party and intend to vigorously defend the Partnership. When we determine a loss is probable of occurring and is reasonably estimable, we accrue an undiscounted liability for such contingencies based on our best estimate using information available at that time. If the estimated loss is a range of potential outcomes and there is no better estimate within the range, we accrue the amount at the low end of the range. We disclose contingencies where an adverse outcome may be material, or in the judgment of management, we conclude the matter should otherwise be disclosed.

Federal Energy Regulatory Commission Proceedings

The tariffs and rates charged by SFPP, L.P. (SFPP) and El Paso Natural Gas Company, LLC (EPNG) are subject to a number of ongoing proceedings at the FERC. A substantial portion of our legal reserves relate to these FERC cases and the CPUC cases described below them.

SFPP

The tariffs and rates charged by SFPP are subject to a number of ongoing proceedings at the FERC, including the complaints and protests of various shippers. In general, these complaints and protests allege the rates and tariffs charged by SFPP are not just and reasonable under the Interstate Commerce Act (ICA). If the shippers are successful in proving their claims, they are entitled to seek reparations (which may reach up to two years prior to the filing of their complaints) or refunds of any excess rates paid, and SFPP may be required to reduce its rates going forward. These proceedings tend to be protracted, with decisions of the FERC often appealed to the federal courts. The issues involved in these proceedings include, among others, whether indexed rate increases are justified, and the appropriate level of return and income tax allowance we may include in our rates. With respect to all of the SFPP proceedings at the FERC, we estimate that the shippers are seeking approximately $20 million in annual rate reductions and approximately $100 million in refunds. However, applying the principles of several recent FERC decisions in SFPP cases, as applicable, to other pending cases would result in substantially lower rate reductions and refunds than those sought by the shippers. We do not expect refunds in these cases to have an impact on our distributions to our limited partners.

EPNG

The tariffs and rates charged by EPNG are subject to two ongoing FERC proceedings (the "2008 rate case" and the "2010 rate case"). With respect to the 2008 rate case, the FERC issued its decision ("Opinion 517") in May 2012 and EPNG implemented certain aspects of that decision. The FERC subsequently issued an order requiring EPNG to decrease its rates related to the 2010 rate case in accordance with Opinion 517. EPNG has sought rehearing on that order as well as Opinion 517. With respect to the 2010 rate case, the presiding administrative law judge issued an initial decision in June 2012. This initial decision is currently being reviewed by the FERC. EPNG is pursuing settlement with its shippers in both open rate cases and believes the accruals established for these matters are adequate.

California Public Utilities Commission Proceedings

We have previously reported ratemaking and complaint proceedings against SFPP pending with the CPUC. The ratemaking and complaint cases generally involve challenges to rates charged by SFPP for intrastate transportation of refined petroleum products through its pipeline system in the state of California and request prospective rate adjustments and refunds with respect to tariffed and previously untariffed charges for certain pipeline transportation and related services. These matters have generally been consolidated and assigned to two administrative law judges.

On May 26, 2011, the CPUC issued a decision in several intrastate rate cases involving SFPP and a number of its shippers (the "Long" cases). The decision includes determinations on issues, such as SFPP's entitlement to an income tax allowance, allocation of environmental expenses, and refund liability which we believe are contrary both to CPUC policy and precedent and to established federal regulatory policies for pipelines. On March 8, 2012, the CPUC issued another decision related to the Long cases. This decision largely reflected the determinations made on May 26, 2011, including the denial of an income tax allowance for SFPP. The CPUC's order denied SFPP's request for rehearing of the CPUC's income tax allowance treatment, while granting requested rehearing of various, other issues relating to SFPP's refund liability and staying the payment of refunds until resolution of the outstanding issues on rehearing. On March 23, 2012, SFPP filed a petition for writ of review in the California Court of Appeals, seeking a court order vacating the CPUC's determination that SFPP is not entitled to recover an income tax allowance in its intrastate rates. The Court has granted review with respect to SFPP's petition and oral arguments were held on April 25, 2013.

On April 6, 2011, in proceedings unrelated to the above-referenced CPUC dockets, a CPUC administrative law judge issued a proposed decision (Bemesderfer case) substantially reducing SFPP's authorized cost of service and ordering SFPP to pay refunds from May 24, 2007 to the present of revenues collected in excess of the authorized cost of service. The proposed decision was subsequently withdrawn, and the presiding administrative law judge is expected to reissue a proposed decision at some indeterminate time in the future.

On January 30, 2012, SFPP filed an application reducing its intrastate rates by approximately 7%. This matter remains pending before the CPUC. The matter is scheduled for hearing in April, 2013, with a decision expected in the third or fourth quarter of 2013.

Based on our review of these CPUC proceedings and the shipper comments thereon, we estimate that the shippers are requesting approximately $375 million in reparation payments and approximately $30 million in annual rate reductions. The actual amount of reparations will be determined through further proceedings at the CPUC and, potentially, the California Court of Appeals. We believe that the appropriate application of the income tax allowance and corrections of errors in law and fact should result in a considerably lower amount. We do not expect any reparations that we would pay in these matters to have a material impact on our distributions to our limited partners.

Copano Shareholders' Litigation

Three putative class action lawsuits are currently pending in connection with our proposed merger with Copano: (i) Schultes v. Copano Energy, L.L.C., et al. (Case No. 06966), in the District Court of Harris County, Texas, which is referred to as the Texas State Action; (ii) Bruen v. Copano Energy, L.L.C., et al. (Case No. 4:13-CV-00540) in the United States District Court for the Southern District of Texas, which is referred to as the Texas Federal Action; and (iii) In re Copano Energy, L.L.C. Shareholder Litigation, Case No. 8284-VCN in the Court of Chancery of the State of Delaware, which is referred to as the Delaware Action, which reflects the consolidation of three actions originally filed in the Court of Chancery. The Texas State Action, the Texas Federal Action and the Delaware Action are collectively referred to as the "Actions."

The Actions name Copano, R. Bruce Northcutt, William L. Thacker, James G. Crump, Ernie L. Danner, T. William Porter, Scott A. Griffiths, Michael L. Johnson, Michael G. MacDougall, Kinder Morgan GP, Kinder Morgan Energy Partners and Merger Sub as defendants. The Actions are purportedly brought on behalf of a putative class seeking to enjoin the merger and allege, among other things, that the members of Copano's board of directors breached their fiduciary duties by agreeing to sell Copano for inadequate and unfair consideration and pursuant to an inadequate and unfair process, and that Copano, Kinder Morgan Energy Partners, Kinder Morgan GP and Merger Sub aided and abetted such alleged breaches. In addition, the plaintiffs in each of the Texas State Action and the Delaware Action allege that the Copano directors breached their duty of candor to unitholders by failing to provide the unitholders with all material information regarding the merger and/or made misstatements in the preliminary proxy statement. The plaintiffs in the Texas Federal Action also assert a claim under the federal securities laws alleging that the preliminary proxy statement omits and/or misrepresents material information in connection with the merger.

On April 21, 2013, the parties in all the Actions executed a Memorandum of Understanding by which, in exchange for the full settlement and dismissal with prejudice of each of the Actions, Copano agreed to make certain additional disclosures concerning the merger in a Form 8-K filed by Copano on April 22, 2013. The parties are in the process of preparing and filing a Stipulation of Settlement and such other additional documents as may be required to in the Delaware Chancery Court for approval of the settlement.

Other Commercial Matters

Union Pacific Railroad Company Easements

SFPP and UPRR are engaged in a proceeding to determine the extent, if any, to which the rent payable by SFPP for the use of pipeline easements on rights-of-way held by UPRR should be adjusted pursuant to existing contractual arrangements for the ten-year period beginning January 1, 2004 (*Union Pacific Railroad Company v. Santa Fe Pacific Pipelines, Inc., SFPP, L.P., Kinder Morgan Operating L.P. "D", Kinder Morgan G.P., Inc., et al.,* Superior Court of the State of California for the County of Los Angeles, filed July 28, 2004). In September 2011, the judge determined that the annual rent payable as of January 1, 2004 was $15 million, subject to annual consumer price index increases. SFPP intends to appeal the judge's determination, but if that determination is upheld, SFPP would owe approximately $75 million in back rent. Accordingly, during 2011, we increased our rights-of-way liability to cover this liability amount. In addition, the judge determined that UPRR is entitled to an estimated $20 million for interest on the outstanding back rent liability. We believe the award of interest is without merit and we are pursuing our appellate rights.

SFPP and UPRR are also engaged in multiple disputes over the circumstances under which SFPP must pay for a relocation of its pipeline within the UPRR right-of-way and the safety standards that govern relocations. In July 2006, a trial before a judge regarding the circumstances under which SFPP must pay for relocations concluded, and the judge determined that SFPP must pay for any relocations resulting from any legitimate business purpose of the UPRR. SFPP appealed this decision, and in December 2008, the appellate court affirmed the decision. In addition, UPRR contends that SFPP must comply with the more expensive AREMA standards in determining when relocations are necessary and in completing relocations. Each party is seeking declaratory relief with respect to its positions regarding the application of these standards with respect to relocations. A trial occurred in the fourth quarter of 2011, with a verdict having been reached that SFPP was obligated to comply with AREMA standards in connection with a railroad project in Beaumont Hills, California. SFPP is evaluating its post-trial and appellate options.

Since SFPP does not know UPRR's plans for projects or other activities that would cause pipeline relocations, it is difficult to quantify the effects of the outcome of these cases on SFPP. Even if SFPP is successful in advancing its positions, significant relocations for which SFPP must nonetheless bear the expense (i.e., for railroad purposes, with the standards in the federal Pipeline Safety Act applying) would have an adverse effect on our financial position, our results of operations, our cash flows, and our distributions to our limited partners. These effects would be even greater in the event SFPP is unsuccessful in one or more of these litigations.

Severstal Sparrows Point Crane Collapse

On June 4, 2008, a bridge crane owned by Severstal and located in Sparrows Point, Maryland collapsed while being operated by KMBT. According to our investigation, the collapse was caused by unexpected, sudden and extreme winds. On June 24, 2009, Severstal filed suit against KMBT in the United States District Court for the District of Maryland, Case No. 09CV1668-WMN. Severstal and its successor in interest, RG Steel, allege that KMBT was contractually obligated to replace the collapsed crane and that its employees were negligent in failing to properly secure the crane prior to the collapse. RG Steel seeks to recover in excess of $30 million for the alleged value of the crane and lost profits. KMBT denies each of RG Steel's allegations. On or about June 1, 2012, RG Steel filed for bankruptcy in Case No. 12-11669 in the United States Bankruptcy Court for the District of Delaware; consequently, the trial date has been postponed indefinitely.

Pipeline Integrity and Releases

From time to time, despite our best efforts, our pipelines experience leaks and ruptures. These leaks and ruptures may cause explosions, fire, and damage to the environment, damage to property and/or personal injury or death. In connection with these incidents, we may be sued for damages caused by an alleged failure to properly mark the locations of our pipelines and/or to properly maintain our pipelines. Depending upon the facts and circumstances of a particular incident, state and federal regulatory authorities may seek civil and/or criminal fines and penalties.

General

As of March 31, 2013 and December 31, 2012, we have recorded a total reserve for legal fees, transportation rate cases and other potential litigation liabilities in the amount of $431 million and $404 million, respectively. The reserve is primarily related to various claims from regulatory proceedings arising from our products pipeline and natural gas pipeline transportation rates. We regularly assess the likelihood of potential adverse outcomes in pending matters in order to determine the adequacy of our reserves.

Environmental Matters

We are subject to environmental cleanup and enforcement actions from time to time. In particular, the Comprehensive Environmental Response, Compensation and Liability Act, also know as CERCLA, generally imposes joint and several liability for cleanup and enforcement costs on current and predecessor owners and operators of a site, among others, without regard to fault or the legality of the original conduct, subject to the right of a liable party to establish a "reasonable basis" for apportionment of costs. Our operations are also subject to federal, state and local laws and regulations relating to protection of the environment. Although we believe our operations are in substantial compliance with applicable environmental law and regulations, risks of additional costs and liabilities are inherent in pipeline, terminal and carbon dioxide field and oil field operations, and there can be no assurance that we will not incur significant costs and liabilities. Moreover, it is possible that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies under the terms of authority of those laws, and claims for damages to property or persons resulting from our operations, could result in substantial costs and liabilities to us.

We are currently involved in several governmental proceedings involving alleged violations of environmental and safety regulations. As we receive notices of non-compliance, we attempt to negotiate and settle such matters where appropriate. Specifically, we are involved in matters including incidents at terminal facilities in New Jersey and Texas involving PHMSA and the Texas Commission on Environmental Quality, respectively, which may result in fines and penalties for alleged violations. We do not believe that these alleged violations will have a material adverse effect on our business, financial position, results of operations or distributions to limited partners.

We are also currently involved in several governmental proceedings involving groundwater and soil remediation efforts under administrative orders or related state remediation programs. We have established a reserve to address the costs associated with the cleanup.

In addition, we are involved with and have been identified as a potentially responsible party in several federal and state superfund sites. Environmental reserves have been established for those sites where our contribution is probable and reasonably estimable. In addition, we are from time to time involved in civil proceedings relating to damages alleged to have occurred as a result of accidental leaks or spills of refined petroleum products, natural gas liquids, natural gas and carbon dioxide.

Colorado Oil and Gas Conservation Commission Inspections

In Fall 2012, the Colorado Oil and Gas Conservation Commission (COGCC) performed inspections at multiple well sites in Southwestern Colorado owned by Kinder Morgan CO_2 Company, L.P. and some of these inspections resulted in alleged violations of COGCC's rules. Kinder Morgan took immediate steps to correct the alleged deficiencies and has engaged COGCC and other agencies in its efforts to maintain compliance. In April 2013, COGCC proposed a penalty of $300,000 to resolve the matter. We are evaluating the proposed penalty as well as potential responses to the alleged violations.

New Jersey Department of Environmental Protection v. Occidental Chemical Corporation, et al. (Defendants), Maxus Energy Corp. and Tierra Solutions, Inc. (Third Party Plaintiffs) v. 3M Company et al., Superior Court of New Jersey, Law Division - Essex County, Docket No. L-9868-05

The NJDEP sued Occidental Chemical and others under the New Jersey Spill Act for contamination in the Newark Bay Complex including numerous waterways and rivers. Occidental et al. then brought in approximately 300 third party defendants for contribution. NJDEP claimed damages related to forty years of discharges of TCDD (a form of dioxin), DDT and "other hazardous substances." GATX Terminals Corporation (n/k/a/ KMLT) was brought in as a third party defendant because of the noted hazardous substances language and because the Carteret, New Jersey facility (a former GATX Terminals facility) is located on the Arthur Kill River, one of the waterways included in the litigation. This case was filed against third party defendants in 2009. Recently, KMLT, as part of a joint defense group, entered a settlement agreement (Consent Judgment) with the NJDEP whereby the settling parties for a prescribed payment, get a contribution bar against first party defendants Occidental, Maxus and Tierra in addition to a release. This third-party Consent Judgment will be published in the New Jersey Register followed by a 60-day comment period after which it will be lodged with the court. Additionally, we have information that the NJDEP has reached an agreement in principle on terms for a settlement with Maxus and Tierra. Occidental is not part of the settlement. As part of this settlement, these defendants agree to dismiss all direct claims against third-party defendants and to not oppose the third-party settlement. We expect the first-party settlement to be finalized over the next 60 days. All discovery and trial proceedings are stayed during these settlement negotiations.

Portland Harbor Superfund Site, Willamette River, Portland, Oregon

In December 2000, the U.S. Environmental Protection Agency (U.S. EPA) sent out General Notice letters to potentially responsible parties including GATX Terminals Corporation (n/k/a KMLT). At that time, GATX owned two liquids terminals along the lower reach of the Willamette River, an industrialized area known as Portland Harbor. Portland Harbor is listed on the National Priorities List and is designated as a Superfund Site under CERCLA. A group of potentially responsible parties formed what is known as the Lower Willamette Group (LWG), of which KMLT is a nonvoting member and pays a minimal fee to be part of the group. The LWG agreed to conduct the Remedial Investigation and Feasibility Study leading to the proposed remedy for cleanup of the Portland Harbor site. Once the U.S. EPA determines the cleanup remedy from the remedial investigations and feasibility studies conducted during the last decade at the site, it will issue a Record of Decision. Currently, KMLT and 90 other parties are involved in an allocation process to determine each party's respective share of the cleanup costs. This is a non-judicial allocation process. We are participating in the allocation process on behalf of both KMLT and KMBT. Each entity has two facilities located in Portland Harbor. We expect the allocation to conclude in 2013 or 2014, depending upon when the U.S. EPA issues its Record of Decision.

Roosevelt Irrigation District v. Kinder Morgan G.P., Inc., Kinder Morgan Energy Partners, L.P. , U.S. District Court, Arizona

This is a CERCLA case brought against a number of defendants by a water purveyor whose wells have allegedly been contaminated due to the presence of a number of contaminants. The Roosevelt Irrigation District is seeking up to $175 million from approximately 70 defendants. The plume of contaminants has traveled under Kinder Morgan's Phoenix Terminal. The plaintiffs have advanced a novel theory that the releases of petroleum from the Phoenix Terminal (which are exempt under the petroleum exclusion under CERCLA) have facilitated the natural degradation of certain hazardous substances and thereby have resulted in a release of hazardous substances regulated under CERCLA. We are part of a joint defense group consisting of other terminal operators at the Phoenix Terminal including Chevron, BP, Salt River Project, Shell and a number of others, collectively referred to as the terminal defendants. Together, we filed a motion to dismiss all claims based on the petroleum exclusion under CERCLA. This case was assigned to a new judge, who has deemed all previous motions withdrawn and will grant leave to re-file such motions at a later date. We plan to re-file the motion to dismiss as well as numerous summary judgment motions as the judge allows.

The City of Los Angeles v. Kinder Morgan Liquids Terminals, LLC, Shell Oil Company, Equilon Enterprises LLC; California Superior Court, County of Los Angeles, Case No. NC041463

KMLT is a defendant in a lawsuit filed in 2005 alleging claims for environmental cleanup costs at the former Los Angeles Marine Terminal in the Port of Los Angeles. The lawsuit was stayed beginning in 2009 and remained stayed following the last case management conference in March 2013. During the stay, the parties deemed responsible by the local regulatory agency (including the City of Los Angeles) have worked with that agency concerning the scope of the required cleanup. We anticipate that cleanup activities by the Port at the site will begin in the summer of 2013. On April 9, 2013, KMLT and the Port of Los Angeles entered into a Settlement and Release Agreement the terms of which provide for the dismissal of the litigation by the Port upon the payment by KMLT of 60% of the Port's costs to remediate the former terminal site; the amount of payment not to exceed $15 million. The parties also filed a Good Faith Settlement motion in the Superior Court as part of the process of dismissal of the case. Further, according to terms of the Settlement and Release, we received a 5-year lease extension that allows KMLT to continue fuel loading and offloading operations at another KMLT Port of Los Angeles terminal property.

Exxon Mobil Corporation v. GATX Corporation, Kinder Morgan Liquids Terminals, LLC and ST Services, Inc.

On April 23, 2003, ExxonMobil filed a complaint in the Superior Court of New Jersey, Gloucester County. The lawsuit relates to environmental remediation obligations at a Paulsboro, New Jersey liquids terminal owned by ExxonMobil from the mid-1950s through November 1989, by GATX Terminals Corp. from 1989 through September 2000, and later owned by Support Terminals and Pacific Atlantic Terminals, LLC. The terminal is now owned by Plains Products, and it too is a party to the lawsuit.

On June 25, 2007, the NJDEP, the Commissioner of the New Jersey Department of Environmental Protection and the Administrator of the New Jersey Spill Compensation Fund, referred to collectively as the plaintiffs, filed a complaint against ExxonMobil and KMLT, formerly known as GATX Terminals Corporation, alleging natural resource damages related to historic contamination at the Paulsboro terminal. The complaint was filed in Gloucester County, New Jersey. Both ExxonMobil and KMLT filed third party complaints against Support Terminals/Plains and successfully brought Support Terminals/Plains into the case. The court consolidated the two cases.

In mid 2011, KMLT and Plains Products entered into a settlement agreement with the NJDEP for settlement of the state's alleged natural resource damages claim. The parties then entered into a Consent Judgment concerning the claim.

The natural resource damage settlement includes a monetary award of $1 million and a series of remediation and restoration activities at the terminal site. KMLT and Plains Products have joint responsibility for this settlement. Simultaneously, KMLT and Plains Products entered into a settlement agreement that settled each party's relative share of responsibility (50/50) to the NJDEP under the Consent Judgment noted above. The Consent Judgment is now entered with the Court and the settlement is final. According to the agreement, Plains will conduct remediation activities at the site and KMLT will provide oversight and 50% of the costs.

The settlement with the state did not resolve the original complaint brought by ExxonMobil. On or around, April 10, 2013, KMLT, Plains and ExxonMobil settled the original Exxon complaint for past remediation costs for $750,000 to be split 50/50 between KMLT and Plains. All parties have now executed the agreement and the litigation is settled and dismissed.

Mission Valley Terminal Lawsuit

In August 2007, the City of San Diego, on its own behalf and purporting to act on behalf of the People of the State of California, filed a lawsuit against us and several affiliates seeking injunctive relief and unspecified damages allegedly resulting from hydrocarbon and methyl tertiary butyl ether (MTBE) impacted soils and groundwater beneath the City's stadium property in San Diego arising from historic operations at the Mission Valley terminal facility. The case was filed in the Superior Court of California, San Diego County, case number 37-2007-00073033-CU-OR-CTL. On September 26, 2007, we removed the case to the United States District Court, Southern District of California, case number 07CV1883WCAB. The City disclosed in discovery that it is seeking approximately $170 million in damages for alleged lost value/lost profit from the redevelopment of the City's property and alleged lost use of the water resources underlying the property. Later, in 2010, the City amended its initial disclosures to add claims for restoration of the site as well as a number of other claims that increased their claim for damages to approximately $365 million.

In accordance with the Case Management Order, the parties filed their respective summary adjudication motions and motions to exclude experts on June 29, 2012. On November 29, 2012, the Court issued a Notice of Tentative Rulings on the parties' pending motions. The Court tentatively granted our motions to exclude certain of the City's proposed expert witnesses, tentatively granted our partial motions for summary judgment on the City's claims for water and real estate damages and the State's claims for violations of California Business and Professions Code § 17200, tentatively denied the City's motion for summary judgment on its claims of liability for nuisance and trespass, and tentatively granted our cross motion for summary judgment on such claims. On January 25, 2013, the Court issued its final order reaffirming in all respects its tentative rulings and rendered judgment in favor of all defendants on all claims asserted by the City. This site has been, and currently is, under the regulatory oversight and order of the California Regional Water Quality Control Board. SFPP continues to conduct an extensive remediation effort at the City's stadium property site.

Uranium Mines in Vicinity of Cameron, Arizona

In the 1950s and 1960s, Rare Metals Inc., an historical subsidiary of EPNG, operated approximately twenty uranium mines in the vicinity of Cameron, Arizona, many of which are located on the Navajo Indian Reservation. The mining activities were in response to numerous incentives provided to industry by the United States to locate and produce domestic sources of uranium to support the Cold War-era nuclear weapons program. In May 2012, EPNG received a general notice letter from the U.S. EPA notifying EPNG of the EPA's investigation of certain sites and its determination that the EPA considers EPNG to be a potentially responsible party within the meaning of CERCLA. In February 2013, the EPA delivered a proposed Administrative Order on Consent and proposed Scope of Work regarding the government's proposed next steps to investigate the mines. We are negotiating the terms and conditions of both the Administrative Order on Consent and the Scope of Work. We are also seeking contribution from the United States toward the cost of environmental activities associated with the mines, given its pervasive control over all aspects of the nuclear weapons program.

General

Although it is not possible to predict the ultimate outcomes, we believe that the resolution of the environmental matters set forth in this note, and other matters to which we are a party, will not have a material adverse effect on our business, financial position, results of operations or cash flows. However, we are not able to reasonably estimate when the eventual resolution of such claims will occur, and changing circumstances could cause these matters to have a material adverse impact. As of March 31, 2013 and December 31, 2012, we have accrued a total reserve for environmental liabilities in the amount of $163 million and $166 million, respectively. Additionally, many factors may change in the future affecting our reserve estimates, such as (i) regulatory changes; (ii) groundwater and land use near our sites; and (iii) changes in cleanup technology.

10. Regulatory Matters and Accounting for Regulatory Activities

Regulatory Assets and Liabilities

Regulatory assets and liabilities represent probable future revenues or expenses associated with certain charges and credits that will be recovered from or refunded to customers through the ratemaking process. We included the amounts of our regulatory assets and liabilities within “Other current assets,” “Deferred charges and other assets,” “Accrued other current liabilities” and “Other long-term liabilities and deferred credits,” respectively, in our accompanying consolidated balance sheets. The recovery period for these regulatory assets is approximately 20 years.

The following table summarizes our regulatory asset and liability balances (in millions):

	March 31, 2013	December 31, 2012
Current regulatory assets	$ 26	$ 18
Non-current regulatory assets	203	204
Total Regulatory Assets	$ 229	$ 222
Current regulatory liabilities	$ 4	$ 4
Non-current regulatory liabilities	62	65
Total Regulatory Liabilities	$ 66	$ 69

More information about our regulatory matters can be found in Note 17 “Regulatory Matters” to our consolidated financial statements that were included in our 2012 Form 10-K.

11. Recent Accounting Pronouncements

Accounting Standards Updates

None of the Accounting Standards Updates (ASU) that we adopted and that became effective January 1, 2013 (including (i) ASU No. 2011-11, “Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities;” (ii) ASU No. 2012-02, “Intangibles-Goodwill and Other (Topic 350): Testing Indefinite-Lived Intangible Assets for Impairment;” (iii) ASU No. 2013-01, “Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities;” and (iv) ASU No. 2013-02, “Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income”) had a material impact on our consolidated financial statements. More information about the four ASUs listed above can be found in Note 18 “Recent Accounting Pronouncements” to our consolidated financial statements that were included in our 2012 Form 10-K.

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

General and Basis of Presentation

The following discussion and analysis should be read in conjunction with (i) our accompanying interim consolidated financial statements and related notes (included elsewhere in this report); (ii) our consolidated financial statements and related notes included in our 2012 Form 10-K; and (iii) our management’s discussion and analysis of financial condition and results of operations included in our 2012 Form 10-K.

We prepared our consolidated financial statements in accordance with U.S. generally accepted accounting principles. In addition, as discussed in Note 1 "General" and Note 2 "Acquisitions and Discontinued Operations" to our consolidated financial statements included elsewhere in this report, our financial statements reflect:

- our March 1, 2013 acquisition of net assets from KMI as if such acquisition had taken place on the effective dates of common control pursuant to generally accepted accounting principles. We refer to this transfer of net assets from KMI to us as the drop-down transaction, and we refer to the transferred assets as our drop-down asset group. We accounted for the drop-down transaction as a combination of entities under common control, and accordingly, the financial information contained in this Management's Discussion and Analysis of Financial Condition and Results of Operations include the financial results of the drop-down asset group for all periods subsequent to the effective dates of common control; and

- the reclassifications necessary to reflect the results of our FTC Natural Gas Pipelines disposal group as discontinued operations. We sold our FTC Natural Gas Pipelines disposal group to Tallgrass Development, LP (now known as Tallgrass Energy Partners, LP) effective November 1, 2012 for approximately $1.8 billion in cash (before selling costs), or $3.3 billion including our share of joint venture debt. In the first quarter of 2013, following final working capital and other liability account reconciliations, we recorded an incremental loss of $2 million related to our sale of the disposal group, and except for this loss amount, we recorded no other financial results from the operations of the disposal group during the first quarter of 2013. Furthermore, we have excluded the disposal group's financial results from our Natural Gas Pipelines business segment disclosures for the three months ended March 31, 2012.

Critical Accounting Policies and Estimates

Accounting standards require information in financial statements about the risks and uncertainties inherent in significant estimates, and the application of U.S. generally accepted accounting principles involves the exercise of varying degrees of judgment. Certain amounts included in or affecting our consolidated financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions that cannot be known with certainty at the time our financial statements are prepared. These estimates and assumptions affect the amounts we report for our assets and liabilities, our revenues and expenses during the reporting period, and our disclosure of contingent assets and liabilities at the date of our financial statements. We routinely evaluate these estimates, utilizing historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from our estimates, and any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

Furthermore, with regard to goodwill impairment testing, we review our goodwill for impairment annually, and we evaluated our goodwill for impairment on May 31, 2012. Our goodwill impairment analysis performed on that date did not result in an impairment charge nor did our analysis reflect any reporting units at risk, and subsequent to that date, no event has occurred indicating that the implied fair value of each of our reporting units (including its inherent goodwill) is less than the carrying value of its net assets.

Further information about us and information regarding our accounting policies and estimates that we consider to be "critical" can be found in Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations" of our 2012 Form 10-K.

Results of Operations

In our discussions of the operating results of individual businesses that follow, we generally identify the important fluctuations between periods that are attributable to acquisitions and dispositions separately from those that are attributable to businesses owned in both periods.

Consolidated

Results of Operations

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012	Earnings increase/(decrease)	
	(In millions, except percentages)			
Segment earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments(a)				
Natural Gas Pipelines	$ 557	$ 222	$ 335	151 %
CO_2	342	334	8	2 %
Products Pipelines	185	176	9	5 %
Terminals	186	187	(1)	(1)%
Kinder Morgan Canada	193	50	143	286 %
Segment earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments (EBDA) (b)	1,463	969	494	51 %
Depreciation, depletion and amortization expense(c)	(328)	(239)	(89)	(37)%
Amortization of excess cost of equity investments	(2)	(2)	—	— %
General and administrative expense(d)	(134)	(107)	(27)	(25)%
Interest expense, net of unallocable interest income(e)	(202)	(139)	(63)	(45)%
Unallocable income tax expense	(3)	(2)	(1)	(50)%
Income from continuing operations	794	480	314	65 %
Loss from discontinued operations(f)	(2)	(272)	270	99 %
Net Income	792	208	584	281 %
Net Income attributable to noncontrolling interests(g)	(9)	(2)	(7)	(350)%
Net Income attributable to Kinder Morgan Energy Partners, L.P.	$ 783	$ 206	$ 577	280 %

(a) Includes revenues, earnings from equity investments, allocable interest income and other, net, less operating expenses, allocable income taxes, and other expense (income). Operating expenses include natural gas purchases and other costs of sales, operations and maintenance expenses, and taxes, other than income taxes.

(b) 2013 and 2012 amounts include an increase in earnings of $187 million and a decrease in earnings of $3 million, respectively, related to the combined effect from all of the 2013 and 2012 certain items impacting continuing operations and disclosed below in our management, discussion and analysis of segment results.

(c) 2013 amount includes a $19 million increase in expense attributable to our drop-down asset group for periods prior to our acquisition date of March 1, 2013.

(d) 2013 and 2012 amounts include increases in expense of $14 million and $1 million, respectively, related to the combined effect from the 2013 and 2012 certain items related to general and administrative expenses disclosed below in "—Other."

(e) 2013 amount includes a $15 million increase in expense attributable to our drop-down asset group for periods prior to our acquisition date of March 1, 2013.

(f) Represents amounts attributable to our FTC Natural Gas Pipelines disposal group. 2013 amount represents an incremental loss related to the sale of our disposal group effective November 1, 2012. 2012 amount includes a $322 million loss from a remeasurement of net assets to fair value, and $7 million of depreciation and amortization expense. The remaining 2012 amount ($57 million) represents our FTC Natural Gas Pipelines disposal group's earnings before depreciation, depletion and amortization expenses.

(g) 2013 and 2012 amounts include an increase of $2 million and a decrease of $4 million, respectively, in net income attributable to our noncontrolling interests, related to the combined effect from all of the 2013 and 2012 certain items disclosed below in both our management discussion and analysis of segment results and "—Other."

Distributable Cash Flow

As more fully described in our 2012 Form 10-K, we own and manage a diversified portfolio of energy transportation and storage assets, and primarily, our business model is designed to generate stable, fee-based income that provides overall long-term value to our unitholders. Our partnership agreement requires us to distribute 100% of our available cash to our partners on a quarterly basis (available cash as defined in our partnership agreement generally consists of all our cash receipts, less cash disbursements and changes in reserves). Distributable cash flow, sometimes referred to as DCF, is an overall performance metric we use as a measure of available cash, and the calculation of our DCF, for each of the three month periods ended March 31, 2013 and 2012 is as follows (calculated before the combined effect from all of the certain items disclosed in the footnotes to the tables above):

Distributable Cash Flow

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
Net Income	$ 792	$ 208
Add-back/(Less): Certain items - combined income (expense)(a)	(137)	326
Net Income before certain items	655	534
Less: Net Income before certain items attributable to noncontrolling interests	(7)	(6)
Net Income before certain items attributable to Kinder Morgan Energy Partners, L.P.	648	528
Less: General Partner's interest in Net Income before certain items(b)	(401)	(321)
Limited Partners' interest in Net Income before certain items	247	207
Depreciation, depletion and amortization(c)(e)	338	290
Book (cash) taxes paid, net	12	9
Incremental contributions from equity investments in the Express Pipeline and Endeavor Gathering LLC	1	—
Sustaining capital expenditures(d)(e)	(48)	(44)
Distributable cash flow (DCF) before certain items	$ 550	$ 462

(a) Equal to the combined effect from all of the 2013 and 2012 items disclosed in the footnotes to the "—Results of Operations" table included above.

(b) 2013 and 2012 amounts include reductions of $4 million and $6 million, respectively, for waived general partner incentive amounts related to common units issued to finance a portion of the July 2011 KinderHawk Field Services LLC acquisition.

(c) 2013 and 2012 amounts include expense amounts of $27 million and $42 million, respectively, for our proportionate share of the depreciation, depletion and amortization expenses of our unconsolidated joint ventures. 2013 amount also excludes a $19 million expense attributable to our drop-down asset group for periods prior to our acquisition date of March 1, 2013. 2012 amount also includes a $7 million expense attributable to our FTC Natural Gas Pipelines disposal group.

(d) 2012 amount includes expenditures of $2 million for our proportionate share of the sustaining capital expenditures of our unconsolidated joint ventures.

(e) DCF includes our proportionate share of the depreciation, depletion and amortization expenses of our unconsolidated joint ventures, less our proportionate share of the sustaining expenditures of our unconsolidated joint ventures, to more closely track the cash distributions we receive from these joint ventures.

With regard to our reportable business segments, we consider each period's earnings before all non-cash depreciation, depletion and amortization expenses, including amortization of excess cost of equity investments (defined in the "—Results of Operations" table above and sometimes referred to in this report as EBDA) to be an important measure of our success in maximizing returns to our partners. We also use segment EBDA internally as a measure of profit and loss used for evaluating segment performance and for deciding how to allocate resources to our five reportable business segments.

For the comparable first quarter periods of 2013 and 2012, total segment EBDA increased $494 million (51%) in 2013; however, this overall increase:

- included a $190 million increase in EBDA from the effect of the certain items referenced in footnote (b) to the "—Results of Operations" table above (which combined to increase total segment EBDA from continuing operations by $187 million in the first quarter of 2013 and decrease segment EBDA from continuing operations by $3 million in the first quarter of 2012); and

- excluded a $57 million decrease in quarter-to-quarter EBDA from discontinued operations.

After adjusting for these two items, the remaining $247 million (24%) increase in quarterly segment earnings before depreciation, depletion and amortization resulted primarily from better performance in the first quarter of 2013 from our Natural Gas Pipelines and Products Pipelines business segments. Combined EBDA from our CO_2, Terminals and Kinder Morgan Canada business segments were relatively flat across both comparable three-month periods.

Natural Gas Pipelines

	Three Months Ended March 31,	
	2013	2012
	(In millions, except operating statistics)	
Revenues(a)	$ 1,369	$ 794
Operating expenses(b)	(860)	(608)
Earnings from equity investments(c)	48	38
Interest income and Other, net	1	—
Income tax expense	(1)	(2)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments from continuing operations	557	222
Discontinued operations(d)	(2)	(265)
Earnings (loss) before depreciation, depletion and amortization expense and amortization of excess cost of equity investments including discontinued operations	$ 555	$ (43)
Natural gas transport volumes (Bcf)(e)	1,536.6	1,436.4
Natural gas sales volumes (Bcf)(e)	212.1	212.8

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(a) 2013 amount includes an increase of $111 million attributable to our drop-down asset group for periods prior to our acquisition date of March 1, 2013.

(b) 2013 amount includes an increase of $30 million attributable to our drop-down asset group for periods prior to our acquisition date of March 1, 2013, and a $1 million increase in expense related to hurricane clean-up and repair activities.

(c) 2013 amount includes a $19 million decrease in earnings attributable to our drop-down asset group for periods prior to our acquisition date of March 1, 2013, and a $1 million decrease in earnings from incremental severance expenses.

(d) Represents EBDA attributable to our FTC Natural Gas Pipelines disposal group. 2013 amount represents a $2 million loss from the sale of net assets. 2012 amount includes a $322 million loss from the remeasurement of net assets to fair value, and also includes revenues of $71 million.

(e) Includes pipeline volumes for TransColorado Gas Transmission Company LLC, Midcontinent Express Pipeline LLC, Kinder Morgan Louisiana Pipeline LLC, Fayetteville Express Pipeline LLC, Tennessee Gas Pipeline L.L.C., El Paso Natural Gas Pipeline Company, L.L.C., and the Texas intrastate natural gas pipeline group.

Combined, the certain items described in the footnotes to the table above (i) increased our Natural Gas Pipelines business segment's EBDA (including discontinued operations) by $380 million in the first quarter of 2013; and (ii) increased segment revenues (including discontinued operations) by $111 million in the first quarter of 2013, when compared to the year earlier first quarter. Following is information related to the increases and decreases, in the comparable three month periods of 2013 and 2012 and including discontinued operations, in the segment's remaining (i) $218 million (78%) increase in EBDA; and (ii) $393 million (45%) increase in operating revenues:

Three months ended March 31, 2013 versus Three months ended March 31, 2012

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Tennessee Gas Pipeline	$ 221	n/a	$ 266	n/a
El Paso Natural Gas Pipeline	46	n/a	45	n/a
El Paso Midstream asset operations	11	n/a	14	n/a
Eagle Ford Gathering(a)	8	490 %	n/a	n/a
Kinder Morgan Treating operations	(5)	(28)%	(2)	(6)%
Texas Intrastate Natural Gas Pipeline Group	(4)	(4)%	144	21 %
All others (including eliminations)	(2)	(2)%	(3)	(4)%
Total Natural Gas Pipelines-continuing operations	275	124 %	464	58 %
Discontinued operations(b)	(57)	(100)%	(71)	(100)%
Total Natural Gas Pipelines-including discontinued operations	$ 218	78 %	$ 393	45 %

n/a – not applicable

(a) Equity investment. We record earnings under the equity method of accounting, but we receive distributions in amounts essentially equal to equity earnings plus depreciation and amortization expenses less sustaining capital expenditures.

(b) Represents amounts attributable to our FTC Natural Gas Pipelines disposal group.

The primary increases and decreases in our Natural Gas Pipelines business segment's EBDA from continuing operations in the first quarter of 2013 compared to the first quarter of 2012 were attributable to the following:

- incremental earnings of $221 million from our Tennessee Gas Pipeline, which we acquired from KMI effective August 1, 2012;

- incremental earnings of $46 million from our El Paso Natural Gas Pipeline, which we acquired 50% from KMI effective August 1, 2012, and 50% from KMI effective March 1, 2013;

- incremental earnings of $11 million from the El Paso midstream assets we acquired 50% from Kohlberg Kravis Roberts & Co. L.P. effective June 1, 2012, and 50% from KMI effective March 1, 2013;

- incremental equity earnings of $8 million (490%) from our 50%-owned Eagle Ford Gathering LLC, due mainly to higher gathering volumes from the Eagle Ford natural gas shale formation in South Texas;

- a $5 million (28%) decrease from our Kinder Morgan natural gas treating operations, primarily due to lower margins from treating equipment manufacturing, and partly due to lower amine treating revenues; and

- a $4 million (4%) decrease from our Texas intrastate natural gas pipeline group. The decrease was primarily due to lower storage margins, and partly due to lower margins on natural gas processing activities. The decrease from storage activities was due mainly to timing differences on storage settlements, and the drop in processing margins was driven by lower natural gas liquids prices. The overall decrease in our intrastate group's earnings was partially offset by higher margins on natural gas sales, due to higher average natural gas sales prices relative to the first quarter of 2012, and higher natural gas delivery volumes to Mexico.

The quarter-to-quarter decrease in earnings before depreciation, depletion and amortization expenses from discontinued operations was due to the sale of our FTC Natural Gas Pipelines disposal group to Tallgrass effective November 1, 2012. For further information about this sale, see Note 1 "General—Basis of Presentation—FTC Natural Gas Pipelines Disposal Group – Discontinued Operations" to our consolidated financial statements included elsewhere in this report.

The overall changes in both segment revenues and segment operating expenses (from continuing operations and which include natural gas costs of sales) in the comparable three month periods of 2013 and 2012 primarily relate to the natural gas purchase and sale activities of our Texas intrastate natural gas pipeline group, with the variances from period-to-period in both revenues and operating expenses mainly due to corresponding changes in the intrastate group's average prices and volumes for natural gas purchased and sold. Our intrastate group both purchases and sells significant volumes of natural gas, which is often stored and/or transported on its pipelines, and because the group generally sells natural gas in the same price environment in which it is purchased, the increases and decreases in its gas sales revenues are largely offset by corresponding increases and decreases in its natural gas purchase costs. We realize earnings by capturing the favorable differences between the changes in its gas sales prices, purchase prices and transportation costs, including fuel. For the comparable first quarter periods of 2013 and 2012 our Texas intrastate natural gas pipeline group accounted for 66% and 86%, respectively, of the segment's revenues, and 88% and 96%, respectively, of the segment's operating expenses.

CO_2

	Three Months Ended March 31,	
	2013	**2012**
	(In millions, except operating statistics)	
Revenues(a)	$ 429	$ 417
Operating expenses	(92)	(87)
Earnings from equity investments	6	6
Income tax expense	(1)	(2)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 342	$ 334
Southwest Colorado carbon dioxide production (gross) (Bcf/d)(b)	1.2	1.2
Southwest Colorado carbon dioxide production (net) (Bcf/d)(b)	0.5	0.5
SACROC oil production (gross)(MBbl/d)(c)	30.7	26.9
SACROC oil production (net)(MBbl/d)(d)	25.6	22.4
Yates oil production (gross)(MBbl/d)(c)	20.5	21.2
Yates oil production (net)(MBbl/d)(d)	9.1	9.4
Katz oil production (gross)(MBbl/d)(c)	2.1	1.5
Katz oil production (net)(MBbl/d)(d)	1.7	1.3
Natural gas liquids sales volumes (net)(MBbl/d)(d)	10.3	9
Realized weighted average oil price per Bbl(e)	$ 86.85	$ 90.63
Realized weighted average natural gas liquids price per Bbl(f)	$ 46.48	$ 61.36

(a) 2013 and 2012 amounts include unrealized gains of $2 million and unrealized losses of $3 million, respectively, all relating to derivative contracts used to hedge forecasted crude oil sales.

(b) Includes McElmo Dome and Doe Canyon sales volumes.

(c) Represents 100% of the production from the field. We own an approximately 97% working interest in the SACROC unit, an approximately 50% working interest in the Yates unit, and an approximately 99% working interest in the Katz Strawn unit.

(d) Net to us, after royalties and outside working interests.

(e) Includes all of our crude oil production properties.

(f) Includes production attributable to leasehold ownership and production attributable to our ownership in processing plants and third party processing agreements.

Our CO_2 segment's primary businesses involve the production, marketing and transportation of both carbon dioxide (commonly called CO_2) and crude oil, and the production and marketing of natural gas and natural gas liquids. We refer to the segment's two primary businesses as its Oil and Gas Producing Activities and its Sales and Transportation Activities.

The certain items related to unrealized gains and losses on derivative contracts described in footnote (a) to the table above accounted for a $5 million increase in both segment EBDA and revenues in the first quarter of 2013, when compared to the first quarter of 2012. For each of the segment's two primary businesses, following is information related to the increases and decreases, in the comparable three month periods of 2013 and 2012, in the segment's remaining (i) $3 million (1%) increase in EBDA; and (ii) $7 million (2%) increase in operating revenues:

Three months ended March 31, 2013 versus Three months ended March 31, 2012

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Sales and Transportation Activities	$ 5	6 %	$ 4	5 %
Oil and Gas Producing Activities	(2)	(1)%	5	1 %
Intrasegment eliminations	—	— %	(2)	(16)%
Total CO_2	$ 3	1 %	$ 7	2 %

The increase in earnings before depreciation, depletion and amortization expenses from the segment's sales and transportation activities was driven by (i) higher reimbursable project revenues, largely related to the completion of prior expansion projects on the Central Basin pipeline system; (ii) higher third party storage revenues at the Yates field unit; and (iii) higher carbon dioxide sales revenues, due to a 1% increase in total carbon dioxide sales volumes.

Earnings for the comparable three month periods of 2013 and 2012 from the segment's oil and gas producing activities decreased slightly (1%) in the first quarter of 2013, versus the same quarter a year ago. The $5 million (1%) increase in operating revenues was offset by a $7 million (8%) increase in combined operating expenses, driven by an almost $5 million increase in well workover expenses. The increase in workover expenses was due to both increased drilling activity, relative to the first quarter of 2012, and higher prices charged by the industry's material and service providers, which impacted rig costs. The overall $5 million (1%) quarter-to-quarter increase in oil and gas related revenues included an $11 million (4%) increase in crude oil sales revenues (due to a 9% increase in sales volumes), partially offset by a $7 million (14%) decrease in plant product sales revenues (reflecting a 24% drop in our realized weighted average price per barrel of natural gas liquids).

Products Pipelines

	Three Months Ended March 31, 2013	2012
	(In millions, except operating statistics)	
Revenues	$ 454	$ 223
Operating expenses(a)	(281)	(57)
Other income	—	14
Earnings from equity investments	18	2
Income tax expense	(6)	(6)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 185	$ 176
Gasoline (MMBbl)(b)	97.8	95.1
Diesel fuel (MMBbl)	32.8	33.6
Jet fuel (MMBbl)	27.2	26.9
Total refined product volumes (MMBbl)(c)	157.8	155.6
Natural gas liquids (MMBbl)(d)	9.8	7.4
Condensate (MMBbl)(e)	2.0	—
Total delivery volumes (MMBbl)	169.6	163.0
Ethanol (MMBbl)(f)	8.7	7.3

(a) 2013 amount includes a $15 million increase in expense associated with a legal liability adjustment related to a certain West Coast terminal environmental matter.

(b) Volumes include ethanol pipeline volumes.

(c) Includes Pacific, Plantation, Calnev, and Central Florida pipeline volumes.

(d) Includes Cochin and Cypress pipeline volumes.

(e) Includes Crude Oil & Condensate pipeline volumes.

(f) Represents total ethanol volumes, including ethanol pipeline volumes included in gasoline volumes above.

The certain item described in footnote (a) to the table above accounted for a $15 million decrease in segment EBDA in the first quarter of 2013, when compared to the same quarter of 2012. Following is information related to the increases and decreases, in the comparable three month periods of both years, in the segment's (i) remaining $24 million (14%) increase in EBDA; and (ii) $231 million (104%) increase in operating revenues:

Three months ended March 31, 2013 versus Three months ended March 31, 2012

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Cochin Pipeline	$ 14	93 %	$ 13	67%
Transmix operations	6	76 %	212	n/a
Crude & Condensate Pipeline	3	197 %	5	n/a
Plantation Pipeline	2	14 %	—	—
All others (including eliminations)	(1)	(1)%	1	—
Total Products Pipelines	$ 24	14 %	$ 231	104%

The primary increases and decreases in our Products Pipelines business segment's EBDA in the comparable three month periods of 2013 and 2012 included the following:

- a $14 million (93%) increase from our Cochin Pipeline. The increase was largely revenue related, reflecting a 103% increase in pipeline throughput volumes, driven by incremental ethane/propane volumes as a result of pipeline modification projects completed in June 2012;

- a $6 million (76%) increase from our transmix processing operations. The increase was driven by higher margins on processing volumes, due mainly to favorable pricing, and by incremental earnings from third-party sales of excess renewable identification numbers (RINS), generated through our ethanol blending operations. The quarter-to-quarter increase in revenues was due mainly to the expiration of certain transmix fee-based processing agreements in March 2012. Due to the expiration of these contracts, we now directly purchase incremental transmix volumes and sell incremental volumes of refined products, resulting in both higher revenues and higher costs of sales expenses;

- incremental earnings of $3 million from our Kinder Morgan Crude Oil & Condensate Pipeline, which began transporting crude oil and condensate volumes from the Eagle Ford shale gas formation in South Texas to multiple terminaling facilities along the Texas Gulf Coast in October 2012; and

- a $2 million (14%) increase from our approximate 51% interest in the Plantation pipeline system—due largely to higher transportation revenues driven by both a 10% increase in system delivery volumes and higher average tariff rates since the end of the first quarter of 2012.

Terminals

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
	(In millions, except operating statistics)	
Revenues	$ 337	$ 341
Operating expenses(a)	(157)	(160)
Earnings from equity investments	7	6
Interest income and Other, net	1	—
Income tax expense	(2)	—
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 186	$ 187
Bulk transload tonnage (MMtons)(b)	22.2	25.0
Ethanol (MMBbl)	15.2	17.9
Liquids leaseable capacity (MMBbl)	60.7	59.8
Liquids utilization %(c)	95.4%	95.7%

(a) 2013 amount includes a $1 million increase in expense related to hurricane clean-up and repair activities at our New York Harbor and Mid-Atlantic terminals.

(b) Volumes for acquired terminals are included for all periods and include our proportionate share of joint venture tonnage.

(c) The ratio of our actual leased capacity to our estimated potential capacity.

Our Terminals business segment includes the operations of our petroleum, chemical and other liquids terminal facilities (other than those included in our Products Pipelines segment), and all of our coal, petroleum coke, fertilizer, steel, ores and other dry-bulk material services facilities. Including the certain item described in footnote (a) to the table above, which decreased segment EBDA by $1 million in the first quarter of 2013 compared to the first quarter of 2012, earnings before depreciation, depletion and amortization expenses from our Terminals segment were flat across both comparable first quarter periods of 2013 and 2012.

Following is information related to the increases and decreases, in the comparable three month periods of both years, in the segment's (i) EBDA (with no net overall change); and (ii) $4 million (1%) decrease in operating revenues:

Three months ended March 31, 2013 versus Three months ended March 31, 2012

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
West	$ 3	23 %	$ 4	15 %
Northeast	2	8 %	—	— %
Gulf Bulk	(3)	(18)%	(6)	(16)%
Ethanol	(2)	(27)%	(2)	(20)%
All others (including intrasegment eliminations and unallocated income tax expenses)	—	— %	—	— %
Total Terminals	$ —	— %	$ (4)	(1)%

The overall increases in earnings before depreciation, depletion and amortization from our Terminals segment was driven by higher contributions from West region terminals, due primarily to (i) incremental volumes from customer agreements at our Kinder Morgan Vancouver Wharves bulk marine terminal; (ii) higher capitalized overhead expenses due to ongoing terminal expansion projects; (iii) higher petroleum throughputs at our North 40 Edmonton, Canada facility; and (iv) higher soda ash volumes at our Portland, Oregon bulk terminal.

The increase in earnings from our Northeast terminal operations was driven by additional and restructured customer contracts at higher rates, and by an overall increase in chemical volumes. For all terminals combined, we also benefited from a 12% increase in export coal volumes, although we continued to experience weakness in domestic coal volumes. and we experienced lower business activity at various terminal sites primarily involved in the handling and storage of steel and alloy products, when compared to the first quarter of 2012.

Earnings before depreciation, depletion and amortization from both our Gulf Bulk and Ethanol handling terminals decreased in the first quarter of 2013 compared to the first quarter of 2012. The decrease from our Gulf Bulk facilities was driven by lower volumes from petroleum coke handling operations, due in large part to refinery and coker shutdowns as a result of turnarounds taken in the first quarter of 2013. The decrease in revenues and handling volumes from our combined Ethanol terminals was primarily due to the conversion to crude and vegetable oil at two terminals that handled ethanol, along with a decline in volumes at our coastal facilities attributable to increased import barrels. For all terminals included in our Terminals business segment, total ethanol handling volumes dropped 15% in the first quarter of 2013 compared to the first quarter of 2012.

Kinder Morgan Canada

	Three Months Ended March 31,	
	2013	2012
	(In millions, except operating statistics)	
Revenues	$ 72	$ 73
Operating expenses	(25)	(24)
Earnings from equity investments	4	1
Interest income and Other, net(a)	230	3
Income tax expense(b)	(88)	(3)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 193	$ 50
Transport volumes (MMBbl)(c)	26.7	24.9

(a) 2013 amount includes a $225 million gain from the sale of our equity and debt investments in the Express pipeline system.

(b) 2013 amount includes an $84 million increase in expense related to the gain associated with the sale of our equity and debt investments in the Express pipeline system described in footnote (a).

(c) Represents Trans Mountain pipeline system volumes.

Our Kinder Morgan Canada business segment includes the operations of our Trans Mountain and Jet Fuel pipeline systems, and until March 14, 2013, the effective date of sale, our one-third ownership interest in the Express crude oil pipeline system. The certain items relating to our sale of Express described in the footnotes to the table above increased segment earnings before depreciation, depletion and amortization by $141 million in the first quarter of 2013, when compared to the same quarter last year. For each of the segment's three primary businesses, following is information related to the increases and decreases, in the comparable three month periods of 2013 and 2012, related to the segment's (i) remaining $2 million (4%) increases in EBDA; and (ii) $1 million (1%) decrease in operating revenues:

Three months ended March 31, 2013 versus Three months ended March 31, 2012

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Trans Mountain Pipeline	$ 1	1%	$ (1)	(1)%
Express Pipeline(a)	1	34%	n/a	n/a
Jet Fuel Pipeline	—	—%	—	— %
Total Kinder Morgan Canada	$ 2	4%	$ (1)	(2)%

(a) Equity investment. We record earnings under the equity method of accounting.

Earnings before depreciation, depletion and amortization expenses from our Kinder Morgan Canada business segment were essentially unchanged across both comparable first quarter periods of 2013 and 2012. The quarter-to-quarter increase in Trans Mountain's earnings before depreciation, depletion and amortization expenses was mainly due to both higher non-operating income, related to incremental management incentive fees earned from its operation of the Express pipeline system, and to increased deliveries into Washington state on our Puget sound pipeline system. The increase in earnings from our equity investment in the Express pipeline system was primarily due to volumes moving at higher transportation rates on the Express portion of the system (on both Canadian and U.S delivery volumes).

Other

	Three Months Ended March 31,	
	2013	2012
	(In millions)	
General and administrative expenses(a)	$ 134	$ 107
Interest expense, net of unallocable interest income(b)	$ 202	$ 139
Unallocable income tax expense	$ 3	$ 2
Net income attributable to noncontrolling interests(c)	$ 9	$ 2

(a) 2013 amount includes (i) a $9 million increase in expense attributable to our drop-down asset group for periods prior to our acquisition date of March 1, 2013; (ii) a $4 million increase in expense associated with unallocated legal expenses and certain asset and business acquisition costs; and (iii) a $1 million increase in severance expense allocated to us from KMI (associated with both the asset drop-down group and assets we acquired from KMI in August 2012); however, we do not have any obligation, nor did we pay any amounts related to this expense. 2012 amount includes a $1 million increase in unallocated severance expense associated with certain Terminal operations.

(b) 2013 amount includes a $15 million increase in interest expense attributable to our drop-down asset group for periods prior to our acquisition date of March 1, 2013.

(c) 2013 and 2012 amounts include an increase of $2 million and a decrease of $4 million, respectively, in net income attributable to our noncontrolling interests, related to the combined effect from all of the 2013 and 2012 certain items previously disclosed in the footnotes to the tables included above in "—Results of Operations."

Items not attributable to any segment include general and administrative expenses, unallocable interest income and income tax expense, interest expense, and net income attributable to noncontrolling interests. Our general and administrative expenses include such items as unallocated salaries and employee-related expenses, employee benefits, payroll taxes, insurance, office supplies and rentals, unallocated litigation and environmental expenses, and shared corporate services—including accounting, information technology, human resources and legal services.

These expenses are generally not controllable by our business segment operating managers and therefore are not included when we measure business segment operating performance. For this reason and because we manage our business based on our reportable business segments and not on the basis of our ownership structure, we do not specifically allocate our general and administrative expenses to our business segments. As discussed previously, we use segment EBDA internally as a measure of profit and loss used for evaluating segment performance, and each of our segment's EBDA includes all costs directly incurred by that segment.

The certain items described in footnote (a) to the table above accounted for a $13 million increase in our general and administrative expenses in the first quarter of 2013, when compared to the same quarter a year ago. The remaining $14 million (13%) quarter-to-quarter increase in expense was driven by the acquisition of additional businesses, primarily associated with the acquisition of our Tennessee Gas Pipeline from KMI effective August 1, 2012, and partly associated with the acquisition of our drop-down asset group from KMI effective March 1, 2013.

We report our interest expense as "net," meaning that we have subtracted unallocated interest income and capitalized interest from our interest expense to arrive at one interest amount, and after taking into effect the certain item described in footnote (b) to the table above, our net interest expense increased by $48 million (35%) in the first quarter of 2013, when compared with the first quarter of 2012. The increase was driven by a 31% increase in our average debt balance for the first three months of 2013, versus the same year earlier period. Our higher average borrowings was largely due to the capital expenditures, business acquisitions (including debt assumed from the drop-down transaction), and joint venture contributions we have made since the end of the first quarter of 2012. We also realized an 8% increase in the weighted average interest rate on all of our borrowings in the first three months of 2013, when compared to the first quarter last year. Including both short-term and long-term borrowing amounts, our average interest rate increased from 4.23% for the first quarter of 2012 to 4.57% for the first quarter of 2013.

We swap a portion of our long-term fixed rate debt securities (senior notes) into variable rate debt in order to achieve our desired mix of fixed and variable rate debt. As of March 31, 2013 and December 31, 2012, approximately 35% and 37%, respectively, of our consolidated debt balances (excluding our debt fair value adjustments) was subject to variable interest rates—either as short-term or long-term variable rate debt obligations or as fixed-rate debt converted to variable rates through the use of interest rate swap agreements. For more information about our interest rate swaps, see Note 5 "Risk Management—Interest Rate Risk Management" to our consolidated financial statements included elsewhere in this report.

Financial Condition

General

As of March 31, 2013, we had $736 million of "Cash and cash equivalents" on our consolidated balance sheet (included elsewhere in this report), an increase of $207 million (39%) from December 31, 2012. We also had, as of March 31, 2013, approximately $1.4 billion of borrowing capacity available under our $2.2 billion senior unsecured revolving credit facility (discussed below in "—Short-term Liquidity"). We believe our cash position and our remaining borrowing capacity is adequate to allow us to manage our day-to-day cash requirements and anticipated obligations.

Our primary cash requirements, in addition to normal operating expenses, are for debt service, sustaining capital expenditures (defined as capital expenditures which do not increase the capacity of an asset), expansion capital expenditures and quarterly distributions to our common unitholders, Class B unitholder and general partner.

In general, we expect to fund:

- cash distributions and sustaining capital expenditures with existing cash and cash flows from operating activities;
- expansion capital expenditures and working capital deficits with retained cash (which may result from including i-units in the determination of cash distributions per unit but paying quarterly distributions on i-units in additional i-units rather than cash), additional borrowings (including commercial paper issuances), and the issuance of additional common units or the proceeds from purchases of additional i-units by KMR;
- interest payments with cash flows from operating activities; and
- debt principal payments, as such debt principal payments become due, with additional borrowings or by the issuance of additional common units or the proceeds from purchases of additional i-units by KMR.

In addition to our results of operations, our debt and capital balances are affected by our financing activities, as discussed below in "—Financing Activities."

Credit Ratings and Capital Market Liquidity

Currently, our long-term corporate debt credit rating is BBB (stable), Baa2 (stable) and BBB (stable), at Standard & Poor's Ratings Services, Moody's Investors Service, Inc. and Fitch, Inc., respectively. Our short-term corporate debt credit rating is A-2 (susceptible to adverse economic conditions, however, capacity to meet financial commitments is satisfactory), Prime-2 (strong ability to repay short-term debt obligations) and F2 (good quality grade with satisfactory capacity to meet financial commitments), at Standard & Poor's Ratings Services, Moody's Investors Service, Inc. and Fitch, Inc., respectively. Our credit ratings affect our ability to access the commercial paper market and the public and private debt markets, as well as the terms and pricing of our debt. Based on these credit ratings, we expect that our short-term liquidity needs will be met primarily through borrowings under our commercial paper program. Nevertheless, our ability to satisfy our financing requirements or fund our planned capital expenditures will depend upon our future operating performance, which will be affected by prevailing economic conditions in the energy pipeline and terminals industries and other financial and business factors, some of which are beyond our control.

Short-term Liquidity

As of March 31, 2013, our principal sources of short-term liquidity were (i) our $2.2 billion senior unsecured revolving credit facility with a diverse syndicate of banks that matures July 1, 2016; (ii) our $2.2 billion short-term commercial paper program (which is supported by our credit facility, with the amount available for borrowing under our credit facility being reduced by our outstanding commercial paper borrowings and letters of credit); and (iii) cash from operations (discussed below in "—Operating Activities"). The loan commitments under our revolving credit facility can be used to fund borrowings for general partnership purposes and as a backup for our commercial paper program, and our credit facility can be amended to allow for borrowings of up to $2.5 billion. As of both March 31, 2013 and December 31, 2012, we had no outstanding borrowings under our credit facility.

Our outstanding short-term debt as of March 31, 2013 was $1,127 million, primarily consisting of (i) $595 million of outstanding commercial paper borrowings; and (ii) $500 million in principal amount of 5.00% senior notes that mature December 15, 2013. We intend to refinance our current short-term debt through a combination of long-term debt, equity, and/or the issuance of additional commercial paper or credit facility borrowings to replace maturing commercial paper and current maturities of long-term debt. As of December 31, 2012, our short-term debt totaled $1,155 million.

We had a working capital deficit of $832 million as of March 31, 2013, and a working capital deficit of $870 million as of December 31, 2012. The overall $38 million (4%) favorable change from year-end 2012 was primarily due to the $207 million increase in "Cash and cash equivalents" described above in "—General," and partially offset by a $179 million decrease in working capital due to the removal of our equity and debt investments in the Express pipeline system from current assets held for sale (we sold our investments in Express in March 2013). Generally, our working capital balance varies due to factors such as the timing of scheduled debt payments, timing differences in the collection and payment of receivables and payables, the change in fair value of our derivative contracts, and changes in cash and cash equivalent balances as a result of debt or equity issuances (discussed below in "—Long-term Financing").

Long-term Financing

In addition to our principal sources of short-term liquidity listed above, we could meet our cash requirements (other than distributions of cash from operations to our common unitholders, Class B unitholder and general partner) through issuing long-term debt securities or additional common units, or by utilizing the proceeds from purchases of additional i-units by KMR with the proceeds from issuances of KMR shares.

Our equity offerings consist of the issuance of additional common units or the issuance of additional i-units to KMR (which KMR purchases with the proceeds from the sale of additional KMR shares). As a publicly traded limited partnership, our common units are attractive primarily to individual investors, although such investors represent a small segment of the total equity capital market. We believe that some institutional investors prefer shares of KMR over our common units due to tax and other regulatory considerations, and we are able to access this segment of the capital market through KMR's purchases of i-units issued by us with the proceeds from the sale of KMR shares to institutional investors. For more information about our equity issuances in the first three months of 2013, see Note 4 "Partners' Capital—Equity Issuances" to our consolidated financial statements included elsewhere in this report.

From time to time we issue long-term debt securities, often referred to as our senior notes. Our senior notes issued to date, other than those issued by our subsidiaries and operating partnerships, generally have very similar terms, except for interest rates, maturity dates and prepayment premiums. All of our outstanding senior notes are unsecured obligations that rank equally with all of our other senior debt obligations; however, a modest amount of secured debt has been incurred by some of our operating partnerships and subsidiaries. Our fixed rate senior notes provide that we may redeem the notes at any time at a price equal to 100% of the principal amount of the notes plus accrued interest to the redemption date plus a make-whole premium.

In addition, from time to time our subsidiaries Tennessee Gas Pipeline Company, L.L.C. and El Paso Natural Gas Company, L.L.C. have issued long-term debt securities, often referred to as their senior notes. As of March 31, 2013, Tennessee Gas Pipeline Company, L.L.C. is the obligor of six separate series of fixed-rate unsecured senior notes having a combined principal amount of $1,790 million. The interest rates on these notes range from 7% per annum through 8.375% per annum, and the maturity dates range from February 2016 through April 2037. El Paso Natural Gas Company, L.L.C. is the obligor of four separate series of fixed-rate unsecured senior notes having a combined principal amount of

$1,115 million. The interest rates on these notes range from 5.95% per annum through 8.625% per annum, and the maturity dates range from April 2017 through June 2032.

As of March 31, 2013 and December 31, 2012, the aggregate principal amount of the various series of our senior notes was $14,350 million and $13,350 million, respectively, and the total liability balance due on the various borrowings of our operating partnerships and subsidiaries (including both Tennessee Gas Pipeline Company, L.L.C.'s and El Paso Natural Gas Company, L.L.C.'s senior notes discussed above) was $3,011 million and $3,091 million, respectively. To date, our debt balances have not adversely affected our operations, our ability to grow or our ability to repay or refinance our indebtedness. For additional information about our debt related transactions in the first three months of 2013, see Note 3 "Debt" to our consolidated financial statements included elsewhere in this report. For additional information regarding our debt securities, see Note 15 "Reportable Segments" to our consolidated financial statements included in our 2012 Form 10-K.

Based on our historical record, we believe that our capital structure will continue to allow us to achieve our business objectives. We are subject, however, to conditions in the equity and debt markets for our limited partner units and long-term senior notes, and there can be no assurance we will be able or willing to access the public or private markets for our limited partner units and/or long-term senior notes in the future. If we were unable or unwilling to issue additional limited partner units, we would be required to either restrict expansion capital expenditures and/or potential future acquisitions or pursue debt financing alternatives, some of which could involve higher costs or negatively affect our credit ratings. Furthermore, our ability to access the public and private debt markets is affected by our credit ratings. See "—Credit Ratings and Capital Market Liquidity" above for a discussion of our credit ratings.

Capital Expenditures

We define sustaining capital expenditures as capital expenditures which do not increase the capacity of an asset and generally, we fund our sustaining capital expenditures with existing cash or from cash flows from operations. For the first three months of 2013 and 2012, our sustaining capital expenditures totaled $48 million and $44 million, respectively (the first quarter 2012 amount included $2 million for our proportionate share of the sustaining capital expenditures of our unconsolidated joint ventures). We forecasted $339 million for sustaining capital expenditures in our 2013 budget. This amount includes $6 million for our proportionate share of our unconsolidated joint ventures' sustaining capital expenditures.

In addition to the sustaining capital expenditures described above (excluding our proportionate share of the first quarter 2012 sustaining capital expenditures of our unconsolidated joint ventures), our consolidated statements of cash flows for the three months ended March 31, 2013 and 2012 included capital expenditures of $504 million and $311 million, respectively. We report our total consolidated capital expenditures separately as "Capital expenditures" within the "Cash Flows from Investing Activities" section on our accompanying cash flow statements (included elsewhere in this report), and the overall $199 million (56%) quarter-to-quarter increase in our consolidated capital expenditures in 2013 versus 2012 was primarily due to higher investment undertaken to expand and improve our Terminals, Natural Gas Pipelines, and CO_2 business segments. Generally, we initially fund our capital expenditures through borrowings under our commercial paper program or our revolving credit facility until the amount borrowed is of a sufficient size to cost effectively offer either debt, equity, or both.

Capital Requirements for Recent Drop-Down Transaction

In the first quarter of 2013, our cash outlays for the drop-down transaction totaled $988 million and we reported this amount separately as "Cash Flows From Investing Activities—Payment to KMI for drop-down asset group" on our accompanying consolidated statement of cash flows included elsewhere in this report. With the exception of our partial payment of the combined purchase price to KMI by the issuance of addition common units (discussed following), we funded this $988 million acquisition payment with proceeds received from (i) our February 2013 issuance of long-term senior notes; (ii) our February 2013 public offering of additional common units; and (iii) borrowings under our commercial paper program.

We also issued an aggregate consideration of $108 million in common units to KMI in the first quarter of 2013 as partial payment for the drop-down asset group. We reported this amount separately as "Noncash Investing and Financing

Activities—Assets acquired or liabilities settled by the issuance of common units" on our accompanying consolidated statement of cash flows included elsewhere in this report.

Additional Capital Requirements

In April 2012, we announced that we were proceeding with our proposal to expand our existing Trans Mountain pipeline system. When completed, the proposed expansion will increase capacity on Trans Mountain from its current 300,000 barrels per day of crude oil and refined petroleum products to approximately 890,000 barrels per day. In 2012, we confirmed binding commercial support for this project, and pending the filing and approval of tolling and facilities applications with Canada's National Energy Board (NEB), we expect to begin construction in 2015 or 2016, with the proposed project beginning operations in late 2017. Our current estimate of total construction costs on the project is approximately $5.4 billion. Trans Mountain is currently in the final stages of securing NEB approval for the commercial terms of the expansion. Failure to secure NEB approval of this project at a reasonable toll rate could require us to either delay or cancel this project. We anticipate NEB's approval in the second quarter of 2013.

In addition, we regularly consider and enter into discussions regarding potential acquisitions, including those from KMI or its affiliates, and are currently contemplating potential acquisitions. Such transactions can be effected quickly, may occur at any time and may be significant in size relative to our existing assets or operations. For the year 2013, we expect to invest over $3 billion for our capital expansion program, which includes small acquisitions and contributions to joint ventures, but excludes acquisitions from KMI. Our previously announced acquisition of Copano will be a 100% unit for unit transaction. For more information about our asset acquisitions from KMI and our announced acquisition of Copano, see Note 2 "Acquisitions and Divestitures" to our consolidated financial statements included elsewhere in this report.

Our ability to make accretive acquisitions (i) is a function of the availability of suitable acquisition candidates at the right cost; (ii) is impacted by our ability to maintain adequate liquidity and to raise the necessary capital needed to fund such acquisitions; and (iii) includes factors over which we have limited or no control. Thus, we have no way to determine the number or size of accretive acquisition candidates in the future, or whether we will complete the acquisition of any such candidates. Our ability to expand our assets is also impacted by our ability to maintain adequate liquidity and to raise the necessary capital needed to fund such expansions.

As a master limited partnership, we distribute all of our available cash (except to the extent that we retain cash from the payment of distributions on i-units in additional i-units) and we access capital markets to fund acquisitions and asset expansions. Historically, we have succeeded in raising necessary capital in order to fund our acquisitions and expansions, and although we cannot predict future changes in the overall equity and debt capital markets (in terms of tightening or loosening of credit), we believe that our stable cash flows, our investment grade credit rating, and our historical record of successfully accessing both equity and debt funding sources should allow us to continue to execute our current investment, distribution and acquisition strategies, as well as refinance maturing debt when required.

Operating Activities

Net cash provided by operating activities was $746 million for the three months ended March 31, 2013, versus $658 million for the same comparable period of 2012. The quarter-to-quarter increase of $88 million (13%) in cash flow from operations was due to the following:

- a $136 million increase in cash from overall higher partnership income—after adjusting our quarter-to-quarter $584 million increase in net income for the following four non-cash items: (i) a $320 million decrease from lower losses from both the sale and the remeasurement of our FTC Natural Gas Pipelines disposal group's net assets to fair value; (ii) a $225 million decrease from the first quarter 2013 gain on the sale of our investments in Express (we reported the proceeds received from this sale within the operating activities section of our statement of cash flows); (iii) an $82 million increase due to higher depreciation, depletion and amortization expenses (including amortization of excess cost of equity investments); and (iv) a $15 million increase related to a non-cash legal expense recorded in the first quarter of 2013, associated with a certain environmental matter related to our West Coast terminal operations.

  The quarter-to-quarter change in partnership income in 2013 versus 2012 is discussed above in "—Results of Operations" (including all of the certain items disclosed in the associated table footnotes). The sale and remeasurement of our FTC Natural Gas Pipelines disposal group and the sale of our investments in Express are all discussed further in Note 2 “Acquisitions and Divestitures—Divestitures” to our consolidated financial statements included elsewhere in this report; and

- a combined $48 million decrease in cash related to net changes in working capital items, non-current assets and liabilities, and other non-cash income and expense items. The overall decrease related primarily to the following four items: (i) a $91 million decrease in cash due to unfavorable changes in the collection and payment of trade and related party receivables and payables; (ii) a $71 million decrease in cash from net changes in cash book overdrafts, resulting from timing differences on checks issued but not yet presented for payment; (iii) a $64 million increase in cash due to lower expenditures for inventories, primarily due to higher payments made in the first quarter of 2012 for short-term liquids transmix inventories; and (iv) a $53 million increase in cash due to favorable changes in current income tax liabilities, due mainly to incremental income tax liabilities related to our sale of Express that have not yet been paid.

Investing Activities

Net cash used in investing activities was $1,171 million for the three month period ended March 31, 2013, compared to $373 million in the comparable 2012 period. The overall $798 million (214%) decrease in cash from investing activities primarily consisted of the following:

- a $988 million decrease from our cash outlay as partial payment for the drop-down asset group in March 2013, as described above in “—Capital Requirements for Recent Drop-Down Transaction;”

- a $199 million decrease in cash due to higher capital expenditures, as described above in “—Capital Expenditures;”

- a $403 million increase from the proceeds we received in March 2013 from the sale of our investments in the Express pipeline system.

Financing Activities

Net cash provided by financing activities amounted to $638 million for the three months ended March 31, 2013. In the comparable prior year period, we used $210 million in cash from financing activities. The $848 million (404%) overall increase in cash from the comparable 2012 period was mainly due to the following:

- a $629 million increase in cash from overall debt financing activities—which include our issuances and payments of debt and our debt issuance costs. This increase in cash was primarily due to (i) a combined $447 million increase due to higher net issuances of our senior notes (in the first quarter of 2013, we generated proceeds of $991 million from the issuance of senior notes, and in the first quarter of 2012, we generated net cash proceeds of $544 million from both issuing and repaying senior notes); (ii) a $261 million increase due to lower short-term net repayments on borrowings made under our commercial paper program; and (iii) a $78 million decrease related to the net repayment of all of the outstanding borrowings under the midstream assets’ bank credit facility that we assumed on our March 1, 2013 acquisition date;

- a $261 million increase in cash due to higher partnership equity issuances. This increase reflects the $385 million we received, after commissions and underwriting expenses, from the sales of additional common units in the first three months of 2013 (discussed in Note 4 “Partners’ Capital—Equity Issuances” to our consolidated financial statements included elsewhere in this report), versus the $124 million we received from the sales of additional common units in the first quarter a year ago;

- a $63 million increase in cash due to higher net contributions from noncontrolling interests, chiefly due to the $59 million of contributions we received from our Battleground Oil Specialty Terminal Company LLC (BOSTCO) partners in the first quarter of 2013; and

- a $140 million decrease in cash due to higher partnership distributions. Distributions to all partners, consisting of our common and Class B unitholders, our general partner and our noncontrolling interests, totaled $730 million in the first quarter of 2013. In the comparable quarter of 2012, we distributed $590 million to our partners. Further information regarding our distributions is discussed following in "—Partnership Distributions."

Partnership Distributions

Our partnership agreement requires that we distribute 100% of "Available Cash," as defined in our partnership agreement, to our partners within 45 days following the end of each calendar quarter. Our 2012 Form 10-K contains additional information concerning our partnership distributions, including the definition of "Available Cash," the manner in which our total distributions are divided between our general partner and our limited partners, and the form of distributions to all of our partners, including our noncontrolling interests. For further information about the partnership distributions we paid in the first quarters of 2013 and 2012 (for the fourth quarterly periods of 2012 and 2011, respectively), see Note 4 "Partners' Capital—Income Allocation and Declared Distributions" to our consolidated financial statements included elsewhere in this report.

Furthermore, on April 17, 2013, we declared a cash distribution of $1.30 per unit for the first quarter of 2013 (an annualized rate of $5.20 per unit). This distribution is 8% higher than the $1.20 per unit distribution we made for the first quarter of 2012. Our declared distribution for the first quarter of 2013 of $1.30 per unit will result in an incentive distribution to our general partner of $398 million (including the effect of a waived incentive distribution amount of $4 million related to our July 2011 KinderHawk acquisition). Comparatively, our distribution of $1.20 per unit paid on May 15, 2012 for the first quarter of 2012 resulted in an incentive distribution payment to our general partner in the amount of $319 million (and included the effect of a waived incentive distribution amount of $6 million related to our July 2011 KinderHawk acquisition). The increased incentive distribution to our general partner for the first quarter of 2013 over the incentive distribution for the first quarter of 2012 reflects the increase in the distribution per unit as well as the issuance of additional units. For additional information about our first quarter 2013 cash distribution, see Note 4 "Partners' Capital—Subsequent Events" to our consolidated financial statements included elsewhere in this report. For additional information about our 2012 partnership distributions, see Note 16 "Litigation, Environmental and Other Contingencies" and Note 17 "Regulatory Matters" to our consolidated financial statements included in our 2012 Form 10-K.

Currently, we expect to declare cash distributions of $5.28 per unit for 2013, a 6% increase over our cash distributions of $4.98 per unit for 2012. Furthermore, we expect our acquisition of Copano to be accretive to cash available for distribution to our unitholders upon closing. Our general partner has agreed to forego a portion of its incremental incentive distributions in 2013 in an amount dependent on the time of closing. Additionally, our general partner intends to forgo incentive distribution amounts of $120 million in 2014, $120 million in 2015, $110 million in 2016, and annual amounts thereafter decreasing by $5 million per year from this level. We expect the Copano acquisition to be modestly accretive to us in 2013, given the partial year, and about $0.10 per unit accretive for at least the next five years beginning in 2014.

Although the majority of the cash generated by our assets is fee based and is not sensitive to commodity prices, our CO_2 business segment is exposed to commodity price risk related to the price volatility of crude oil and natural gas liquids, and while we hedge the majority of our crude oil production, we do have exposure on our unhedged volumes, the majority of which are natural gas liquids volumes. Our 2013 budget assumes an average West Texas Intermediate (WTI) crude oil price of approximately $91.68 per barrel (with some minor adjustments for timing, quality and location differences) in 2013, and based on the actual prices we have received through the date of this report and the forward price curve for WTI (adjusted for the same factors used in our 2013 budget), we currently expect the average price of WTI crude oil will be approximately $93.89 per barrel in 2013. For 2013, we expect that every $1 change in the average WTI crude oil price per barrel will impact our CO_2 segment's cash flows by approximately $6 million (or approximately 0.1% of our combined business segments' anticipated earnings before depreciation, depletion and amortization expenses). This sensitivity to the average WTI price is very similar to what we experienced in 2012.

Off Balance Sheet Arrangements

There have been no material changes in our obligations with respect to other entities that are not consolidated in our financial statements that would affect the disclosures presented as of December 31, 2012 in our 2012 Form 10-K.

Recent Accounting Pronouncements

Please refer to Note 11 “Recent Accounting Pronouncements” to our consolidated financial statements included elsewhere in this report for information concerning recent accounting pronouncements.

Information Regarding Forward-Looking Statements

This report includes forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. They use words such as “anticipate,” “believe,” “intend,” “plan,” “projection,” “forecast,” “strategy,” “position,” “continue,” “estimate,” “expect,” “may,” or the negative of those terms or other variations of them or comparable terminology. In particular, statements, express or implied, concerning future actions, conditions or events, future operating results or the ability to generate sales, income or cash flow or to make distributions are forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability to control or predict.

See Part I, Item 1A “Risk Factors” and Part II, Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Information Regarding Forward-Looking Statements” of our 2012 Form 10-K for a more detailed description of factors that may affect the forward-looking statements. When considering forward-looking statements, one should keep in mind the risk factors described in our 2012 Form 10-K. The risk factors could cause our actual results to differ materially from those contained in any forward-looking statement. We disclaim any obligation, other than as required by applicable law, to update any forward-looking statements to reflect future events or developments after the date of this report.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

There have been no material changes in market risk exposures that would affect the quantitative and qualitative disclosures presented as of December 31, 2012, in Item 7A of our 2012 Form 10-K. For more information on our risk management activities, see Note 5 “Risk Management” to our consolidated financial statements included elsewhere in this report.

Item 4. Controls and Procedures.

As of March 31, 2013, our management, including our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15 (b) under the Securities Exchange Act of 1934. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Based upon and as of the date of the evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that the design and operation of our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed in the reports we file and submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported as and when required, and is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. There has been no change in our internal control over financial reporting during the quarter ended March 31, 2013 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

See Part I, Item 1, Note 9 to our consolidated financial statements entitled "Litigation, Environmental and Other Contingencies," which is incorporated in this item by reference.

Item 1A. Risk Factors.

There have been no material changes in or additions to the risk factors disclosed in Part I, Item 1A "Risk Factors" in our 2012 Form 10-K.

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

On March 1, 2013, we paid to KMI $988 million in cash, issued 1,249,452 common units, and assumed $557 million in debt for the acquisition of certain natural gas pipeline assets. We valued the common units at $108 million, determining the units' value based on the $86.72 closing market price of a common unit on the New York Stock Exchange on the March 1, 2013 issuance date. The units were issued to KMI pursuant to Section 4(2) of the Securities Act of 1933.

Item 3. Defaults Upon Senior Securities.

None.

Item 4. Mine Safety Disclosures

The information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.104) is included in exhibit 95 to this quarterly report.

Item 5. Other Information.

None.

Item 6. Exhibits.

*2.1	—	Agreement and Plan of Merger, dated as of January 29, 2013, by and among Kinder Morgan Energy Partners, L.P., Kinder Morgan, G.P., Inc, Javelina Merger Sub LLC and Copano Energy, L.L.C. (filed as Exhibit 2.1 to Kinder Morgan Energy Partners, L.P.'s Current Report on Form 8-K filed on February 4, 2013 and incorporated herein by reference).
3.1	—	Amendment No. 5 to Third Amended and Restated Agreement of Limited Partnership of Kinder Morgan Energy Partners, L.P.
4.1	—	Certificate of the Vice President and Chief Financial Officer and the Vice President, General Counsel and Secretary of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 3.50% Senior Notes due September 1, 2023, and the 5.00% Senior Notes due March 1, 2043.
4.2	—	Certain instruments with respect to long-term debt of Kinder Morgan Energy Partners, L.P. and its consolidated subsidiaries which relate to debt that does not exceed 10% of the total assets of Kinder Morgan Energy Partners, L.P. and its consolidated subsidiaries are omitted pursuant to Item 601(b) (4)(iii) (A) of Regulation S-K (17 CFR 229.601). Kinder Morgan Energy Partners, L.P. hereby agrees to furnish supplementally to the Securities and Exchange Commission a copy of each such instrument upon request.
*10.1	—	Voting Agreement, dated as of January 29, 2013, by and among Kinder Morgan Energy Partners, L.P., Kinder Morgan G.P., Inc., Copano Energy, L.L.C. and TPG Copenhagen, L.P. (filed as Exhibit 10.1 to Kinder Morgan Energy Partners, L.P.'s Current Report on Form 8-K filed on February 4, 2013 and incorporated herein by reference).
11	—	Statement re: computation of per share earnings.
12	—	Statement re: computation of ratio of earnings to fixed charges.
31.1	—	Certification by CEO pursuant to Rule 13a-14 or 15d-14 of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	—	Certification by CFO pursuant to Rule 13a-14 or 15d-14 of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	—	Certification by CEO pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	—	Certification by CFO pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
95	—	Mine Safety Disclosures.
101	—	Interactive data files pursuant to Rule 405 of Regulation S-T: (i) our Consolidated Statements of Income for the three months ended March 31, 2013 and 2012; (ii) our Consolidated Statements of Comprehensive Income for the three months ended March 31, 2013 and 2012; (iii) our Consolidated Balance Sheets as of March 31, 2013 and December 31, 2012; (iv) our Consolidated Statements of Cash Flows for the three months ended March 31, 2013 and 2012; and (v) the notes to our Consolidated Financial Statements.

* Asterisk indicates exhibit incorporated by reference as indicated; all other exhibits are filed herewith, except as noted otherwise.

SIGNATURE

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

KINDER MORGAN ENERGY PARTNERS, L.P.
Registrant (a Delaware limited partnership)

By: **KINDER MORGAN G.P., INC.,**
its sole General Partner

By: **KINDER MORGAN MANAGEMENT, LLC,**
the Delegate of Kinder Morgan G.P., Inc.

Date: April 29, 2013

By: /s/ Kimberly A. Dang
Kimberly A. Dang
Vice President and Chief Financial Officer
(principal financial and accounting officer)