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 **June 30, 2011**

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.)

500 Dallas 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 229,289,810 common units outstanding as of July 29, 2011.

KINDER MORGAN ENERGY PARTNERS, L.P. AND SUBSIDIARIES
TABLE OF CONTENTS

		Page Number
	PART I. FINANCIAL INFORMATION	
Item 1.	Financial Statements (Unaudited)	3
	Consolidated Statements of Income - Three and Six Months Ended June 30, 2011 and 2010	3
	Consolidated Balance Sheets – June 30, 2011 and December 31, 2010	4
	Consolidated Statements of Cash Flows – Six Months Ended June 30, 2011 and 2010	5
	Notes to Consolidated Financial Statements	6
Item 2.	Management's Discussion and Analysis of Financial Condition and Results of Operations	41
	General and Basis of Presentation	41
	Critical Accounting Policies and Estimates	43
	Results of Operations	44
	Financial Condition	59
	Recent Accounting Pronouncements	65
	Information Regarding Forward-Looking Statements	65
Item 3.	Quantitative and Qualitative Disclosures About Market Risk	67
Item 4.	Controls and Procedures	67
	PART II. OTHER INFORMATION	
Item 1.	Legal Proceedings	68
Item 1A.	Risk Factors	68
Item 2.	Unregistered Sales of Equity Securities and Use of Proceeds	68
Item 3.	Defaults Upon Senior Securities	68
Item 4.	(Removed and Reserved)	68
Item 5.	Other Information	68
Item 6.	Exhibits	68
	Signature	70

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 June 30,		Six Months Ended June 30,	
	2011	**2010**	**2011**	**2010**
Revenues				
Natural gas sales	$ 850.0	$ 848.1	$ 1,656.0	$ 1,865.6
Services	753.1	751.7	1,537.5	1,490.2
Product sales and other	416.2	361.7	818.6	735.3
Total Revenues	2,019.3	1,961.5	4,012.1	4,091.1
Operating Costs, Expenses and Other				
Gas purchases and other costs of sales	883.3	848.0	1,699.0	1,864.6
Operations and maintenance	479.5	317.5	788.1	770.4
Depreciation, depletion and amortization	229.4	223.2	451.2	450.5
General and administrative	97.4	93.4	286.6	194.5
Taxes, other than income taxes	53.3	41.1	101.9	86.2
Other expense (income)	(13.8)	(5.3)	(14.0)	(6.6)
Total Operating Costs, Expenses and Other	1,729.1	1,517.9	3,312.8	3,359.6
Operating Income	290.2	443.6	699.3	731.5
Other Income (Expense)				
Earnings from equity investments	76.4	55.2	141.3	101.9
Amortization of excess cost of equity investments	(1.6)	(1.5)	(3.1)	(2.9)
Interest expense	(130.2)	(123.9)	(262.2)	(240.9)
Interest income	5.8	7.0	11.1	12.5
Other, net	6.4	(2.3)	8.0	4.4
Total Other Income (Expense)	(43.2)	(65.5)	(104.9)	(125.0)
Income Before Income Taxes	247.0	378.1	594.4	606.5
Income Tax (Expense) Benefit	(15.1)	(13.0)	(21.6)	(14.0)
Net Income	231.9	365.1	572.8	592.5
Net Income Attributable to Noncontrolling Interests	(1.4)	(3.9)	(4.5)	(6.0)
Net Income Attributable to Kinder Morgan Energy Partners, L.P.	$ 230.5	$ 361.2	$ 568.3	$ 586.5
Calculation of Limited Partners' Interest in Net Income (Loss) Attributable to Kinder Morgan Energy Partners, L.P.:				
Net Income Attributable to Kinder Morgan Energy Partners, L.P.	$ 230.5	$ 361.2	$ 568.3	$ 586.5
Less: General Partner's Interest	(292.2)	(92.5)	(572.8)	(341.7)
Limited Partners' Interest in Net Income (Loss)	$ (61.7)	$ 268.7	$ (4.5)	$ 244.8
Limited Partners' Net Income (Loss) per Unit	$ (0.19)	$ 0.88	$ (0.01)	$ 0.81
Weighted Average Number of Units Used in Computation of Limited Partners' Net Income per Unit	321.4	304.5	319.3	301.7
Per Unit Cash Distribution Declared	$ 1.15	$ 1.09	$ 2.29	$ 2.16

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)

	June 30, 2011 (Unaudited)	December 31, 2010
ASSETS		
Current assets		
Cash and cash equivalents	$ 352.6	$ 129.1
Restricted deposits	-	50.0
Accounts, notes and interest receivable, net	899.1	951.8
Inventories	80.8	92.0
Gas in underground storage	68.9	2.2
Fair value of derivative contracts	39.8	24.0
Other current assets	49.3	37.6
Total current assets	1,490.5	1,286.7
Property, plant and equipment, net	14,823.6	14,603.9
Investments	3,907.6	3,886.0
Notes receivable	122.2	115.0
Goodwill	1,230.8	1,233.6
Other intangibles, net	306.0	302.2
Fair value of derivative contracts	292.3	260.7
Deferred charges and other assets	168.7	173.0
Total Assets	$ 22,341.7	$ 21,861.1
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Current portion of debt	$ 991.3	$ 1,262.4
Cash book overdrafts	19.2	32.5
Accounts payable	652.4	630.9
Accrued interest	243.9	239.6
Accrued taxes	74.7	44.7
Deferred revenues	96.1	96.6
Fair value of derivative contracts	209.1	281.5
Accrued other current liabilities	195.7	176.0
Total current liabilities	2,482.4	2,764.2
Long-term liabilities and deferred credits		
Long-term debt		
Outstanding	10,415.6	10,277.4
Value of interest rate swaps	648.0	604.9
Total Long-term debt	11,063.6	10,882.3
Deferred income taxes	251.1	248.3
Fair value of derivative contracts	184.5	172.2
Other long-term liabilities and deferred credits	656.2	501.6
Total long-term liabilities and deferred credits	12,155.4	11,804.4
Total Liabilities	14,637.8	14,568.6
Commitments and contingencies (Notes 4 and 10)		
Partners' Capital		
Common units	4,571.9	4,282.2
Class B units	52.5	63.1
i-units	2,832.4	2,807.5
General partner	256.2	244.3
Accumulated other comprehensive loss	(96.8)	(186.4)
Total Kinder Morgan Energy Partners, L.P. partners' capital	7,616.2	7,210.7
Noncontrolling interests	87.7	81.8
Total Partners' Capital	7,703.9	7,292.5
Total Liabilities and Partners' Capital	$ 22,341.7	$ 21,861.1

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
(In Millions) (Unaudited)

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Cash Flows From Operating Activities		
Net Income	$ 572.8	$ 592.5
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	451.2	450.5
Amortization of excess cost of equity investments	3.1	2.9
Noncash compensation expense allocated from parent (Note 9)	89.9	2.7
Earnings from equity investments	(141.3)	(101.9)
Distributions from equity investments	135.7	101.9
Changes in components of working capital:		
Accounts receivable	55.0	62.9
Inventories	12.1	(29.7)
Other current assets	(71.0)	(20.8)
Accounts payable	14.8	(42.7)
Accrued interest	4.3	10.3
Accrued taxes	18.9	(2.2)
Accrued liabilities	(9.8)	(13.0)
Rate reparations, refunds and other litigation reserve adjustments	102.0	(48.3)
Other, net	14.3	(32.9)
Net Cash Provided by Operating Activities	1,252.0	932.2
Cash Flows From Investing Activities		
Acquisitions of investments	(65.9)	(929.7)
Acquisitions of assets	(44.1)	(218.1)
Capital expenditures	(535.4)	(451.1)
Sale or casualty of property, plant and equipment, and other net assets net of removal costs	16.6	22.5
Net proceeds from (Investments in) margin and restricted deposits	48.9	(3.9)
Contributions to equity investments	(60.1)	(180.9)
Distributions from equity investments in excess of cumulative earnings	121.2	93.3
Other, net	0.1	-
Net Cash Used in Investing Activities	(518.7)	(1,667.9)
Cash Flows From Financing Activities		
Issuance of debt	3,514.6	4,709.5
Payment of debt	(3,641.3)	(3,443.0)
Repayments from related party	1.4	1.3
Debt issue costs	(7.5)	(22.3)
(Decrease) Increase in cash book overdrafts	(13.2)	8.1
Proceeds from issuance of common units	705.8	433.2
Contributions from noncontrolling interests	13.1	7.2
Distributions to partners and noncontrolling interests:		
Common units	(498.4)	(439.5)
Class B units	(12.1)	(11.3)
General Partner	(561.8)	(498.2)
Noncontrolling interests	(13.5)	(12.0)
Other, net	0.1	-
Net Cash (Used in) Provided by Financing Activities	(512.8)	733.0
Effect of Exchange Rate Changes on Cash and Cash Equivalents	3.0	(0.8)
Net increase (decrease) in Cash and Cash Equivalents	223.5	(3.5)
Cash and Cash Equivalents, beginning of period	129.1	146.6
Cash and Cash Equivalents, end of period	$ 352.6	$ 143.1
Noncash Investing and Financing Activities		
Assets acquired by the assumption or incurrence of liabilities	$ 9.7	$ 8.1
Assets acquired by the issuance of common units	$ 23.7	$ 81.7
Contribution of net assets to investments	$ 7.9	$ -
Sale of investment ownership interest in exchange for note	$ 4.1	$ -
Supplemental Disclosures of Cash Flow Information		
Cash paid during the period for interest (net of capitalized interest)	$ 260.8	$ 224.7
Cash paid during the period for income taxes	$ 9.5	$ 7.9

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. and its consolidated subsidiaries. We own an interest in or operate approximately 28,000 miles of pipelines and 180 terminals, and conduct our business through five reportable business segments (described further in Note 8). 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 bulk materials such as coal and petroleum coke. We are also the leading provider of carbon dioxide for enhanced oil recovery projects in North America. Our general partner is owned by Kinder Morgan, Inc., as discussed below.

Kinder Morgan, Inc., Kinder Morgan Kansas, 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 Kinder Morgan Kansas, Inc. Kinder Morgan Kansas, Inc. is a Kansas corporation and 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 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. As of June 30, 2011, KMI and its consolidated subsidiaries owned, through KMI's general and limited partner interests in us and its ownership of shares issued by its subsidiary Kinder Morgan Management, LLC (discussed following), an approximate 12.5% interest in us.

KMI was formed August 23, 2006 as a Delaware limited liability company principally for the purpose of acquiring (through a wholly-owned subsidiary) all of the common stock of Kinder Morgan Kansas, Inc. The merger, referred to in this report as the going-private transaction, closed on May 30, 2007 with Kinder Morgan Kansas, Inc. continuing as the surviving legal entity.

On February 10, 2011, KMI converted from a Delaware limited liability company named Kinder Morgan Holdco LLC to a Delaware corporation named Kinder Morgan, Inc., and its outstanding units were converted into classes of capital stock. On February 16, 2011, KMI completed the initial public offering of its common stock. All of the common stock that was sold in the offering was sold by existing investors, consisting of funds advised by or affiliated with Goldman, Sachs & Co., Highstar Capital LP, The Carlyle Group and Riverstone Holdings LLC. No members of management sold shares in the offering and KMI did not receive any proceeds from the offering. KMI's common stock trades on the New York Stock Exchange under the symbol "KMI."

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 represent limited liability company interests and trade on the New York Stock Exchange under the symbol "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, 2010. In this report, we refer to our Annual Report on Form 10-K for the year ended December 31, 2010 as our 2010 Form 10-K, and we refer to our Amended Annual Report on Form 10-K for the year ended December 31, 2010, as our 2010 Form 10-K/A. The sole purpose of our amended filing was to include the signature line of the Report of Independent Registered Public Accounting Firm included in our original filing's Item 8 "Financial Statements and Supplementary Data."

Basis of Presentation

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, the single source of generally accepted accounting principles in the United States of America and referred to in this report as the 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.

In addition, our 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 2010 Form 10-K/A.

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.

In addition, our financial statements are consolidated into the consolidated financial statements of KMI; however, except for the related party transactions described in Note 9 "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.

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. The overall computation, presentation, and disclosure requirements for our Limited Partners' Net Income (Loss) per Unit are made in accordance with the "Earnings per Share" Topic of the Codification.

2. Acquisitions and Divestitures

Acquisitions

Watco Companies, LLC

On January 3, 2011, we purchased 50,000 Class A preferred shares of Watco Companies, LLC for $50.0 million in cash in a private transaction. In connection with our purchase of these preferred shares, the most senior equity security of Watco, we entered into a limited liability company agreement with Watco that provides us certain priority and participating cash distribution and liquidation rights. Pursuant to the agreement, we receive priority, cumulative cash distributions from the preferred shares at a rate of 3.25% per quarter, and we participate partially in additional profit distributions at a rate equal to 0.5%. The preferred shares have no conversion features and hold no voting powers, but do provide us certain approval rights, including the right to appoint one of the members to Watco's Board of Managers. As of December 31, 2010, we placed our $50.0 million investment in a cash escrow account and we included this amount within "Restricted Deposits" on our accompanying consolidated balance sheet. As of June 30, 2011, our net equity investment in Watco totaled $51.6 million and is included within "Investments" on our accompanying consolidated balance sheet. We account for our investment under the equity method of accounting, and we include it in our Terminals business segment.

Watco Companies, LLC is a privately owned, Pittsburg, Kansas based transportation company that was formed in 1983. It is the largest privately held short line railroad company in the United States, operating 22 short line railroads on approximately 3,500 miles of leased and owned track. It also operates transload/intermodal and mechanical services divisions. Our investment provides capital to Watco for further expansion of specific projects, complements our existing terminal network, provides our customers more transportation services for many of the commodities that we currently handle, and offers us the opportunity to share in additional growth opportunities through new projects.

Deeprock North, LLC

On February 17, 2011, Deeprock Energy Resources, LLC, Mecuria Energy Trading, Inc., and our subsidiary Kinder Morgan Cushing LLC, entered into formal agreements for a crude oil storage joint venture located in Cushing, Oklahoma. On this date, we contributed $15.9 million for a 50% ownership interest in an existing crude oil tank farm that has storage capacity of one million barrels, and we expect to invest an additional $8.8 million for the construction of three new storage tanks that will provide incremental storage capacity of 750,000 barrels. The new tanks are expected to be placed in service during the fourth quarter of 2011. The joint venture is named Deeprock North, LLC. Deeprock Energy owns a 12.02% member interest in Deeprock North, LLC and will remain construction manager and operator of the joint venture. Mecuria owns the remaining 37.98% member interest and will remain the anchor tenant for the joint venture's crude oil capacity for the next five years with an option to extend. In addition, we entered into a development agreement with Deeprock Energy that gives us an option to participate in future expansions on Deeprock's remaining 254 acres of undeveloped land.

We account for our investment under the equity method of accounting, and our investment and our pro rata share of Deeprock North LLC's operating results are included as part of our Terminals business segment. As of June 30, 2011, our net equity investment in Deeprock North, LLC totaled $20.6 million and is included within "Investments" on our accompanying consolidated balance sheet.

TGS Development, L.P. Terminal Acquisition

On June 10, 2011, we acquired a newly constructed petroleum coke terminal located in Port Arthur, Texas from TGS Development, L.P. (TGSD) for an aggregate consideration of $74.1 million, consisting of $42.9 million in cash, $23.7 million in common units, and an obligation to pay additional consideration of $7.5 million. We estimate our remaining $7.5 million obligation will be paid to TGSD approximately one year from the closing (in May or June 2012), and will be settled in a combination of cash and common units, depending on TGSD's election.

All of the acquired assets are located in Port Arthur, Texas, and include long-term contracts to provide petroleum coke handling and cutting services to improve the refining of heavy crude oil at Total Petrochemicals USA Inc.'s recently expanded Port Arthur refinery. The refinery is expected to produce more than one million tons of petroleum coke annually. Based on our measurement of fair values for all of the identifiable tangible and intangible assets acquired, we preliminarily assigned $42.6 million of our combined purchase price to "Property, plant and equipment, net," and the remaining $31.5 million to "Other Intangibles, net," representing the combined fair values of two separate intangible customer contracts with Total. The acquisition complements our existing Gulf Coast bulk terminal facilities and expands our pre-existing petroleum coke handling operations. All of the acquired assets are included as part of our Terminals business segment.

Pro Forma Information

Pro forma consolidated income statement information that gives effect to all of the acquisitions we have made and all of the joint ventures we have entered into since January 1, 2010 as if they had occurred as of January 1, 2010 is not presented because it would not be materially different from the information presented in our accompanying consolidated statements of income.

Acquisitions Subsequent to June 30, 2011

Effective July 1, 2011, we acquired from Petrohawk Energy Corporation both the remaining 50% equity ownership interest in KinderHawk Field Services LLC that we did not already own and a 25% equity ownership interest in Petrohawk's natural gas gathering and treating business located in the Eagle Ford shale formation in South Texas for an aggregate consideration of $911.9 million, consisting of $834.9 million in cash (consisting of $836.2 million in cash paid, offset by $1.3 million in cash acquired) and assumed debt of $77.0 million. We then repaid the outstanding $154.0 million of borrowings under KinderHawk's bank credit facility, and following this repayment, KinderHawk had no outstanding debt.

KinderHawk Field Services LLC owns and operates the largest natural gas gathering and midstream business in the Haynesville shale formation located in northwest Louisiana, consisting of more than 400 miles of pipeline with over 2.0 billion cubic feet per day of pipeline capacity. Currently, it gathers approximately 1.0 billion cubic feet of natural gas per day; however, it is expected to gather approximately 1.2 billion cubic feet per day by the end of 2011. We operate KinderHawk Field Services LLC, and we acquired our original 50% ownership interest in KinderHawk Field Services LLC on May 21, 2010.

Following our acquisition of the remaining ownership interest on July 1, 2011, we made the change in accounting for our investment from the equity method to full consolidation. In the third quarter of 2011, we will measure the identifiable tangible and intangible assets and liabilities assumed at fair value on the acquisition date and, based on our expected measurement of fair values and the consideration we transferred to Petrohawk for our remaining 50% ownership interest (discussed above), we expect to recognize an approximate $170 million non-cash loss related to the remeasurement of our previously held 50% equity interest in KinderHawk to fair value.

The Eagle Ford natural gas gathering joint venture is named EagleHawk Field Services LLC, and we will account for our 25% investment under the equity method of accounting. Petrohawk will operate EagleHawk Field Services LLC and will own the remaining 75% ownership interest. The joint venture will own two midstream gathering systems in and around Petrohawk's Hawkville and Black Hawk areas of Eagle Ford and combined, the joint venture's assets will consist of more than 280 miles of gas gathering pipelines and approximately 140 miles of condensate lines to be in service by the end of 2011. It will also have a life of lease dedication of Petrohawk's Eagle Ford reserves that will provide Petrohawk and other Eagle Ford producers with gas and condensate gathering, treating and condensate stabilization services.

The acquisition of the remaining ownership interest in KinderHawk and the equity ownership interest in EagleHawk complements and expands our existing natural gas gathering operations, and all of the acquired assets will be included in our Natural Gas Pipelines business segment. Additionally, on July 14, 2011, mining and oil company BHP Billiton and Petrohawk Energy Corporation announced that the companies have entered into a definitive agreement for BHP Billiton to acquire Petrohawk by means of an all-cash tender offer for all of the issued and outstanding shares of Petrohawk. If the transaction closes, the terms of our contracts with Petrohawk would not be affected.

Divestitures

Megafleet Towing Co., Inc. Assets

On February 9, 2011, we sold a marine vessel to Kirby Inland Marine, L.P., and additionally, we and Kirby formed a joint venture named Greens Bayou Fleeting, LLC. Pursuant to the joint venture agreement, we sold our ownership interest in the boat fleeting business we acquired from Megafleet Towing Co., Inc. in April 2009 to the joint venture for $4.1 million in cash and a 49% ownership interest in the joint venture. Kirby then made cash contributions to the joint venture in exchange for the remaining 51% ownership interest. Related to the above transactions, we recorded a loss of $5.5 million ($4.1 million after tax) in the fourth quarter of 2010 to write down the carrying value of the net assets to be sold to their estimated fair values as of December 31, 2010.

In the first quarter of 2011, after final reconciliation and measurement of all of the net assets sold, we recognized a combined $2.2 million increase in income from the sale of these net assets, primarily consisting of a $1.9 million reduction in income tax expense, which is included within the caption "Income Tax (Expense) Benefit" in our accompanying consolidated statement of income for the six months ended June 30, 2011. Additionally, the sale of our ownership interest resulted in a $10.6 million non-cash reduction in our goodwill (see Note 3), and was a transaction with a related party (see Note 9). Information about our acquisition of assets from Megafleet Towing Co., Inc. is described more fully in Note 3 to our consolidated financial statements included in our 2010 Form 10-K/A.

River Consulting, LLC and Devco USA L.L.C.

Effective April 1, 2011, we sold 51% ownership interests in two separate wholly-owned subsidiaries to two separate buyers, for an aggregate consideration of $8.1 million, consisting of a $4.1 million note receivable, $1.0 million in cash, and a $3.0 million receivable for the settlement of working capital items. Following the sale, we continue to own 49% membership interests in both River Consulting, LLC, a company engaged in the business of providing engineering, consulting and management services, and Devco USA L.L.C., a company engaged in the business of processing, handling and marketing sulfur, and selling related pouring equipment. At the time of the sale, the combined carrying value of the net assets (and members' capital on a 100% basis) of both entities totaled approximately $8.8 million and consisted mostly of technology-based assets and trade receivables. We now account for our retained investments under the equity method of accounting.

In the second quarter of 2011, we recognized a $3.6 million pre-tax gain from the sale of these ownership interests (including a $2.1 million gain related to the remeasurement of our retained investment to fair value) and we included this gain within the caption "Other, net" in our accompanying consolidated statements of income for the three and six months ended June 30, 2011. We also recognized a $1.4 million increase in income tax expense related to this gain, which is included within the caption "Income Tax (Expense) Benefit" in our accompanying consolidated statement of income for the six months ended June 30, 2011.

3. Intangibles

Goodwill

We evaluate goodwill for impairment on May 31 of each year. For this purpose, we have six reporting units as follows: (i) Products Pipelines (excluding associated terminals); (ii) Products Pipelines Terminals (evaluated separately from Products Pipelines for goodwill purposes, but combined with Products Pipelines for presentation in the table below); (iii) Natural Gas Pipelines; (iv) CO_2; (v) Terminals; and (vi) Kinder Morgan Canada. There were no impairment charges resulting from our May 31, 2011 impairment testing, and no event indicating an impairment has occurred previous or subsequent to that date.

The fair value of each reporting unit was determined from the present value of the expected future cash flows from the applicable reporting unit (inclusive of a terminal value calculated using market multiples between six and ten times cash flows) discounted at a rate of 8.0%. The value of each reporting unit was determined on a stand-alone basis from the perspective of a market participant and represented the price that would be received to sell the unit as a whole in an orderly transaction between market participants at the measurement date.

Changes in the gross amounts of our goodwill and accumulated impairment losses for the six months ended June 30, 2011 are summarized as follows (in millions):

	Products Pipelines	Natural Gas Pipelines	CO_2	Terminals	Kinder Morgan Canada	Total
Historical Goodwill.	$ 263.2	$ 337.0	$ 46.1	$ 337.9	$ 626.5	$ 1,610.7
Accumulated impairment losses(a)	-	-	-	-	(377.1)	(377.1)
Balance as of December 31, 2010	263.2	337.0	46.1	337.9	249.4	1,233.6
Acquisitions	-	-	-	-	-	-
Disposals(b)	-	-	-	(10.6)	-	(10.6)
Impairments	-	-	-	-	-	-
Currency translation adjustments	-	-	-	-	7.8	7.8
Balance as of June30, 2011	$ 263.2	$ 337.0	$ 46.1	$ 327.3	$ 257.2	$ 1,230.8

(a) On April 18, 2007, we announced that we would acquire the Trans Mountain pipeline system from KMI, and we completed this transaction on April 30, 2007. Following the provisions of U.S. generally accepted accounting principles, the consideration of this transaction caused KMI to consider the fair value of the Trans Mountain pipeline system, and to determine whether goodwill related to these assets was impaired. Based on this determination, KMI recorded a goodwill impairment charge of $377.1 million in the first quarter of 2007, and because we have included all of the historical results of Trans Mountain as though the net assets had been transferred to us on January 1, 2006, this impairment is now included in our accumulated impairment losses. We have no other goodwill impairment losses.

(b) 2011 disposal amount related to the sale of our ownership interest in the boat fleeting business we acquired from Megafleet Towing Co., Inc. in April 2009 (discussed further in Note 2)

In addition, we identify any premium or excess cost we pay over our proportionate share of the underlying fair value of net assets acquired and accounted for as investments under the equity method of accounting. This premium or excess cost is referred to as equity method goodwill and is also not subject to amortization but rather to impairment testing. For all investments we own containing equity method goodwill, no event or change in circumstances that may have a significant adverse effect on the fair value of our equity investments has occurred during the first six months of 2011. As of June 30, 2011 and December 31, 2010, we reported $286.9 million and $283.0 million, respectively, in equity method goodwill within the caption "Investments" in our accompanying consolidated balance sheets.

Other Intangibles

Excluding goodwill, our other intangible assets include customer relationships, contracts and agreements, technology-based assets, and lease value. These intangible assets have definite lives and are reported separately as "Other intangibles, net" in our accompanying consolidated balance sheets. Following is information related to our intangible assets subject to amortization (in millions):

	June 30, 2011	December 31, 2010
Customer relationships, contracts and agreements		
Gross carrying amount	$ 430.3	$ 399.8
Accumulated amortization	(131.2)	(112.0)
Net carrying amount	299.1	287.8
Technology-based assets, lease value and other		
Gross carrying amount	10.6	17.9
Accumulated amortization	(3.7)	(3.5)
Net carrying amount	6.9	14.4
Total Other intangibles, net	$ 306.0	$ 302.2

The increase in the carrying amount of our customer relationships, contacts and agreements since December 31, 2010 was mainly due to the acquisition of intangibles included in our June 2011 purchase of terminal assets from TGS Development, L.P., discussed in Note 2.

We amortize the costs of our intangible assets to expense in a systematic and rational manner over their estimated useful lives. Among the factors we weigh, depending on the nature of the asset, are the effects of obsolescence, new technology, and competition. For the three and six months ended June 30, 2011, the amortization expense on our intangibles totaled $9.7 million and $19.4 million, respectively, and for the same prior year periods, the amortization expense on our intangibles totaled $11.1 million and $22.4 million, respectively. As of June 30, 2011, the weighted average amortization period for our intangible assets was approximately 15.4 years, and our estimated amortization expense for these assets for each of the next five fiscal years (2012 – 2016) is approximately $33.1 million, $29.2 million, $26.1 million, $23.3 million and $19.6 million, respectively.

4. Debt

We classify our debt based on the contractual maturity dates of the underlying debt instruments. We defer costs associated with debt issuance over the applicable term. These costs are then amortized as interest expense in our consolidated statements of income.

The net carrying amount of our debt (including both short-term and long-term amounts and excluding the value of interest rate swap agreements) as of June 30, 2011 and December 31, 2010 was $11,406.9 million and $11,539.8 million, respectively. The weighted average interest rate on all of our borrowings (both short-term and long-term) was approximately 4.29% during the second quarter of 2011, and approximately 4.33% during the second quarter of 2010. For the first six months of 2011 and 2010, the weighted average interest rate on all of our borrowings was approximately 4.36% and 4.33%, respectively.

Our outstanding short-term debt as of June 30, 2011 was $991.3 million. The balance consisted of (i) $500.0 million in principal amount of 9.00% senior notes due February 1, 2019, that may be repurchased by us at the option of the holder on February 1, 2012 pursuant to certain repurchase provisions contained in the bond indenture; (ii) $450.0 million in principal amount of 7.125% senior notes due March 15, 2012 (including discount, the notes had a carrying amount of $449.9 million as of June 30, 2011); (iii) $23.7 million in principal amount of tax-exempt bonds that mature on April 1, 2024, that are due on demand pursuant to certain standby purchase agreement provisions contained in the bond indenture (our subsidiary Kinder Morgan Operating L.P. "B" is the obligor on the bonds); (iv) a $9.6 million portion of a 5.40% long-term note payable (our subsidiaries Kinder Morgan Operating L.P. "A" and Kinder Morgan Canada Company are the obligors on the note); (v) a $7.4 million portion of 5.23% long-term senior notes (our subsidiary Kinder Morgan Texas Pipeline, L.P. is the obligor on the notes); and (vi) a $0.7 million portion of 6.00% long-term note payable (our subsidiary Kinder Morgan Arrow Terminals, L.P. is the obligor on the note).

Credit Facility

As of June 30, 2011, our $2.0 billion three-year, senior unsecured revolving credit facility had a maturity date of June 23, 2013 and could be amended to allow for borrowings of up to $2.3 billion. On July 1, 2011, we amended the credit facility to, among other things, increase the available borrowings and extend the maturity date (see "—Subsequent Event" following). The credit facility is with a syndicate of financial institutions, and the facility permits us to obtain bids for fixed rate loans from members of the lending syndicate. Wells Fargo Bank, National Association is the administrative agent, and borrowings under the credit 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 June 30, 2011 or as of December 31, 2010.

As of June 30, 2011, the amount available for borrowing under our credit facility was reduced by an aggregate amount of $231.5 million, consisting of the following letters of credit: (i) a $100.0 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 $87.9 million in three letters of credit that support tax-exempt bonds; (iii) a $16.2 million letter of credit that supports debt securities issued by the Express pipeline system; (iv) a $10.7 million letter of credit that supports our indemnification obligations on the Series D note borrowings of Cortez Capital Corporation; and (v) a combined $16.7 million in other letters of credit supporting other obligations of us and our subsidiaries.

Subsequent Event

On July 1, 2011, we amended our $2.0 billion three-year, senior unsecured revolving credit facility to, among other things, (i) allow for borrowings of up to $2.2 billion; (ii) extend the maturity of the credit facility from June 23, 2013 to July 1, 2016; (iii) permit an amendment to allow for borrowings of up to $2.5 billion; and (iv) decrease the interest rates and commitment fees for borrowings under this facility.

Commercial Paper Program

As of June 30, 2011, our commercial paper program provided for the issuance of $2.0 billion of commercial paper. In July 2011, in conjunction with the amendment to our revolving credit facility, we increased our commercial paper program to provide for the issuance of up to $2.2 billion of commercial paper. Our unsecured revolving credit facility supports our commercial paper program, and borrowings under our commercial paper program reduce the borrowings allowed under our credit facility. As of June 30, 2011, we had no commercial paper borrowings. As of December 31, 2010, we had $522.1 million of commercial paper outstanding with an average interest rate of 0.67%. The borrowings under our commercial paper program were used principally to finance the acquisitions and capital expansions we made during 2011 and 2010, and in the near term, we expect that our short-term liquidity and financing needs will be met primarily through borrowings made under our commercial paper program.

Kinder Morgan Energy Partners, L.P. Senior Notes

On March 4, 2011, we completed a public offering of $1.1 billion in principal amount of senior notes in two separate series, consisting of $500 million of 3.500% notes due March 1, 2016, and $600 million of 6.375% notes due March 1, 2041. We received proceeds from the issuance of the notes, after deducting the underwriting discount, of $1,092.7 million, and we used the proceeds to reduce the borrowings under our commercial paper program.

In addition, on March 15, 2011, we paid $700 million to retire the principal amount of our 6.75% senior notes that matured on that date. We used both cash on hand and borrowings under our commercial paper program to repay the maturing senior notes.

Subsidiary Debt

Kinder Morgan Operating L.P. "A" Debt

Effective January 1, 2007, we acquired the remaining approximately 50.2% interest in the Cochin pipeline system that we did not already own. As part of our purchase price consideration, two of our subsidiaries issued a long-term note payable to the seller having a fair value of $42.3 million. We valued the debt equal to the present value of amounts to be paid, determined using an annual interest rate of 5.40%. Our subsidiaries Kinder Morgan Operating L.P. "A" and Kinder Morgan Canada Company are the obligors on the note, and the principal amount of the note, along with interest, is due in five annual installments of $10.0 million beginning March 31, 2008. We paid the fourth installment on March 31, 2011, and as of June 30, 2011, the net present value of the note (representing the outstanding balance included as debt on our accompanying consolidated balance sheet) was $9.6 million. As of December 31, 2010, the net present value of the note was $19.2 million.

Kinder Morgan Texas Pipeline, L.P. Debt

Our subsidiary, Kinder Morgan Texas Pipeline, L.P. is the obligor on a series of unsecured senior notes, which were assumed on August 1, 2005 when we acquired a natural gas storage facility located in Liberty County, Texas from a third party. The notes have a fixed annual stated interest rate of 8.85%; however, we valued the debt equal to the present value of amounts to be paid determined using an approximate interest rate of 5.23%. The assumed principal amount, along with interest, is due in monthly installments of approximately $0.7 million, and the final payment is due January 2, 2014. During the first six months of 2011, we paid a combined principal amount of $3.6 million, and as of June 30, 2011, Kinder Morgan Texas Pipeline L.P.'s outstanding balance under the senior notes was $20.0 million. Additionally, the unsecured senior notes may be prepaid at any time in amounts of at least $1.0 million and at a price equal to the higher of par value or the present value of the remaining scheduled payments of principal and interest on the portion being prepaid. As of December 31, 2010, the outstanding balance under the notes was $23.6 million.

Kinder Morgan Arrow Terminals, L.P. Debt

On April 4, 2011, our subsidiary Kinder Morgan Arrow Terminals, L.P. acquired a parcel of land and a terminal warehouse located in Industry, Pennsylvania from a third party for an aggregate consideration of $3.3 million, consisting of $1.2 million in cash and a $2.1 million promissory note payable. The note principal is payable in three annual payments beginning in March 2012. The note bears interest at 6% per annum, and accrued interest on the unpaid principal amount is due and payable on the due date of each principal installment.

Interest Rate Swaps

Information on our interest rate swaps is contained in Note 6 "Risk Management—Interest Rate Risk Management."

Contingent Debt

Our contingent debt disclosures pertain to certain types of guarantees or indemnifications we have made and cover certain types of guarantees included within debt agreements, even if the likelihood of requiring our performance under such guarantee is remote. Most of these agreements are with entities that are not consolidated in our financial statements; however, we have invested in and hold equity ownership interests in these entities.

As of June 30, 2011, our contingent debt obligations with respect to these investments, as well as our obligations with respect to related letters of credit, are summarized below (dollars in millions):

Entity	Our Ownership Interest	Investment Type	Total Entity Debt	Our Contingent Share of Entity Debt (a)
Fayetteville Express Pipeline LLC(b).............	50%	Limited Liability	$ 968.5(c)	$ 484.3
Cortez Pipeline Company(d)	50%	General Partner	$ 139.4(e)	$ 80.4(f)
Nassau County, Florida Ocean Highway and Port Authority(g)	N/A	N/A	N/A	$ 18.3(h)

(a) Represents the portion of the entity's debt that we may be responsible for if the entity cannot satisfy its obligations.

(b) Fayetteville Express Pipeline LLC is a limited liability company and the owner of the Fayetteville Express natural gas pipeline system. The remaining limited liability company member interest in Fayetteville Express Pipeline LLC is owned by Energy Transfer Partners, L.P.

(c) Amount represents borrowings under a $1.1 billion, unsecured revolving bank credit facility that is due May 11, 2012.

(d) Cortez Pipeline Company is a Texas general partnership that owns and operates a common carrier carbon dioxide pipeline system. The remaining general partner interests are owned by ExxonMobil Cortez Pipeline, Inc., an indirect wholly-owned subsidiary of Exxon Mobil Corporation, and Cortez Vickers Pipeline Company, an indirect subsidiary of M.E. Zuckerman Energy Investors Incorporated.

(e) Amount consists of (i) $21.4 million aggregate principal amount of Series D notes due May 15, 2013 (interest on the Series D notes is paid annually and based on a fixed interest rate of 7.14% per annum); (ii) $100.0 million of variable rate Series E notes due December 11, 2012 (interest on the Series E notes is paid quarterly and based on an interest rate of three-month LIBOR plus a spread); and (iii) $18.0 million of outstanding borrowings under a $40.0 million committed revolving bank credit facility that is also due December 11, 2012.

(f) We are severally liable for our percentage ownership share (50%) of the Cortez Pipeline Company debt ($69.7 million). In addition, as of June 30, 2011, Shell Oil Company shares our several guaranty obligations jointly and severally for $21.4 million of Cortez's debt balance related to the Series D notes; however, we are obligated to indemnify Shell for the liabilities it incurs in connection with such guaranty. Accordingly, as of June 30, 2011, we have a letter of credit in the amount of $10.7 million issued by JP Morgan Chase, in order to secure our indemnification obligations to Shell for 50% of the Cortez debt balance of $21.4 million related to the Series D notes.

Further, pursuant to a Throughput and Deficiency Agreement, the partners of Cortez Pipeline Company are required to contribute capital to Cortez in the event of a cash deficiency. The agreement contractually supports the financings of Cortez Capital Corporation, a wholly-owned subsidiary of Cortez Pipeline Company, by obligating the partners of Cortez Pipeline to fund cash deficiencies at Cortez Pipeline, including anticipated deficiencies and cash deficiencies relating to the repayment of principal and interest on the debt of Cortez Capital Corporation. The partners' respective parent or other companies further severally guarantee the obligations of the Cortez Pipeline owners under this agreement.

(g) Arose from our Vopak terminal acquisition in July 2001. Nassau County, Florida Ocean Highway and Port Authority is a political subdivision of the state of Florida.

(h) We have posted a letter of credit as security for borrowings under Adjustable Demand Revenue Bonds issued by the Nassau County, Florida Ocean Highway and Port Authority. The bonds were issued for the purpose of constructing certain port improvements located in Fernandino Beach, Nassau County, Florida. Our subsidiary, Nassau Terminals LLC is the operator of the marine port facilities. The bond indenture is for 30 years and allows the bonds to remain outstanding until December 1, 2020. Principal payments on the bonds are made on the first of December each year, and corresponding reductions are made to the letter of credit. As of June 30, 2011, this letter of credit had a face amount of $18.3 million.

On February 25, 2011, Midcontinent Express Pipeline LLC entered into a three-year $75.0 million unsecured revolving bank credit facility that is due February 25, 2014. This credit facility replaced Midcontinent Express' previous $175.4 million credit facility that was terminated on February 28, 2011, and on this same date, each of its two member owners, including us, were released from their respective debt obligations under the previous guaranty agreements. Accordingly, we no longer have a contingent debt obligation with respect to Midcontinent Express Pipeline LLC. For additional information regarding our debt facilities and our contingent debt agreements, see Note 8 "Debt" and Note 12 "Commitments and Contingent Liabilities" to our consolidated financial statements included in our 2010 Form 10-K/A.

Subsequent Event

On July 28, 2011, Fayetteville Express Pipeline LLC entered into (i) a new unsecured $600.0 million term loan that is due on July 28, 2012, with the ability to extend one additional year; and (ii) a $50.0 million unsecured revolving bank credit facility that is due on July 28, 2015. These debt instruments replaced Fayetteville Express' $1.1 billion credit facility that was terminated on July 28, 2011, and on this same date, each of its two member owners (Energy Transfer Partners, L.P. and us) were released from their respective debt obligations under the previous guaranty agreements dated

November 13, 2009. Accordingly, we no longer have a contingent debt obligation with respect to Fayetteville Express Pipeline LLC.

5. Partners' Capital

Limited Partner Units

As of June 30, 2011 and December 31, 2010, our partners' capital included the following limited partner units:

	June 30, 2011	December 31, 2010
Common units	229,289,810	218,880,103
Class B units	5,313,400	5,313,400
i-units	95,105,692	91,907,987
Total limited partner units	329,708,902	316,101,490

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.

As of June 30, 2011, our total common units consisted of 212,919,382 units held by third parties, 14,646,428 units held by KMI and its consolidated affiliates (excluding our general partner), and 1,724,000 units held by our general partner. As of December 31, 2010, our total common units consisted of 202,509,675 units held by third parties, 14,646,428 units held by KMI and its consolidated affiliates (excluding our general partner), and 1,724,000 units held by our general partner.

As of both June 30, 2011 and December 31, 2010, all of our 5,313,400 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.

As of both June 30, 2011 and December 31, 2010, 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. 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.

Changes in Partners' Capital

For each of the three and six month periods ended June 30, 2011 and 2010, 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 June 30,					
	2011			2010		
	KMP	Noncontrolling interests	Total	KMP	Noncontrolling interests	Total
Beginning Balance	$ 7,018.4	$ 79.2	$ 7,097.6	$ 6,612.6	$ 78.7	$ 6,691.3
Units issued as consideration in the acquisition of assets	23.7	-	23.7	-	-	-
Units issued for cash	624.6	-	624.6	433.1	-	433.1
Distributions paid in cash	(540.7)	(6.9)	(547.6)	(480.2)	(6.0)	(486.2)
Noncash compensation expense allocated from KMI(a)	-	-	-	1.3	-	1.3
Cash contributions	-	11.3	11.3	-	5.5	5.5
Other adjustments	(0.1)	-	(0.1)	-	-	-
Comprehensive income:						
Net Income	230.5	1.4	231.9	361.2	3.9	365.1
Other comprehensive income:						
Change in fair value of derivatives utilized for hedging purposes	163.0	1.6	164.6	141.6	1.5	143.1
Reclassification of change in fair value of derivatives to net income	85.9	0.9	86.8	39.1	0.4	39.5
Foreign currency translation adjustments	10.9	0.2	11.1	(85.5)	(0.9)	(86.4)
Adjustments to pension and other postretirement benefit plan liabilities	-	-	-	(0.1)	-	(0.1)
Total other comprehensive income	259.8	2.7	262.5	95.1	1.0	96.1
Comprehensive income	490.3	4.1	494.4	456.3	4.9	461.2
Ending Balance	$ 7,616.2	$ 87.7	$ 7,703.9	$ 7,023.1	$ 83.1	$ 7,106.2

	Six Months Ended June 30,					
	2011			2010		
	KMP	Noncontrolling interests	Total	KMP	Noncontrolling interests	Total
Beginning Balance	$ 7,210.7	$ 81.8	$ 7,292.5	$ 6,644.5	$ 79.6	$ 6,724.1
Units issued as consideration pursuant to common unit compensation plan for non-employee directors	0.2	-	0.2	0.2	-	0.2
Units issued as consideration in the acquisition of assets	23.7	-	23.7	81.7	-	81.7
Units issued for cash	705.8	-	705.8	433.1	-	433.1
Distributions paid in cash	(1,072.3)	(13.5)	(1,085.8)	(949.0)	(12.0)	(961.0)
Noncash compensation expense allocated from KMI(a)	89.0	0.9	89.9	2.7	-	2.7
Cash contributions	-	13.1	13.1	-	7.2	7.2
Other adjustments	1.2	-	1.2	-	-	-
Comprehensive income:						
Net Income	568.3	4.5	572.8	586.5	6.0	592.5
Other comprehensive income:						
Change in fair value of derivatives utilized for hedging purposes	(96.8)	(1.0)	(97.8)	166.0	1.7	167.7
Reclassification of change in fair value of derivatives to net income	138.4	1.4	139.8	86.1	0.9	87.0
Foreign currency translation adjustments	61.0	0.7	61.7	(26.3)	(0.3)	(26.6)
Adjustments to pension and other postretirement benefit plan liabilities	(13.0)	(0.2)	(13.2)	(2.4)	-	(2.4)
Total other comprehensive income	89.6	0.9	90.5	223.4	2.3	225.7
Comprehensive income	657.9	5.4	663.3	809.9	8.3	818.2
Ending Balance	$ 7,616.2	$ 87.7	$ 7,703.9	$ 7,023.1	$ 83.1	$ 7,106.2

(a) For further information about this expense, see Note 9. We do not have any obligation, nor do we expect to pay any amounts related to this expense.

During the first six months of both 2011 and 2010, there were no material changes in our ownership interests in subsidiaries in which we retained a controlling financial interest.

Equity Issuances

On February 25, 2011, we entered into a second amended and restated equity distribution agreement with UBS Securities LLC to provide for the offer and sale of common units having an aggregate offering price of up to $1.2 billion (up from an aggregate offering price of up to $600 million under our first amended and restated agreement) from time to time through UBS, as our sales agent. During the three and six months ended June 30, 2011, we issued 1,247,090 and 2,377,296, respectively, of our common units pursuant to this equity distribution agreement. After commissions of $0.7 million and $1.3 million, respectively, we received net proceeds of $90.7 million and $171.9 million, respectively, from the issuance of these common units. We used the proceeds to reduce the borrowings under our commercial paper program. For additional information regarding our equity distribution agreement, see Note 10 to our consolidated financial statements included in our 2010 Form 10-K/A.

On June 10, 2011, we issued 324,961 common units as part of our purchase price for the petroleum coke terminal assets we acquired from TGS Development, L.P. We valued the common units at $23.7 million, determining the units' value based on the $73.01 closing market price of the common units on the New York Stock Exchange on the June 10, 2011 acquisition date. For more information on this acquisition, see Note 2.

On June 17, 2011, we issued, in a public offering, 6,700,000 of our common units at a price of $71.44 per unit, less commissions and underwriting expenses. At the time of the offering, we granted the underwriters a 30-day option to purchase up to an additional 1,005,000 common units from us on the same terms and conditions, and upon the underwriters' exercise of this option in full, we issued the additional 1,005,000 common units on June 27, 2011. We received net proceeds, after deducting the underwriter discount, of $533.9 million from the issuance of these 7,705,000 common units, and we used the proceeds to reduce the borrowings under our commercial paper program.

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.

On May 13, 2011, we paid a cash distribution of $1.14 per unit to our common unitholders and to our Class B unitholder for the quarterly period ended March 31, 2011. KMR, our sole i-unitholder, received a distribution of 1,599,149 i-units from us on May 13, 2011, based on the $1.14 per unit distributed to our common unitholders on that date. The distributions were declared on April 20, 2011, payable to unitholders of record as of April 29, 2011.

On May 14, 2010, we paid a cash distribution of $1.07 per unit to our common unitholders and our Class B unitholders for the quarterly period ended March 31, 2010. KMR, our sole i-unitholder, received a distribution of 1,556,130 i-units from us on May 14, 2010, based on the $1.07 per unit distributed to our common unitholders on that date. The distributions were declared on April 21, 2010, payable to unitholders of record as of April 30, 2010.

Our May 13, 2011 incentive distribution payment to our general partner for the quarterly period ended March 31, 2011 totaled $280.0 million; however, this incentive distribution was affected by a waived incentive distribution amount equal to $7.1 million related to common units issued to finance a portion of our May 2010 acquisition of a 50% ownership interest in KinderHawk Field Services LLC (beginning with our distribution payments for the quarterly period ended June 30, 2010, our general partner has agreed not to take incentive distributions related to this joint venture acquisition through year-end 2011). Our distribution of $1.07 per unit paid on May 14, 2010 for the first quarter of 2010 required an incentive distribution to our general partner of $249.4 million. The increased incentive distribution to our general partner paid for the first quarter of 2011 over the incentive distribution paid for the first quarter of 2010 reflects the increase in the amount distributed per unit as well as the issuance of additional units.

Subsequent Events

On July 20, 2011, we declared a cash distribution of $1.15 per unit for the quarterly period ended June 30, 2011. The distribution will be paid on August 12, 2011, to unitholders of record as of August 1, 2011. Our common unitholders and our Class B unitholder will receive cash. KMR will receive a distribution of 1,701,916 additional i-units based on the $1.15 distribution per common unit. For each outstanding i-unit that KMR holds, a fraction of an i-unit (0.017895) will be issued. This fraction was determined by dividing:

▪ $1.15, the cash amount distributed per common unit

by

▪ $64.265, the average of KMR's shares' closing market prices from July 14-27, 2011, 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.

Our declared distribution for the second quarter of 2011 of $1.15 per unit will result in an incentive distribution to our general partner of $292.8 million (including the effect of a waived incentive distribution amount of $7.1 million related to our KinderHawk acquisition).

Comparatively, our distribution of $1.09 per unit paid on August 13, 2010 for the second quarter of 2010 resulted in an incentive distribution payment to our general partner in the amount of $89.8 million. Under the terms of our partnership agreement, our second quarter 2010 distribution to unitholders required an incentive distribution to our general partner in the amount of $263.4 million; however, this incentive distribution was reduced by a combined $173.6 million, including (i) a waived incentive amount equal to $5.3 million related to our May 2010 KinderHawk acquisition; and (ii) a reduced incentive amount equal to $168.3 million due to a portion of our available cash distribution for the second quarter of 2010 being a distribution of cash from interim capital transactions, rather than a distribution of cash from operations (including the general partner's 2% general partner interest, its total cash distributions were reduced by $170.0 million). As provided in our partnership agreement, our general partner receives no incentive distribution on distributions of cash from interim capital transactions. For additional information about our 2010 partnership distributions, see Notes 10 and 11 to our consolidated financial statements included in our 2010 Form 10-K/A.

6. 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

We are exposed to risks associated with changes in the market price of natural gas, natural gas liquids and crude oil as a result of the forecasted purchase or sale of these products. Specifically, these risks are primarily associated with price volatility related to (i) pre-existing or anticipated physical natural gas, natural gas liquids and crude oil sales; (ii) natural gas purchases; and (iii) natural gas system use and storage. Price changes are often caused by shifts in the supply and demand for these commodities, as well as their locations.

Our principal use of energy commodity derivative contracts is to mitigate the risk associated with unfavorable market movements in the price of energy commodities. Our energy commodity derivative contracts act as a hedging (offset) mechanism against the volatility of energy commodity prices by allowing us to transfer this price risk to counterparties who are able and willing to bear it.

For derivative contracts that are designated and qualify as cash flow hedges pursuant to U.S. generally accepted accounting principles, the portion of the gain or loss on the derivative contract that is effective (as defined by U.S. generally accepted accounting principles) in offsetting the variable cash flows associated with the hedged forecasted transaction is reported as a component of other comprehensive income and reclassified into earnings in the same line item associated with the forecasted transaction and in the same period or periods during which the hedged transaction affects earnings (e.g., in "revenues" when the hedged transactions are commodity sales). The remaining gain or loss on the derivative contract in excess of the cumulative change in the present value of future cash flows of the hedged item, if any (i.e., the ineffective portion as defined by U.S. generally accepted accounting principles), is recognized in earnings during the current period.

The effectiveness of hedges using an option contract may be assessed based on changes in the option's intrinsic value with the change in the time value of the contract being excluded from the assessment of hedge effectiveness. Changes in the excluded component of the change in an option's time value are included currently in earnings. During the three and six months ended June 30, 2011, we recognized net losses of $1.8 million and net gains of $1.9 million, respectively, related to crude oil hedges and resulting from both hedge ineffectiveness and amounts excluded from effectiveness testing. During the three and six months ended June 30, 2010, we recognized net gains of $7.8 million and $14.1 million, respectively, related to crude oil and natural gas hedges and resulting from hedge ineffectiveness and amounts excluded from effectiveness testing.

Additionally, during the three and six months ended June 30, 2011, we reclassified losses of $86.8 million and $139.8 million, respectively, from "Accumulated other comprehensive loss" into earnings, and for the same comparable periods last year, we reclassified losses of $39.5 million and $87.0 million, respectively, into earnings. 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). The proceeds or payments resulting from the settlement of our cash flow hedges are reflected in the operating section of our statement of cash flows as changes to net income and working capital.

The “Accumulated other comprehensive loss” balance included in our Partners’ Capital (exclusive of the portion included in “Noncontrolling interests”) was $96.8 million as of June 30, 2011, and $186.4 million as of December 31, 2010. These totals included “Accumulated other comprehensive loss” amounts associated with energy commodity price risk management activities of $265.5 million as of June 30, 2011 and $307.1 million as of December 31, 2010. Approximately $171.5 million of the total loss amount associated with energy commodity price risk management activities and included in our Partners’ Capital as of June 30, 2011 is expected to be reclassified into earnings during the next twelve months (when the associated forecasted sales and purchases are also expected to occur), however, actual amounts could vary materially as a result of changes in market prices. As of June 30, 2011, 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 2015.

As of June 30, 2011, we had entered into the following outstanding commodity forward contracts to hedge our forecasted energy commodity purchases and sales:

	Net open position long/(short)
Derivatives designated as hedging contracts	
Crude oil	(24.2) million barrels
Natural gas fixed price	(28.5) billion cubic feet
Natural gas basis	(28.5) billion cubic feet
Derivatives not designated as hedging contracts	
Natural gas fixed price	(0.1) billion cubic feet
Natural gas basis	(5.2) billion cubic feet

For derivative contracts that are not designated as a hedge for accounting purposes, all realized and unrealized gains and losses are recognized in the statement of income during the current period. These types of transactions include basis spreads, basis-only positions and gas daily swap positions. We primarily enter into these positions to economically hedge an exposure through a relationship that does not qualify for hedge accounting. Until settlement occurs, this will result in non-cash gains or losses being reported in our operating results.

Interest Rate Risk Management

In order to maintain a cost effective capital structure, it is our policy to borrow funds using a mix of fixed rate debt and variable rate debt. We use interest rate swap agreements to manage the interest rate risk associated with the fair value of our fixed rate borrowings and to effectively convert a portion of the underlying cash flows related to our long-term fixed rate debt securities into variable rate cash flows in order to achieve our desired mix of fixed and variable rate debt.

Since the fair value of fixed rate debt varies inversely with changes in the market rate of interest, we enter into swap agreements to receive a fixed and pay a variable rate of interest in order to convert the interest expense associated with certain of our senior notes from fixed rates to variable rates, resulting in future cash flows that vary with the market rate of interest. These swaps, therefore, hedge against changes in the fair value of our fixed rate debt that result from market interest rate changes. For derivative contracts that are designated and qualify as a fair value hedge, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in current earnings.

As of June 30, 2011, we had a combined notional principal amount of $5,275 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 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 June 30, 2011, 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 January 15, 2038.

As of December 31, 2010, we had a combined notional principal amount of $4,775 million of fixed-to-variable interest rate swap agreements. In the first quarter of 2011, we entered into four additional fixed-to-variable interest rate swap agreements having a combined notional principal amount of $500 million. Each agreement effectively converts a portion of the interest expense associated with our 3.50% senior notes due March 1, 2016 from a fixed rate to a variable rate based on an interest rate of LIBOR plus a spread.

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" on 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 June 30, 2011 and December 31, 2010 (in millions):

Fair Value of Derivative Contracts

		Asset derivatives		Liability derivatives	
	Balance sheet location	June 30, 2011 Fair value	December 31, 2010 Fair value	June 30, 2011 Fair value	December 31, 2010 Fair value
Derivatives designated as hedging contracts					
Energy commodity derivative contracts	Current	$ 29.9	$ 20.1	$ (207.7)	$ (275.9)
	Non-current	29.5	43.1	(126.4)	(103.0)
Subtotal		59.4	63.2	(334.1)	(378.9)
Interest rate swap agreements	Current	8.0	-	-	-
	Non-current	262.8	217.6	(58.1)	(69.2)
Subtotal		270.8	217.6	(58.1)	(69.2)
Total		330.2	280.8	(392.2)	(448.1)
Derivatives not designated as hedging contracts					
Energy commodity derivative contracts	Current	1.9	3.9	(1.4)	(5.6)
Total		1.9	3.9	(1.4)	(5.6)
Total derivatives		$ 332.1	$ 284.7	$ (393.6)	$ (453.7)

The offsetting entry to adjust the carrying value of the debt securities whose fair value was being hedged is included within "Value of interest rate swaps" on our accompanying consolidated balance sheets, which also includes any unamortized portion of proceeds received from the early termination of interest rate swap agreements. As of June 30, 2011 and December 31, 2010, this unamortized premium totaled $435.3 million and $456.5 million, respectively, and as of June 30, 2011, the weighted average amortization period for this premium was approximately 16.9 years.

Effect of Derivative Contracts on the Income Statement

The following three tables summarize the impact of our derivative contracts on our accompanying consolidated statements of income for each of the three and six months ended June 30, 2011 and 2010 (in millions):

Derivatives in fair value hedging relationships	Location of gain/(loss) recognized in income on derivative	Amount of gain/(loss) recognized in income on derivative(a)			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2011	2010	2011	2010
Interest rate swap agreements	Interest, net - income/(expense)	$ 128.2	$ 348.6	$ 64.3	$ 414.2
Total		$ 128.2	$ 348.6	$ 64.3	$ 414.2

Hedged items in fair value hedging relationships	Location of gain/(loss) recognized in income on related hedged item	Amount of gain/(loss) recognized in income on related hedged item(a)			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2011	2010	2011	2010
Fixed rate debt	Interest, net - income/(expense)	$ (128.2)	$ (348.6)	$ (64.3)	$ (414.2)
Total		$ (128.2)	$ (348.6)	$ (64.3)	$ (414.2)

(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. Amounts do not reflect the impact on interest expense from the interest rate swap agreements under which we pay variable rate interest and receive fixed rate interest.

Derivatives in cash flow hedging relationships	Amount of gain/(loss) recognized in OCI on derivative (effective portion)		Location of gain/(loss) recognized from Accumulated OCI into income (effective portion)	Amount of gain/(loss) reclassified from Accumulated OCI into income (effective portion)		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 June 30,			Three Months Ended June 30,			Three Months Ended June 30,	
	2011	2010		2011	2010		2011	2010
Energy commodity derivative contracts	$ 164.6	$ 143.1	Revenues–natural gas sales	$ 0.1	$ 1.7	Revenues–natural gas sales	$ -	$ -
			Revenues–product sales and other	(87.0)	(48.4)	Revenue–product sales and other	(1.8)	7.9
			Gas purchases and other costs of sales	0.1	7.2	Gas purchases and other costs of sales	-	(0.1)
Total	$ 164.6	$ 143.1	Total	$ (86.8)	$ (39.5)	Total	$ (1.8)	$ 7.8
	Six Months Ended June 30,			Six Months Ended June 30,			Six Months Ended June 30,	
	2011	2010		2011	2010		2011	2010
Energy commodity derivative contracts	$ (97.8)	$ 167.7	Revenues–natural gas sales	$ 1.0	$ 1.7	Revenues–natural gas sales	$ -	$ -
			Revenue–product sales and other	(152.2)	(98.4)	Revenue–product sales and other	1.9	13.3
			Gas purchases and other costs of sales	11.4	9.7	Gas purchases and other costs of sales	-	0.8
Total	$ (97.8)	$ 167.7	Total	$ (139.8)	$ (87.0)	Total	$ 1.9	$ 14.1

Derivatives not designated as hedging contracts	Location of gain/(loss) recognized in income on derivative	Amount of gain/(loss) recognized in income on derivative			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2011	2010	2011	2010
Energy commodity derivative contracts	Gas purchases and other costs of sales	$ 0.1	$ 0.1	$ 0.2	$ 0.8
Total		$ 0.1	$ 0.1	$ 0.2	$ 0.8

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 June 30, 2011 was (in millions):

	Asset position
Interest rate swap agreements	$ 270.8
Energy commodity derivative contracts	61.3
Gross exposure	332.1
Netting agreement impact	(42.1)
Net exposure	$ 290.0

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 June 30, 2011 and December 31, 2010, 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 June 30, 2011 and December 31, 2010, our counterparties associated with our energy commodity contract positions and over-the–counter swap agreements had margin deposits with us totaling $1.2 million and $2.4 million, respectively, and we reported these amounts within “Accrued other current liabilities” 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. Based on contractual provisions as of June 30, 2011, we estimate that if our credit rating was downgraded, we would have the following additional collateral obligations (in millions):

Credit ratings downgraded (a)	Incremental obligations	Cumulative obligations(b)
One notch to BBB-/Baa3	$ -	$ -
Two notches to below BBB-/Baa3 (below investment grade)	$ 54.0	$ 54.0

(a) If there are split ratings among the independent credit rating agencies, most counterparties use the higher credit rating to determine our incremental collateral obligations, while the remaining use the lower credit rating. Therefore, a two notch downgrade to below BBB-/Baa3 by one agency would not trigger the entire $54.0 million incremental obligation.

(b) Includes current posting at current rating.

7. Fair Value

The Codification emphasizes that fair value is a market-based measurement that should be determined based on assumptions (inputs) that market participants would use in pricing an asset or liability. Inputs may be observable or unobservable, and valuation techniques used to measure fair value should maximize the use of relevant observable inputs and minimize the use of unobservable inputs. Accordingly, the Codification establishes a hierarchal disclosure framework that ranks the quality and reliability of information used to determine fair values. The hierarchy is associated with the level of pricing observability utilized in measuring fair value and defines three levels of inputs to the fair value measurement process—quoted prices are the most reliable valuation inputs, whereas model values that include inputs based on unobservable data are the least reliable. 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 June 30, 2011 and December 31, 2010, based on the three levels established by the Codification (in millions). The fair value measurements in the tables below do not include cash margin deposits made by us or our counterparties, which would be reported within "Restricted deposits" and "Accrued other liabilities," respectively, in our accompanying consolidated balance sheets.

	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 June 30, 2011				
Energy commodity derivative contracts(a)	$ 61.3	$ 13.5	$ 15.2	$ 32.6
Interest rate swap agreements	$ 270.8	$ -	$ 270.8	$ -
As of December 31, 2010				
Energy commodity derivative contracts(a)	$ 67.1	$ -	$ 23.5	$ 43.6
Interest rate swap agreements	$ 217.6	$ -	$ 217.6	$ -

	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 June 30, 2011				
Energy commodity derivative contracts(a)	$ (335.5)	$ (2.5)	$ (307.1)	$ (25.9)
Interest rate swap agreements	$ (58.1)	$ -	$ (58.1)	$ -
As of December 31, 2010				
Energy commodity derivative contracts(a)	$ (384.5)	$ -	$ (359.7)	$ (24.8)
Interest rate swap agreements	$ (69.2)	$ -	$ (69.2)	$ -

(a) Level 1 consists primarily of NYMEX natural gas futures. Level 2 consists primarily of OTC West Texas Intermediate swaps and OTC natural gas swaps that are settled on NYMEX. Level 3 consists primarily of natural gas basis swaps and West Texas Intermediate options.

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 and six months ended June 30, 2011 and 2010 (in millions):

Significant unobservable inputs (Level 3)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	**2010**	**2011**	**2010**
Derivatives-net asset (liability)				
Beginning of Period	$ (3.2)	$ 22.6	$ 18.8	$ 13.0
Transfers into Level 3	-	-	-	-
Transfers out of Level 3	-	-	-	-
Total gains or (losses):				
Included in earnings	2.7	11.1	2.8	11.1
Included in other comprehensive income	7.3	7.0	(15.5)	15.6
Purchases	-	-	4.6	-
Issuances	-	-	-	-
Sales	-	-	-	-
Settlements	(0.1)	5.9	(4.0)	6.9
End of Period	$ 6.7	$ 46.6	$ 6.7	$ 46.6
The amount of total gains or (losses) for the period included in earnings attributable to the change in unrealized gains or (losses) relating to assets held at the reporting date	$ (3.7)	$ 8.9	$ 1.0	$ 10.1

Fair Value of Financial Instruments

Fair value as used in the disclosure of financial instruments represents the amount at which an instrument could be exchanged in a current transaction between willing parties. As of each reporting date, the estimated fair value of our outstanding publicly-traded debt is based upon quoted market prices, if available, and for all other debt, fair value is based upon prevailing interest rates currently available to us. In addition, we adjust (discount) the fair value measurement of our long-term debt for the effect of credit risk.

The estimated fair value of our outstanding debt balance as of June 30, 2011 and December 31, 2010 (both short-term and long-term, but excluding the value of interest rate swaps) is disclosed below (in millions):

	June 30, 2011		December 31, 2010	
	Carrying Value	**Estimated fair value**	**Carrying Value**	**Estimated fair value**
Total debt	$ 11,406.9	$ 12,389.9	$ 11,539.8	$ 12,443.4

8. Reportable Segments

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

- Products Pipelines— the transportation and terminaling of refined petroleum products, including gasoline, diesel fuel, jet fuel and natural gas liquids;
- 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;
- 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.

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 June 30,		Six Months Ended June 30,	
	2011	**2010**	**2011**	**2010**
Revenues				
Products Pipelines				
Revenues from external customers	$ 227.4	$ 226.3	$ 453.0	$ 433.8
Natural Gas Pipelines				
Revenues from external customers	1,044.3	1,029.7	2,063.7	2,266.4
CO_2				
Revenues from external customers	350.0	314.6	690.8	636.4
Terminals				
Revenues from external customers	320.3	320.3	651.7	624.1
Intersegment revenues	0.2	0.2	0.5	0.5
Kinder Morgan Canada				
Revenues from external customers	77.3	70.6	152.9	130.4
Total segment revenues	2,019.5	1,961.7	4,012.6	4,091.6
Less: Total intersegment revenues	(0.2)	(0.2)	(0.5)	(0.5)
Total consolidated revenues	$ 2,019.3	$ 1,961.5	$ 4,012.1	$ 4,091.1

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	**2010**	**2011**	**2010**
Segment earnings before depreciation, depletion, amortization And amortization of excess cost of equity investments(a)				
Products Pipelines(b)	$ 20.7	$ 165.2	$ 201.2	$ 171.6
Natural Gas Pipelines	181.3	185.0	403.9	405.6
CO_2	266.4	249.4	528.4	502.6
Terminals	170.3	165.5	344.7	316.0
Kinder Morgan Canada	53.6	43.9	101.5	88.9
Total segment earnings before DD&A	692.3	809.0	1,579.7	1,484.7
Total segment depreciation, depletion and amortization	(229.4)	(223.2)	(451.2)	(450.5)
Total segment amortization of excess cost of investments	(1.6)	(1.5)	(3.1)	(2.9)
General and administrative expenses(c)	(97.4)	(93.4)	(286.6)	(194.5)
Unallocable interest expense, net of interest income	(129.6)	(123.8)	(261.3)	(240.1)
Unallocable income tax expense	(2.4)	(2.0)	(4.7)	(4.2)
Total consolidated net income	$ 231.9	$ 365.1	$ 572.8	$ 592.5

	June 30, 2011	December 31, 2010
Assets		
Products Pipelines	$ 4,384.0	$ 4,369.1
Natural Gas Pipelines	8,753.7	8,809.7
CO_2	2,148.2	2,141.2
Terminals	4,366.7	4,138.6
Kinder Morgan Canada	1,911.7	1,870.0
Total segment assets	21,564.3	21,328.6
Corporate assets(d)	777.4	532.5
Total consolidated assets	$ 22,341.7	$ 21,861.1

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

(b) Three and six month 2011 amounts include a $165.0 million increase in expense associated with rate case liability adjustments. Six month 2010 amount includes a $158.0 million increase in expense associated with rate case liability adjustments.

(c) Six month 2011 amount includes an $87.1 million increase in expense associated with a one-time special cash bonus payment paid to non-senior management employees in May 2011; however, we do not have any obligation, nor do we expect to pay any amounts related to this expense.

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

9. Related Party Transactions

Notes Receivable

Plantation Pipe Line Company

We have a current note receivable bearing interest at the rate of 4.72% per annum from Plantation Pipe Line Company, our 51.17%-owned equity investee. We received a principal repayment in the amount of $1.4 million in June 2011, and the note provides for a final payment of principal and interest on July 20, 2011. As of June 30, 2011 and December 31, 2010, the outstanding note receivable balance was $80.7 million and $82.1 million, respectively, and we included these amounts within "Accounts, notes and interest receivable, net," on our accompanying consolidated balance sheets.

Subsequent Event

On July 20, 2011, we, ExxonMobil, and Plantation Pipe Line Company amended the term loan agreement covering the note discussed above in "Notes Receivable—Plantation Pipe Line Company." Together, we agreed to (i) reduce the aggregate loan amount to $100.0 million following payments of $57.9 million made on July 20, 2011 (after these payments, the outstanding principal amount of the note is now $100.0 million, and our 51.17% portion is $51.2 million); (ii) extend the maturity of the note from July 20, 2011 to July 20, 2016; (iii) allow for pre-payment of all or any portion of the principal amount of the loan without a premium penalty; and (iv) revise the interest rate on the note from 4.72% per annum to 4.25% per annum. Following the July 20, 2011 payments to both us and ExxonMobil, the note provides for semiannual payments of principal and interest on December 31 and June 30 each year beginning on December 31, 2011, with a final principal payment of $87.8 million due on July 20, 2016.

Express US Holdings LP

In conjunction with the acquisition of our 33 1/3% equity ownership interest in the Express pipeline system from KMI on August 28, 2008, we acquired a long-term investment in a C$113.6 million debt security issued by Express US Holdings LP (the obligor), the partnership that maintains ownership of the U.S. portion of the Express pipeline system. The debenture is denominated in Canadian dollars, due in full on January 9, 2023, bears interest at the rate of 12.0% per annum, and provides for quarterly payments of interest in Canadian dollars on March 31, June 30, September 30 and

December 31 each year. As of June 30, 2011 and December 31, 2010, the outstanding note receivable balance, representing the translated amount included in our consolidated financial statements in U.S. dollars, was $117.8 million and $114.2 million, respectively, and we included these amounts within "Notes receivable" on our accompanying consolidated balance sheets.

Other Receivables and Payables

As of June 30, 2011 and December 31, 2010, our related party receivables (other than notes receivable discussed above in "—Notes Receivable") totaled $9.3 million and $15.4 million, respectively. The June 30, 2011 receivables amount consisted of (i) $6.9 million included within "Accounts, notes and interest receivable, net" on our accompanying consolidated balance sheet; and (ii) $2.4 million of natural gas imbalance receivables included within "Other current assets." The $6.9 million receivable amount primarily consisted of amounts due from Plantation Pipe Line Company and the Express pipeline system. The $2.4 million natural gas imbalance receivable amount primarily consisted of amounts due from Natural Gas Pipeline Company of America LLC, a 20%-owned equity investee of KMI and referred to in this report as NGPL.

The December 31, 2010 receivables amount consisted of (i) $8.2 million included within "Accounts, notes and interest receivable, net" on our accompanying consolidated balance sheet; and (ii) $7.2 million of natural gas imbalance receivables included within "Other current assets." The $8.2 million amount primarily related to accounts and interest receivables due from (i) the Express pipeline system; (ii) NGPL; and (iii) Plantation Pipe Line Company. Our related party natural gas imbalance receivables consisted of amounts due from NGPL.

As of June 30, 2011 and December 31, 2010, our related party payables totaled $4.4 million and $8.8 million, respectively. The June 30, 2011 related party payable amount included a $3.3 million payable to KMI included within "Accounts payable" on our accompanying consolidated balance sheet. The December 31, 2010 amount consisted of (i) $5.1 million included within "Accounts payable" and primarily related to amounts due to KMI; and (ii) $3.7 million of natural gas imbalance payables included within "Accrued other current liabilities" and consisting of amounts due to the Rockies Express pipeline system.

Asset Acquisitions

In conjunction with our acquisition of (i) certain Natural Gas Pipelines assets and partnership interests from KMI in December 1999 and December 2000; and (ii) all of the ownership interest in TransColorado Gas Transmission Company LLC from two wholly-owned subsidiaries of KMI on November 1, 2004, KMI agreed to indemnify us and our general partner with respect to approximately $733.5 million 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.

Asset Divestitures

Mr. C. Berdon Lawrence, a non-management director on the boards of our general partner and KMR until July 20, 2011, is also Chairman Emeritus of the Board of Kirby Corporation. On February 9, 2011, we sold a marine vessel to Kirby Corporation's subsidiary Kirby Inland Marine, L.P., and additionally, we and Kirby Inland Marine L.P. formed a joint venture named Greens Bayou Fleeting, LLC. For more information about these transactions, see Note 2.

Non-cash Compensation Expenses

In the first six months of 2011 and 2010, KMI allocated to us certain non-cash compensation expenses totaling $89.9 million and $2.7 million, respectively. The 2011 amount consisted of an $87.1 million first quarter expense associated with a one-time special cash bonus payment that was paid to non-senior management employees in May 2011, and a $2.8 million first quarter expense associated with KMI's May 2007 going–private transaction. The 2010 amount consisted of a $1.4 million first quarter expense and a $1.3 million second quarter expense, both related to KMI's going–private transaction. However, we do not have any obligation, nor do we expect to pay any amounts related to these 2011 and 2010 compensation expenses, and since we will not be responsible for paying these expenses, we recognized the amounts allocated to us as both an expense on our income statement and a contribution to "Total Partners' Capital" on our balance sheet.

Derivative Counterparties

As a result of KMI's going-private transaction in May 2007, a number of individuals and entities became significant investors in KMI, and by virtue of the size of its ownership interest in KMI, one of those investors—Goldman Sachs Capital Partners and certain of its affiliates—remains a "related party" (as defined by U.S. generally accepted accounting principles) to us as of June 30, 2011. Goldman Sachs has also acted in the past, and may act in the future, as an underwriter for equity and/or debt issuances for us, and Goldman Sachs effectively owned 49% of the terminal assets we acquired from US Development Group LLC in January 2010.

In addition, we conduct energy commodity risk management activities in the ordinary course of implementing our risk management strategies in which the counterparty to certain of our derivative transactions is an affiliate of Goldman Sachs, and in conjunction with these activities, we are a party (through one of our subsidiaries engaged in the production of crude oil) to a hedging facility with J. Aron & Company/Goldman Sachs. The hedging facility requires us to provide certain periodic information, but does not require the posting of margin. As a result of changes in the market value of our derivative positions, we have created both amounts receivable from and payable to Goldman Sachs affiliates.

The following table summarizes the fair values of our energy commodity derivative contracts that are (i) associated with commodity price risk management activities with J. Aron & Company/Goldman Sachs; and (ii) included within "Fair value of derivative contracts" on our accompanying consolidated balance sheets as of June 30, 2011 and December 31, 2010 (in millions):

	June 30, 2011	December 31, 2010
Derivatives – asset/(liability)		
Current assets	$ 7.6	$ -
Noncurrent assets	$ 6.0	$ 12.7
Current liabilities	$ (158.2)	$ (221.4)
Noncurrent liabilities	$ (52.8)	$ (57.5)

For more information on our risk management activities see Note 6.

Other

Generally, KMR makes all decisions relating to the management and control of our business, and in general, KMR has a fiduciary 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 fiduciary 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 fiduciary 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 to our consolidated financial statements included in our 2010 Form 10-K/A.

10. Litigation, Environmental and Other Contingencies

Below is a brief description of our ongoing material legal proceedings, including any material developments that occurred in such proceedings during the six months ended June 30, 2011. Additional information with respect to these proceedings can be found in Note 16 to our consolidated financial statements that were included in our 2010 Form 10-K/A. This note also contains a description of any material legal proceedings that were initiated against us during the six months ended June 30, 2011, and a description of any material events occurring subsequent to June 30, 2011, but before the filing of this report.

In this note, we refer to our subsidiary SFPP, L.P. as SFPP; our subsidiary Calnev Pipe Line LLC as Calnev; Chevron Products Company as Chevron; BP West Coast Products, LLC as BP; ConocoPhillips Company as ConocoPhillips; Tesoro Refining and Marketing Company as Tesoro; Western Refining Company, L.P. as Western Refining; Navajo Refining Company, L.L.C. as Navajo; Holly Refining & Marketing Company LLC as Holly; ExxonMobil Oil Corporation as ExxonMobil; Valero Energy Corporation as Valero; Valero Marketing and Supply Company as Valero Marketing; Continental Airlines, Inc., Northwest Airlines, Inc., Southwest Airlines Co. and US Airways, Inc., collectively, as the Airlines; our subsidiary Kinder Morgan CO_2 Company, L.P. (the successor to Shell CO_2 Company, Ltd.) as Kinder Morgan CO_2; the United States Court of Appeals for the District of Columbia Circuit as the D.C. Circuit; the Federal Energy Regulatory Commission as the FERC; the California Public Utilities Commission as the CPUC; the Union Pacific Railroad Company (the successor to Southern Pacific Transportation Company) as UPRR; the Texas Commission of Environmental Quality as the TCEQ; The Premcor Refining Group, Inc. as Premcor; Port Arthur Coker Company as PACC; the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration as the PHMSA; our subsidiary Kinder Morgan Bulk Terminals, Inc. as KMBT; our subsidiary Kinder Morgan Liquids Terminals LLC as KMLT; our subsidiary Kinder Morgan Interstate Gas Transmission LLC as KMIGT; Rockies Express Pipeline LLC as Rockies Express; and Plantation Pipe Line Company as Plantation. "OR" dockets designate complaint proceedings, and "IS" dockets designate protest proceedings.

Federal Energy Regulatory Commission Proceedings

The tariffs and rates charged by SFPP and Calnev are subject to a number of ongoing proceedings at the FERC, including the shippers' complaints and protests regarding interstate rates on the pipeline systems listed below. In general, these complaints and protests allege the rates and tariffs charged by SFPP and Calnev are not just and reasonable. 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: (i) whether certain of our Pacific operations' rates are "grandfathered" under the Energy Policy Act of 1992, and therefore deemed to be just and reasonable; (ii) whether "substantially changed circumstances" have occurred with respect to any grandfathered rates such that those rates could be challenged; (iii) whether indexed rate increases are justified; and (iv) the appropriate level of return and income tax allowance we may include in our rates.

SFPP

Pursuant to FERC approved settlements, SFPP settled with eleven of twelve shipper litigants in May 2010 and with Chevron in March 2011 a wide range of rate challenges dating back to 1992 (Historical Cases Settlements). Settlement payments were made to the eleven shippers in June 2010 and to Chevron in March 2011.

The Historical Cases Settlements and other legal reserves related to SFPP rate litigation resulted in a $172.0 million charge to earnings in 2010. In June 2010, we made settlement payments of $206.3 million to eleven of the litigant shippers. Due to this settlement payment and the reserve we took at that time for potential future settlements with Chevron (since resolved) and our CPUC cases described below, a portion of our partnership distributions for the second quarter of 2010 (which we paid in August 2010) was a distribution of cash from interim capital transactions (rather than a distribution of cash from operations). As a result, our general partner's cash distributions for the second quarter of 2010 were reduced by $170.0 million. As provided in our partnership agreement, our general partner receives no incentive distribution on distributions of cash from interim capital transactions; accordingly, our second quarter 2010 interim capital transaction distribution increased our cumulative excess cash coverage (cumulative excess cash coverage is cash from operations generated since our inception in excess of cash distributions paid). This interim capital transaction also allowed us to resolve the Chevron settlement and should allow us to resolve the CPUC rate cases (discussed below) without impacting future distributions. For more information on our partnership distributions, see Note 10 "Partners'

Capital—Income Allocation and Declared Distributions" to our consolidated financial statements included in our 2010 Form 10-K/A.

The Historical Cases Settlements resolved at the time all but two of the interstate rate cases outstanding between SFPP and the twelve litigant shippers. Since that time, additional challenges regarding SFPP's current rates have been filed with the FERC.

The following FERC dockets, which pertain to all protesting shippers, are currently pending:

- FERC Docket No. IS08-390 (West Line Rates) (Opinion 511)—Protestants: BP, ExxonMobil, ConocoPhillips, Valero Marketing, Chevron, the Airlines—Status: FERC order issued on February 17, 2011. While the order made certain findings that were adverse to SFPP, it ruled in favor of SFPP on many significant issues. Subsequently, SFPP made a compliance filing which estimates approximately $16.0 million in refunds. However, SFPP also filed a rehearing request on certain adverse rulings in the FERC order. It is not possible to predict the outcome of the FERC review of the rehearing request or appellate review of this order;

- FERC Docket No. IS09-437 (East Line Rates)—Protestants: BP, ExxonMobil, ConocoPhillips, Valero Marketing, Chevron, Western Refining, Navajo, Holly, and Southwest Airlines—Status: Initial decision issued on February 10, 2011. A FERC administrative law judge generally made findings adverse to SFPP, found that East Line rates should have been lower, and recommended that SFPP pay refunds for alleged over-collections. SFPP has filed a brief with the FERC taking exception to these and other portions of the initial decision. The FERC will review the initial decision, and while the initial decision is inconsistent with a number of the issues ruled on in FERC's Opinion 511, it is not possible to predict the outcome of FERC or appellate review;

- FERC Docket No. IS11-444 (2011 Index Rate Increases)—Protestants: BP, ExxonMobil, ConocoPhillips, Valero Marketing, Chevron, the Airlines, Tesoro, Western Refining, Navajo, and Holly—Status: Rates accepted and suspended, subject to refund, and case before a FERC settlement judge;

- FERC Docket No. OR11-13 (SFPP Base Rates)—Complainant: ConocoPhillips—Status: Complaint pending before the FERC;

- FERC Docket No. OR11-14 (SFPP Indexed Rates)—Complainant: ConocoPhillips—Status: Complaint pending before the FERC;

- FERC Docket No. OR11-15 (SFPP Base Rates)—Complainant: Chevron—Status: Complaint pending before the FERC;

- FERC Docket No. OR11-16 (SFPP Indexed Rates)—Complainant: Chevron—Status: Complaint pending before the FERC;

- FERC Docket No. OR11-18 (SFPP Base Rates)—Complainant: Tesoro—Status: Complaint pending before the FERC; and

- FERC Docket No. OR11-19 (SFPP Indexed Rates)—Complainant: Tesoro—Status: Complaint pending before the FERC.

With respect to the SFPP proceedings above and the Calnev proceedings discussed below, we estimate that the shippers are seeking approximately $50 million in annual rate reductions and $140 million in refunds. However, applying the principles of Opinion 511, a full FERC decision on our West Line Rates, to these cases would result in substantially lower rate reductions and refunds. In the second quarter of 2011, we recorded a $165.0 million expense and increased our litigation reserve related to these cases and the litigation discussed below involving SFPP and the CPUC. We do not expect refunds in these cases to have an impact on our distributions to our limited partners.

Calnev

On March 17, 2011, the FERC issued an order consolidating the following proceedings and setting them for hearing. The FERC further held the hearing proceedings in abeyance to allow for settlement judge proceedings:

- FERC Docket Nos. OR07-7, OR07-18, OR07-19, OR07-22, OR09-15, and OR09-20 (consolidated) (Calnev Rates)—Complainants: Tesoro, Airlines, BP, Chevron, ConocoPhillips and Valero Marketing—Status: Before a FERC settlement judge.

Trailblazer Pipeline Company LLC

On July 7, 2010, our subsidiary Trailblazer Pipeline Company LLC refunded a total of approximately $0.7 million to natural gas shippers covering the period January 1, 2010 through May 31, 2010 as part of a settlement reached with shippers to eliminate the December 1, 2009 rate filing obligation contained in its Docket No. RP03-162 rate case settlement. As part of the agreement with shippers, Trailblazer commenced billing reduced tariff rates as of June 1, 2010 with an additional reduction in tariff rates that took effect January 1, 2011.

Kinder Morgan Interstate Gas Transmission LLC Section 5 Proceeding

On November 18, 2010, our subsidiary KMIGT was notified by the FERC of a proceeding against it pursuant to Section 5 of the Natural Gas Act. The proceeding set for hearing a determination of whether KMIGT's current rates, which were approved by the FERC in KMIGT's last transportation rate case settlement, remain just and reasonable. The FERC made no findings in its order as to what would constitute just and reasonable rates or a reasonable return for KMIGT. A proceeding under Section 5 of the Natural Gas Act is prospective in nature and any potential change in rates charged customers by KMIGT can only occur after the FERC has issued a final order. Prior to that, an administrative law judge presides over an evidentiary hearing and makes an initial decision (which the FERC has directed to be issued within 47 weeks). On March 23, 2011, the Chief Judge suspended the procedural schedule in this proceeding because all parties have reached a settlement in principle that will resolve all issues set for hearing. A formal settlement document, which is supported or not opposed by all parties of record, was filed on May 5, 2011. This settlement document is referred to in this Note as the Settlement, and is pending approval of the FERC. The Settlement resolves all issues in the proceeding and provides shippers on KMIGT's system with prospective reductions in the fuel and gas and lost and unaccounted for rates, referred to as the Fuel Retention Factors, effective June 1, 2011. The Settlement, upon approval and implementation, will result in a 27% reduction in the Fuel Retention Factors billed to shippers effective June 1, 2011, as compared to the Fuel Retention Factors approved and in effect on March 1, 2011. The Settlement also provides for a second stepped reduction, resulting in a total 30% reduction in the Fuel Retention Factors billed to shippers and effective January 1, 2012, for certain segments of the former Pony Express pipeline system. Except for these reductions to the Fuel Retention Factors, other transportation and storage rates will not be altered by the Settlement. The Settlement calls for the issuance of refunds to allow for shippers to receive the value of lower Fuel Retention Factors on June 1, 2011.

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 been consolidated and assigned to two administrative law judges.

On April 6, 2010, a CPUC administrative law judge issued a proposed decision in several intrastate rate cases involving SFPP and a number of its shippers. The proposed decision includes determinations on issues, such as SFPP's entitlement to an income tax allowance and allocation of environmental expenses, which we believe are contrary both to CPUC policy and precedent and to established federal regulatory policies for pipelines. Moreover, the proposed decision orders refunds relating to these issues where the underlying rates were previously deemed reasonable by the CPUC, which we believe to be contrary to California law. SFPP filed comments on May 3, 2010 outlining what it believes to be the errors in law and fact within the proposed decision, and on May 5, 2010, SFPP made oral arguments before the full CPUC. On November 12, 2010, an alternate proposed decision was issued.

On May 26, 2011, the CPUC issued an order adopting the proposed decision, which would eliminate from SFPP's transportation rates an allowance for income taxes on income generated by SFPP. The order also calls for partial refund of rates charged to shippers that were previously deemed reasonable by the CPUC. The order would only affect rates for SFPP's intrastate pipeline service within the state of California and would have no effect on SFPP's interstate rates, which do include such an allowance under orders of the FERC and opinions of the U.S. Court of Appeals for the District of Columbia. On this same date, we announced that we will seek rehearing and pursue other legal options to overturn the CPUC's order.

On June 22, 2011, a CPUC administrative law judge issued a proposed decision substantially reducing SFPP's authorized cost of service, requiring SFPP's prospective rates to be reduced to reflect the 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. SFPP filed comments on the proposed decision on June 22, 2011, outlining what it believes to be errors in law and fact in the proposed decision, including the requirement that refunds be made from May 24, 2007. SFPP has requested oral argument before the CPUC. The earliest anticipated date for CPUC consideration of the proposed decision is August 18, 2011.

Based on our review of these CPUC proceedings and the shipper comments thereon, we estimate that the shippers are requesting approximately $360 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 we believe that the appropriate application of the May 26, 2011 CPUC order and the June 22, 2011 administrative law decision will result in a considerably lower amount. In addition, further procedural steps, including motions for rehearing and writ of review to California's Court of Appeals, will be taken with respect to these decisions. We do not expect any reparations that we would pay in these matters to have an impact on our distributions to our limited partners.

Carbon Dioxide Litigation

CO_2 Claims Arbitration

Kinder Morgan CO_2 and Cortez Pipeline Company were among the named defendants in *CO_2 Committee, Inc. v. Shell Oil Co., et al.*, an arbitration initiated on November 28, 2005. The arbitration arose from a dispute over a class action settlement agreement which became final on July 7, 2003 and disposed of five lawsuits formerly pending in the U.S. District Court, District of Colorado. The plaintiffs in such lawsuits primarily included overriding royalty interest owners, royalty interest owners, and small share working interest owners who alleged underpayment of royalties and other payments on carbon dioxide produced from the McElmo Dome unit.

The settlement imposed certain future obligations on the defendants in the underlying litigation. The plaintiffs in the arbitration alleged that, in calculating royalty and other payments, defendants used a transportation expense in excess of what is allowed by the settlement agreement, thereby causing alleged underpayments of approximately $12 million. The plaintiffs also alleged that Cortez Pipeline Company should have used certain funds to further reduce its debt, which, in turn, would have allegedly increased the value of royalty and other payments by approximately $0.5 million. On August 7, 2006, the arbitration panel issued its opinion finding that defendants did not breach the settlement agreement. On June 21, 2007, the New Mexico federal district court entered final judgment confirming the August 7, 2006 arbitration decision.

On October 2, 2007, the plaintiffs initiated a second arbitration (*CO_2 Committee, Inc. v. Shell CO_2 Company, Ltd., aka Kinder Morgan CO_2 Company, L.P., et al.*) against Cortez Pipeline Company, Kinder Morgan CO_2 and an ExxonMobil entity. The second arbitration asserts claims similar to those asserted in the first arbitration. On April 29, 2011, the parties reached a settlement of the claims in the second arbitration. On May 5, 2011, the arbitration panel approved the settlement and issued its final award. On June 24, 2011, the New Mexico federal district court entered final judgment confirming the final arbitration award.

Colorado Severance Tax Assessment

On September 16, 2009, the Colorado Department of Revenue issued three Notices of Deficiency to Kinder Morgan CO_2. The Notices of Deficiency assessed additional state severance tax against Kinder Morgan CO_2 with respect to carbon dioxide produced from the McElmo Dome unit for tax years 2005, 2006, and 2007. The total amount of tax assessed was $5.7 million, plus interest of $1.0 million, plus penalties of $1.7 million. Kinder Morgan CO_2 protested the Notices of Deficiency and paid the tax and interest under protest. Kinder Morgan CO_2 is now awaiting the Colorado Department of Revenue's response to the protest.

Montezuma County, Colorado Property Tax Assessment

In November of 2009, the County Treasurer of Montezuma County, Colorado, issued to Kinder Morgan CO_2, as operator of the McElmo Dome unit, retroactive tax bills for tax year 2008, in the amount of $2 million. Of this amount, 37.2% is attributable to Kinder Morgan CO_2's interest. The retroactive tax bills were based on the assertion that a portion of the actual value of the carbon dioxide produced from the McElmo Dome unit was omitted from the 2008 tax roll due to an alleged over statement of transportation and other expenses used to calculate the net taxable value. Kinder Morgan CO_2 paid the retroactive tax bills under protest and will file petitions for refunds of the taxes paid under protest and will vigorously contest Montezuma County's position.

Other

In addition to the matters listed above, audits and administrative inquiries concerning Kinder Morgan CO_2's payments on carbon dioxide produced from the McElmo Dome and Bravo Dome units are currently ongoing. These audits and inquiries involve federal agencies, the states of Colorado and New Mexico, and county taxing authorities in the state of Colorado.

Commercial Litigation 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 February 2007, a trial began to determine the amount payable for easements on UPRR rights-of-way. The trial has concluded, with a decision from the judge expected by the end of 2011.

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 American Railway Engineering and Maintenance-of-Way 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.

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, and our cash flows. 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 Sparrows Point, LLC 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, cause no. WMN 09CV1668. Severstal alleges 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. Severstal seeks unspecified damages for value of the crane and lost profits. KMBT denies each of Severstal's allegations.

The Premcor Refining Group, Inc. v. Kinder Morgan Energy Partners, L.P. and Kinder Morgan Petcoke, L.P.; Arbitration in Houston, Texas

On August 12, 2010, Premcor filed a demand for arbitration against us and our subsidiary Kinder Morgan Petcoke, L.P., collectively referred to as Kinder Morgan, asserting claims for breach of contract. Kinder Morgan performs certain petroleum coke handling operations at the Port Arthur, Texas refinery that is the subject of the claim. The arbitration is being administered by the American Arbitration Association in Dallas, Texas. Premcor alleges that Kinder Morgan breached its contract with Premcor by failing to properly manage the water level in the pit of a coker unit at a refinery owned by Premcor, failing to name Premcor as an additional insured, and failing to indemnify Premcor for claims brought against Premcor by PACC. PACC is a wholly owned subsidiary of Premcor. PACC brought its claims against Premcor in a previous separate arbitration seeking to recover damages allegedly suffered by PACC when a pit wall of a coker unit collapsed at its refinery. PACC obtained an arbitration award against Premcor in the amount of $50.3 million, plus post-judgment interest. Premcor is seeking to hold Kinder Morgan liable for the award. Premcor is also seeking to recover an additional $11.4 million of alleged losses and damages in excess of the amount it owes to PACC. Premcor's claim against Kinder Morgan is based in part upon Premcor's allegation that Kinder Morgan is responsible to the extent of Kinder Morgan's alleged proportionate fault in causing the pit wall collapse. Kinder Morgan denies and is vigorously defending against all claims asserted by Premcor. The final arbitration hearing is scheduled to begin on August 29, 2011.

Mine Safety Matters

In the second quarter of 2011, our bulk terminals operations that handle coal received three citations under the Mine Safety and Health Act of 1977 which were deemed to be significant and substantial violations of mandatory health and safety standards under section 104 of the act (one of which was under section 104(d) of the act, and two orders under section 104(b) of the act). The aggregate of proposed assessments outstanding in respect of all citations received under the act in 2011, as of June 30, was $1,136. We work to promptly abate violations described in the citations. We do not believe any of such citations or the matters giving rise to such citations will have a material adverse impact on our business, financial position, results of operations or cash flows.

Employee Matters

James Lugliani vs. Kinder Morgan G.P., Inc. et al. in the Superior Court of California, Orange County

James Lugliani, a former Kinder Morgan employee, filed suit in January 2010 against various Kinder Morgan affiliates. On behalf of himself and other similarly situated current and former employees, Mr. Lugliani claims that the Kinder Morgan defendants have violated the wage and hour provisions of the California Labor Code and Business & Professions Code by failing to provide meal and rest periods; failing to pay meal and rest period premiums; failing to pay all overtime wages due; failing to timely pay wages; failing to pay wages for vacation, holidays and other paid time off; and failing to keep proper payroll records.

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.

Barstow, California

The United States Department of the Navy has alleged that historic releases of methyl tertiary-butyl ether, or MTBE, from Calnev's Barstow terminal (i) have migrated underneath the Navy's Marine Corps Logistics Base in Barstow; (ii) have impacted the Navy's existing groundwater treatment system for unrelated groundwater contamination not alleged to have been caused by Calnev; and (iii) could affect the Barstow, California Marine Corps Logistic Base's water supply system. Although Calnev believes that it has meritorious defenses to the Navy's claims, it is working with the Navy to agree upon an Administrative Settlement Agreement and Order on Consent for federal Comprehensive Environmental Response, Compensation and Liability Act (referred to as CERCLA) Removal Action to reimburse the Navy for $0.5 million in past response actions.

Westridge Release, Burnaby, British Columbia

On July 24, 2007, a third-party contractor installing a sewer line for the City of Burnaby struck a crude oil pipeline segment included within our Trans Mountain pipeline system near its Westridge terminal in Burnaby, British Columbia, resulting in a release of approximately 1,400 barrels of crude oil. The release impacted the surrounding neighborhood, several homes and nearby Burrard Inlet. No injuries were reported. To address the release, we initiated a comprehensive emergency response in collaboration with, among others, the City of Burnaby, the British Columbia Ministry of Environment, the National Energy Board (Canada), and the National Transportation Safety Board (Canada). Cleanup and environmental remediation is complete, and we have received a British Columbia Ministry of Environment Certificate of Compliance confirming complete remediation.

Kinder Morgan Canada, Inc. commenced a lawsuit against the parties it believes were responsible for the third party strike, and a number of other parties have commenced related actions. All of the outstanding litigation was settled without assignment of fault on April 8, 2011. Kinder Morgan Canada has recovered the majority of its expended costs in responding to the third party strike.

On July 22, 2009, the British Columbia Ministry of Environment issued regulatory charges against the third-party contractor, the engineering consultant to the sewer line project, Kinder Morgan Canada Inc., and our subsidiary Trans Mountain L.P. The British Columbia Ministry of Environment claims that the parties charged caused the release of crude oil, and in doing so were in violation of various sections of the Environmental, Fisheries and Migratory Bird Act. A trial has been scheduled to commence in October 2011. We are of the view that the charges have been improperly laid against us, and we are currently in discussions with the Ministry in an attempt to resolve the charges in a cooperative fashion.

Rockies Express Pipeline LLC Indiana Construction Incident

In April 2009, Randy Gardner, an employee of Sheehan Pipeline Construction Company (a third-party contractor to Rockies Express and referred to in this note as Sheehan Construction) was fatally injured during construction activities being conducted under the supervision and control of Sheehan Construction. The cause of the incident was investigated by Indiana OSHA, which issued a citation to Sheehan Construction. Rockies Express was not cited in connection with the incident.

In August 2010, the estate of Mr. Gardner filed a wrongful death action against Rockies Express and several other parties in the Superior Court of Marion County, Indiana, at case number 49D111008CT036870. The plaintiff alleges that the defendants were negligent in allegedly failing to provide a safe worksite, and seeks unspecified compensatory damages. Rockies Express denies that it was in any way negligent or otherwise responsible for this incident, and intends to assert contractual claims for complete indemnification for any and all costs arising from this incident, including any costs related to this lawsuit, against third parties and their insurers.

Perth Amboy, New Jersey Tank Release

In May 2011, the PHMSA issued a Notice of Probable Violation, Proposed Civil Penalty and Proposed Compliance Order, or NOPV, to KMLT. The notice alleges violations of PHMSA's regulations related to an October 28, 2009 tank release from our Perth Amboy, New Jersey liquids terminal. No product left the company's property, and additionally, there were no injuries, no impact to the adjacent community or public, and no fire as a result of the release. The notice proposes a penalty in the amount of $425,000. We are cooperating fully with the PHMSA on the response and remediation of this issue.

Central Florida Pipeline Release, Tampa, Florida

On July 22, 2011, our subsidiary Central Florida Pipeline LLC reported a refined petroleum products release on a section of its 10-inch diameter pipeline near Tampa, Florida. The pipeline carries jet fuel and diesel to Orlando and was carrying jet fuel at the time of the incident. There was no fire and no injuries associated with the incident. We immediately began clean up operations in coordination with federal, state and local agencies. The cause of the incident is under investigation.

General

Although no assurance can be given, we believe that we have meritorious defenses to the actions set forth in this note and, to the extent an assessment of the matter is reasonably possible, if it is probable that a liability has been incurred and the amount of loss can be reasonably estimated, we believe that we have established an adequate reserve to cover potential liability.

Additionally, although it is not possible to predict the ultimate outcomes, we also believe, based on our experiences to date and the reserves we have established, that the ultimate resolution of these matters will not have a material adverse impact on our business, financial position, results of operations or distributions to limited partners. As of June 30, 2011 and December 31, 2010, we have recorded a total reserve for legal fees, transportation rate cases and other litigation liabilities in the amount of $268.1 million and $169.8 million, respectively. The reserve is primarily related to various claims from regulatory proceedings arising from our West Coast products pipeline transportation rates, and the contingent amount is based on both the circumstances of probability and reasonability of dollar estimates. The overall change in the reserve from December 31, 2010 includes both a $63.0 million payment (for transportation rate settlements on our Pacific operations' pipelines) in March 2011 that reduced the liability, and a $165.0 million increase in expense in June 2011, which increased the liability. The June 2011 increase to the reserve was related to various claims from regulatory proceedings arising from our West Coast products pipeline transportation rates, and the contingent amount is based on both the circumstances of probability and reasonability of dollar estimates. We regularly assess the likelihood of adverse outcomes resulting from these claims in order to determine the adequacy of our liability provision.

Environmental Matters

Casper and Douglas, EPA Notice of Violation

In March 2011, the EPA conducted inspections of several environmental programs at the Douglas and Casper Gas Plants in Wyoming. In June 2011, we received two letters from the EPA alleging violations at both gas plants of the Risk Management Program requirements under the Clean Air Act. We are cooperating with the EPA and working with the EPA to resolve these allegations.

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 through the end of 2010. A hearing was held on December 13, 2010 to hear the City's motion to remove the litigation stay. At the hearing, the judge denied the motion to lift the stay without prejudice. At the next case management conference held on June 13, 2011, the judge again continued the full litigation stay. During the stay, the parties deemed responsible by the local regulatory agency have worked with that agency concerning the scope of the required cleanup and are now starting a sampling and testing program at the site. The local regulatory agency issued specific cleanup goals in early 2010, and two of those parties, including KMLT, have appealed those cleanup goals to the state water board. The state water board has not yet taken any action with regard to our appeal petitions.

Plaintiff's Third Amended Complaint alleges that future environmental cleanup costs at the former terminal will exceed $10 million, and that the plaintiff's past damages exceed $2 million. No trial date has yet been set.

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

On April 23, 2003, Exxon Mobil Corporation 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.

The complaint seeks any and all damages related to remediating all environmental contamination at the terminal, and, according to the New Jersey Spill Compensation and Control Act, treble damages may be available for actual dollars incorrectly spent by the successful party in the lawsuit. The parties engaged in court ordered mediation in 2008 through 2009, which did not result in settlement. The trial judge has issued a Case Management Order and the parties are actively engaged in discovery.

On June 25, 2007, the New Jersey Department of Environmental Protection, 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 Corporation 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 seeking to bring Support Terminals/Plains into the case. Support Terminals/Plains filed motions to dismiss the third party complaints, which were denied. Support Terminals/Plains is now joined in the case, and it filed an Answer denying all claims. The court has consolidated the two cases. All private parties and the state participated in two mediation conferences in 2010.

In December 2010, KMLT and Plains Products entered into an agreement in principle with the New Jersey Department of Environmental Protection for settlement of the state's alleged natural resource damages claim. The parties then entered into a Consent Judgment which was subject to public notice and comment and court approval. The natural resource damage settlement includes a monetary award of $1.1 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 parties' relative share of responsibility (50/50) to the NJDEP under the Consent Judgment noted above. The Consent Judgment is now before the court. Soon after filing the Consent Judgment, Exxon Mobil filed an opposition to the Consent Judgment to the court. The parties now have until August 19, 2011 to brief the issues and participate in an oral hearing on the matter. The settlement with the state does not resolve the original complaint brought by Exxon Mobil. There is no trial date set.

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 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.

The Court issued a Case Management Order on January 6, 2011, setting dates for completion of discovery and setting a trial date. In April, 2011, the parties filed a joint stipulation to extend the discovery schedule by approximately 3 months. Now, the parties must complete all fact discovery by January 23, 2012. A mandatory settlement conference is now set for November 2, 2011 and the trial is set for September 25, 2012. We have been and will continue to aggressively defend this action. This site has been, and currently is, under the regulatory oversight and order of the California Regional Water Quality Control Board. We continue to be in compliance with this agency order as we conduct an extensive remediation effort at the City's stadium property site.

Kinder Morgan, EPA Section 114 Information Request

On January 8, 2010, Kinder Morgan Inc., on behalf of Natural Gas Pipeline Company of America LLC, Horizon Pipeline Company and Rockies Express Pipeline LLC, received a Clean Air Act Section 114 information request from the U.S. Environmental Protection Agency, Region V. This information request requires that the three affiliated companies provide the EPA with air permit and various other information related to their natural gas pipeline compressor station operations in Illinois, Indiana, and Ohio. The affiliated companies have responded to the request and believe the relevant natural gas compressor station operations are in substantial compliance with applicable air quality laws and regulations.

Notice of Proposed Debarment

In April 2011, we received Notices of Proposed Debarment from the United States Environmental Protection Agency's Suspension and Debarment Division, referred to in this Note as the EPA SDD. The Notices propose the debarment of Kinder Morgan Energy Partners, L.P., Kinder Morgan, Inc., Kinder Morgan G.P., Inc., and Kinder Morgan Management, LLC, along with four of our subsidiaries, from participation in future federal contracting and assistance activities. The Notices allege that certain of the respondents' past environmental violations indicate a lack of present responsibility warranting debarment. Our objective is to fully comply with all applicable legal requirements and to operate our assets in accordance with our processes, procedures and compliance plans. We are performing better than industry averages in our incident rates and in our safety performance, all of which is publicly reported on our website. We take environmental compliance very seriously, and look forward to demonstrating our present responsibility to the EPA SDD through this administrative process and we are engaged in discussions with EPA SDD with the goal of resolving this matter in a cooperative fashion. We do not anticipate that the resolution of this matter will have a material adverse impact on our business, financial position, results of operations or cash flows.

Other Environmental

We are subject to environmental cleanup and enforcement actions from time to time. In particular, the 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 negotiate and settle these matters. We do not believe that these alleged violations will have a material adverse effect on our business, financial position, results of operations or cash flows.

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. See "—Pipeline Integrity and Releases" above for additional information with respect to ruptures and leaks from our pipelines.

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 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 settlements of these claims will occur, and changing circumstances could cause these matters to have a material adverse impact. As of June 30, 2011, we have accrued an environmental reserve of $73.5 million, and we believe that these pending environmental matters will not have a material adverse impact on our business, cash flows, financial position or results of operations. In addition, as of June 30, 2011, we have recorded a receivable of $6.5 million for expected cost recoveries that have been deemed probable. As of December 31, 2010, our environmental reserve totaled $74.7 million and our estimated receivable for environmental cost recoveries totaled $8.6 million. 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.

Other

We are a defendant in various lawsuits arising from the day-to-day operations of our businesses. 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 cash flows.

11. Regulatory Matters

Kinder Morgan Interstate Gas Transmission Pipeline – Franklin to Hastings Expansion Project

KMIGT has filed a prior notice request to expand and replace certain mainline pipeline facilities to create up to 10,000 dekatherms per day of firm transportation capacity to serve an ethanol plant located near Aurora, Nebraska. The estimated cost of the facilities is $18.4 million. The project was constructed and went into service on April 14, 2011.

FERC Natural Gas Fuel Tracker Proceedings

Trailblazer Pipeline Company LLC

On April 28, 2011, the FERC issued an Order Rejecting Tariff Record and Denying Waiver in Trailblazer Pipeline Company LLC's annual fuel tracker filing at Docket No. RP11-1939-000. The order requires Trailblazer to make a compliance filing for its annual Expansion Fuel Adjustment Percentage (EFAP) pursuant to its tariff. In its previous two annual tracker filings, Trailblazer received authorization by the FERC to defer collection of its fuel deferred account until a future period by granting a waiver of various fuel tracker provisions. In the Docket No. RP11-1939 filing, Trailblazer again asked for tariff waivers that would defer the collection of its fuel deferred account to a future period, which the FERC denied. Trailblazer has filed for rehearing of the FERC's April 28, 2011 order, which is pending before the FERC.

On May 2, 2011, Trailblazer filed to re-determine its EFAP in compliance with the April 28, 2011 order, implementing a revised EFAP rate of 8.14%, which included the proposed recovery of the deferred account. On May 18, 2011, the FERC issued an order rejecting the May 2, 2011 filing, on the basis that the filing to implement a revised EFAP must be accomplished as a new proceeding, not as a compliance filing. Trailblazer has filed for rehearing of the May 18, 2011 order, which is also pending before the FERC.

On June 3, 2011, Trailblazer filed in a new proceeding, Docket No. RP11-2168-000, revised tariff records to redetermine its EFAP, with a proposed effective date of July 1, 2011. Trailblazer included three EFAP rate options. In addition, under two of the options, Trailblazer proposed to continue to defer collection of the deferred account until a future date. In an order dated July 1, 2011, referred to in this Note as the July 1 Order, the FERC rejected the two options to defer recovery of the deferred account and accepted the option that included recovery of the entire deferred account. Specifically, the FERC approved an EFAP rate of 8.69%, subject to refund, effective July 1, 2011 and established hearing proceedings to determine the appropriate throughput, revenue and cost data to use for determining the EFAP and the composition, accounting and proposed recovery methodology for amounts in the deferred account. In the July 1 Order, the FERC determined that Trailblazer could not charge negotiated rate shippers a fuel rate above the caps established in their negotiated rate agreements with Trailblazer and that operation of the cap was not an issue for hearing. As a result of this determination, Trailblazer recognized a $13.1 million operating expense in the second quarter of 2011 for the amount of the deferred costs that is potentially attributable to the negotiated rate shippers. Trailblazer has sought rehearing of the July 1 Order.

A prehearing conference was held on July 14, 2011, and a procedural schedule that results in a hearing in April 2012 was established.

Rockies Express Pipeline LLC

On March 1, 2011, Rockies Express Pipeline LLC made its annual filing to revise its fuel lost and unaccounted for percentage, referred to as its FL&U rate, applicable to its shippers effective April 1, 2011. In this filing, Rockies Express requested an increase in its FL&U rate due to a decline in the price of natural gas used to index its FL&U rate that had resulted in a fuel tracker receivable balance as of December 31, 2010. Rockies Express proposed two options to allow it to recover these costs.

On March 30, 2011, the FERC notified Rockies Express that it had rejected the first option and that the second option, while accepted effective April 1, 2011, was under further FERC review. This event caused Rockies Express to reconsider the recoverability of a portion of its fuel tracker receivable balance that would have been recovered from one shipper. Therefore, in the first quarter of 2011, Rockies Express reduced its fuel tracker receivable balance by $8.2 million and recorded the same amount as additional operations and maintenance expense.

12. Recent Accounting Pronouncements

Accounting Standards Updates

None of the Accounting Standards Updates (ASU) that we adopted and that became effective January 1, 2011 had a material impact on our consolidated financial statements.

ASU No. 2011-04

On May 12, 2011, the Financial Accounting Standards Board (FASB) issued ASU No. 2011-04, "Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs." This ASU amends U.S. generally accepted accounting principles (GAAP) and results in a consistent definition of fair value and common requirements for measurement of and disclosure about fair value between U.S. GAAP and international financial reporting standards (IFRS). The amendments in this ASU change the wording used to describe many of the requirements in U.S. GAAP for measuring fair value and for disclosing information about fair value measurements; however, the amendment's requirements do not extend the use of fair value accounting, and for many of the requirements, the FASB does not intend for the amendments to result in a change in the application of the requirements in the "Fair Value Measurement" Topic of the Codification. Additionally, ASU No. 2011-04 includes some enhanced disclosure requirements, including an expansion of the information required for Level 3 fair value measurements. ASU No. 2011-04 is effective for interim and annual periods beginning on or after December 15, 2011 (January 1, 2012 for us). The amendments in this ASU are to be applied prospectively, and early adoption is prohibited. We are currently reviewing the effects of ASU No. 2011-04.

ASU No. 2011-05

On June 16, 2011, the FASB issued ASU No. 2011-05, "Presentation of Comprehensive Income." This ASU eliminates the current option to report other comprehensive income and its components in the statement of changes in equity (statement of partners' capital for us). An entity can elect to present items of net income and other comprehensive income in one continuous statement or in two separate, but consecutive, statements. ASU No. 2011-05 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011 (January 1, 2012 for us) and interim and annual periods thereafter. Early adoption is permitted, and full retrospective application is required. Since this ASU pertains to disclosure requirements only, the adoption of this ASU will not have a material impact on our consolidated financial statements.

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

General and Basis of Presentation

The following information 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 2010 Form 10-K/A; and (iii) our management's discussion and analysis of financial condition and results of operations included in our 2010 Form 10-K.

As an energy infrastructure owner and operator in multiple facets of the United States' and Canada's various energy businesses and markets, we examine a number of variables and factors on a routine basis to evaluate our current performance and our prospects for the future. Many of our operations are regulated by various U.S. and Canadian regulatory bodies and a portion of our business portfolio (including our Kinder Morgan Canada business segment, the Canadian portion of our Cochin Pipeline, and our bulk and liquids terminal facilities located in Canada) uses the local Canadian dollar as the functional currency for its Canadian operations and enters into foreign currency-based transactions, both of which affect segment results due to the inherent variability in U.S: Canadian dollar exchange rates. To help understand our reported operating results, all of the following references to "foreign currency effects" or similar terms in this section represent our estimates of the changes in financial results, in U.S. dollars, resulting from fluctuations in the relative value of the Canadian dollar to the U.S. dollar. The references are made to facilitate period-to-period comparisons of business performance and may not be comparable to similarly titled measures used by other registrants.

The profitability of our refined petroleum products pipeline transportation business is generally driven by the volume of refined petroleum products that we transport and the prices we receive for our services. Transportation volume levels are primarily driven by the demand for the refined petroleum products being shipped or stored. Demand for refined petroleum products tends to track in large measure demographic and economic growth, and with the exception of periods of time with very high product prices or recessionary conditions, demand tends to be relatively stable. Because of that, we seek to own refined petroleum products pipelines located in, or that transport to, stable or growing markets and population centers. The prices for shipping are generally based on regulated tariffs that are adjusted annually based on changes in the U.S. Producer Price Index.

With respect to our interstate natural gas pipelines and related storage facilities, the revenues from these assets are primarily received under contracts with terms that are fixed for various and extended periods of time. To the extent practicable and economically feasible in light of our strategic plans and other factors, we generally attempt to mitigate risk of reduced volumes and prices by negotiating contracts with longer terms, with higher per-unit pricing and for a greater percentage of our available capacity. These long-term contracts are typically structured with a fixed-fee reserving the right to transport natural gas and specify that we receive the majority of our fee for making the capacity available, whether or not the customer actually chooses to utilize the capacity. Similarly, in our Texas Intrastate Pipeline business, we have long-term transport and sales requirements with minimum volume payment obligations which secure approximately 75% of our sales and transport margins in that business. Therefore, where we have long-term contracts, we are not exposed to short-term changes in commodity supply or demand. However, as contracts expire, we do have exposure to the longer term trends in supply and demand for natural gas. As of December 31, 2010, the remaining average contract life of our natural gas transportation contracts (including our intrastate pipelines) was approximately nine years.

Our CO_2 sales and transportation business primarily has contracts with minimum volume requirements, which as of December 31, 2010, had a remaining average contract life of 4.7 years. Carbon dioxide sales contracts vary from customer to customer and have evolved over time as supply and demand conditions have changed. Older contracts have had a fixed price component and a variable price component typically tied to the price of crude oil. More recent contracts have provided for a delivered price tied to the price of crude oil, but with a floor price. On a volume-weighted basis, for contracts making deliveries in 2011, and utilizing the average oil price per barrel contained in our 2011 budget, approximately 76% of our contractual volumes are based on a fixed fee or floor price, and 24% fluctuates with the price of oil. In the long-term, our success in this business is driven by the demand for carbon dioxide. However, short-term changes in the demand for carbon dioxide typically do not have a significant impact on us due to the required minimum sales volumes under many of our contracts. In our CO_2 segment's oil and gas producing activities, we monitor the amount of capital we expend in relation to the amount of production that we expect to add. In that regard, our production during any period is an important measure. In addition, the revenues we receive from our crude oil, natural gas liquids and carbon dioxide sales are affected by the prices we realize from the sale of these products. Over the long-term, we will tend to receive prices that are dictated by the demand and overall market price for these products. In the shorter term, however, market prices are likely not indicative of the revenues we will receive due to our risk management, or hedging, program, in which the prices to be realized for certain of our future sales quantities are fixed, capped or bracketed through the use of financial derivative contracts, particularly for crude oil. Our realized weighted average crude oil price per barrel, with all hedges allocated to oil, was $69.37 and $69.07 per barrel in the second quarter and first six months of 2011, respectively, and $59.58 and $60.05 per barrel in the second quarter and first six months of 2010, respectively. Had we not used energy derivative contracts to transfer commodity price risk, our crude oil sales prices would have averaged $99.83 and $95.29 per barrel in the second quarter and first six months of 2011, respectively, and $75.17 and $75.80 per barrel in the second quarter and first six months of 2010 respectively.

The factors impacting our Terminals business segment generally differ depending on whether the terminal is a liquids or bulk terminal, and in the case of a bulk terminal, the type of product being handled or stored. As with our refined petroleum products pipeline transportation business, the revenues from our bulk terminals business are generally driven by the volumes we handle and/or store, as well as the prices we receive for our services, which in turn are driven by the demand for the products being shipped or stored. While we handle and store a large variety of products in our bulk terminals, the primary products are coal, petroleum coke, and steel. For the most part, we have contracts for this business that have minimum volume guarantees and are volume based above the minimums. Because these contracts are volume based above the minimums, our profitability from the bulk business can be sensitive to economic conditions. Our liquids terminals business generally has longer-term contracts that require the customer to pay regardless of whether they use the capacity. Thus, similar to our natural gas pipeline business, our liquids terminals business is less sensitive to short-term changes in supply and demand. Therefore, the extent to which changes in these variables affect our terminals business in the near term is a function of the length of the underlying service contracts (which is typically approximately three to four years), the extent to which revenues under the contracts are a function of the amount of product stored or transported, and the extent to which such contracts expire during any given period of time. To the extent practicable and economically feasible in light of our strategic plans and other factors, we generally attempt to mitigate the risk of reduced volumes and pricing by negotiating contracts with longer terms, with higher per-unit pricing and for a greater percentage of our available capacity. In addition, weather-related factors such as hurricanes, floods and droughts may impact our facilities and access to them and, thus, the profitability of certain terminals for limited periods of time or, in relatively rare cases of severe damage to facilities, for longer periods.

In our discussions of the operating results of individual businesses that follow (see "—Results of Operations" below), 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. Continuing our history of making accretive acquisitions and economically advantageous expansions of existing businesses, in the full year 2010, we invested approximately $2.5 billion for both strategic business acquisitions and expansions of existing assets, and these capital investments helped us to achieve compound annual growth rates in cash distributions to our limited partners of 4.8%, 8.1%, and 7.0%, respectively, for the one-year, three-year, and five-year periods ended December 31, 2010.

Thus, the amount that we are able to increase distributions to our unitholders will, to some extent, be a function of our ability to complete successful acquisitions and expansions. We believe we will continue to have opportunities for expansion of our facilities in many markets, and we currently estimate spending approximately $2.5 billion for our 2011 capital expansion program, including acquisitions and investment contributions (in July 2011, we acquired the remaining 50% interest in KinderHawk Field Services LLC that we did not already own and a 25% interest in EagleHawk Field Services LLC for an aggregate consideration of $911.9 million). Based on our historical record and because there is continued demand for energy infrastructure in the areas we serve, we expect to continue to have such opportunities in the future, although the level of such opportunities is difficult to predict.

Our ability to make accretive acquisitions is a function of the availability of suitable acquisition candidates at the right cost, and 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.

In addition, our ability to make accretive acquisitions or expand our assets is impacted by our ability to maintain adequate liquidity and to raise the necessary capital needed to fund such acquisitions. As a master limited partnership, we distribute all of our available cash 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. For a further discussion of our liquidity, including our public debt and equity offerings in the first half of 2011, please see "—Financial Condition" below.

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 generally accepted accounting principles in the United States 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, 2011. Our goodwill impairment analysis performed on that date did not result in an impairment charge, and previous or 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. For more information on our goodwill impairment analysis, see Note 3 "Intangibles—Goodwill" to our consolidated financial statements included elsewhere in this report.

Further information about us and information regarding our accounting policies and estimates that we consider to be "critical" can be found in our 2010 Form 10-K. There have not been any significant changes in these policies and estimates during the six months ended June 30, 2011.

Results of Operations

Consolidated

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Earnings increase/(decrease)	
	(In millions, except percentages)			
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments(a)				
Products Pipelines(b)	$ 20.7	$ 165.2	$ (144.5)	(87)%
Natural Gas Pipelines(c)	181.3	185.0	(3.7)	(2)%
CO_2(d)	266.4	249.4	17.0	7 %
Terminals(e)	170.3	165.5	4.8	3 %
Kinder Morgan Canada(f)	53.6	43.9	9.7	22 %
Segment earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	692.3	809.0	(116.7)	(14)%
Depreciation, depletion and amortization expense	(229.4)	(223.2)	(6.2)	(3)%
Amortization of excess cost of equity investments	(1.6)	(1.5)	(0.1)	(7)%
General and administrative expense(g)	(97.4)	(93.4)	(4.0)	(4)%
Unallocable interest expense, net of interest income(h)	(129.6)	(123.8)	(5.8)	(5)%
Unallocable income tax expense	(2.4)	(2.0)	(0.4)	(20)%
Net income	231.9	365.1	(133.2)	(36)%
Net income attributable to noncontrolling interests(i)	(1.4)	(3.9)	2.5	64 %
Net income attributable to Kinder Morgan Energy Partners, L.P.	$ 230.5	$ 361.2	$ (130.7)	(36)%

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010	Earnings increase/(decrease)	
	(In millions, except percentages)			
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments(a)				
Products Pipelines(j)	$ 201.2	$ 171.6	$ 29.6	17 %
Natural Gas Pipelines(k)	403.9	405.6	(1.7)	-
CO_2(l)	528.4	502.6	25.8	5 %
Terminals(m)	344.7	316.0	28.7	9 %
Kinder Morgan Canada(f)	101.5	88.9	12.6	14 %
Segment earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	1,579.7	1,484.7	95.0	6 %
Depreciation, depletion and amortization expense	(451.2)	(450.5)	(0.7)	-
Amortization of excess cost of equity investments	(3.1)	(2.9)	(0.2)	(7)%
General and administrative expense(n)	(286.6)	(194.5)	(92.1)	(47)%
Unallocable interest expense, net of interest income(o)	(261.3)	(240.1)	(21.2)	(9)%
Unallocable income tax expense	(4.7)	(4.2)	(0.5)	(12)%
Net income	572.8	592.5	(19.7)	(3)%
Net income attributable to noncontrolling interests(p)	(4.5)	(6.0)	1.5	25 %
Net income attributable to Kinder Morgan Energy Partners, L.P.	$ 568.3	$ 586.5	$ (18.2)	(3)%

(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) 2011 amount includes a $165.0 million increase in expense associated with rate case liability adjustments, a $10.8 million increase in income from the sale of a portion of our Gaffey Street, California land, and a $0.1 million decrease in expense (reflecting tax savings) related to non-cash compensation expense allocated to us from KMI (we do not have any obligation, nor do we expect to pay any amounts or realize any direct benefits related to this expense). 2010 amount includes a $15.5 million decrease in income associated with combined property environmental expenses and disposal losses related to the demolition of physical assets in preparation for the sale of our Gaffey Street, California land, and a $0.4 million decrease in income resulting from unrealized foreign currency losses on long-term debt transactions.

(c) 2011 amount includes a $9.7 million increase in expense from the write-off of a receivable for fuel under-collected prior to 2011. 2010 amount includes a $0.1 million decrease in income from unrealized losses on derivative contracts used to hedge forecasted natural gas sales.

(d) 2011 and 2010 amounts include a decrease in income of $1.8 million and an increase in income of $7.9 million, respectively, from unrealized gains and losses on derivative contracts used to hedge forecasted crude oil sales.

(e) 2011 amount includes (i) a $4.3 million casualty indemnification gain related to a 2008 fire at our Pasadena, Texas liquids terminal; (ii) a $2.2 million increase in income associated with the sale of a 51% ownership interest in two of our subsidiaries: River Consulting LLC and Devco USA L.L.C.; (iii) a $0.2 million decrease in expense (reflecting tax savings) related to non-cash compensation expense allocated to us from KMI (we do not have any obligation, nor do we expect to pay any amounts or realize any direct benefits related to this expense); (iv) a $1.2 million increase in expense associated with environmental liability adjustments; and (v) a $1.2 million decrease in income from casualty insurance deductibles and the write-off of assets related to casualty losses. 2010 amount includes a $6.7 million casualty indemnification gain related to a 2008 fire at our Pasadena, Texas liquids terminal, and a $0.2 million increase in expense related to storm and flood clean-up and repair activities.

(f) 2011 amount includes a $2.2 million decrease in expense (reflecting tax savings) related to non-cash compensation expense allocated to us from KMI (we do not have any obligation, nor do we expect to pay any amounts or realize any direct benefits related to this expense).

(g) 2011 amount includes (i) a $1.4 million increase in unallocated payroll tax expense (related to the $87.1 million special non-cash bonus expense to non-senior management employees allocated to us from KMI in the first quarter of 2011; however, we do not have any obligation, nor do we expect to pay any amounts related to this expense); (ii) a $0.6 million increase in expense for certain asset and business acquisition costs; and (iii) a $0.1 million decrease in expense related to capitalized overhead costs associated with the 2008 hurricane season. 2010 amount includes (i) a $1.3 million increase in non-cash compensation expense allocated to us from KMI (we do not have any obligation, nor do we expect to pay any amounts related to this expense); (ii) a $1.0 million increase in expense for certain asset and business acquisition costs; and (iii) a $0.1 million increase in expense related to capitalized overhead costs associated with the 2008 hurricane season.

(h) 2011 and 2010 amounts include increases in imputed interest expense of $0.2 million and $0.2 million, respectively, related to our January 1, 2007 Cochin Pipeline acquisition.

(i) 2011 and 2010 amounts include decreases of $2.4 million and $0.1 million, respectively, in net income attributable to our noncontrolling interests, related to the combined effect from all of the three month 2011 and 2010 items previously disclosed in these footnotes.

(j) 2011 and 2010 amounts include increases in income of $0.2 million and $0.1 million, respectively, resulting from unrealized foreign currency gains on long-term debt transactions. 2011 amount also includes a $165.0 million increase in expense associated with rate case liability adjustments, a $10.8 million increase in income from the sale of a portion of our Gaffey Street, California land, and a $0.1 million decrease in expense (reflecting tax savings) related to non-cash compensation expense allocated to us from KMI (we do not have any obligation, nor do we expect to pay any amounts or realize any direct benefits related to this expense). 2010 amount also includes a $158.0 million increase in expense associated with rate case liability adjustments, and a $15.5 million decrease in income associated with combined property environmental expenses and disposal losses related to the demolition of physical assets in preparation for the sale of our Gaffey Street, California land.

(k) 2011 amount includes a $9.7 million increase in expense from the write-off of a receivable for fuel under-collected prior to 2011. 2010 amount includes a $0.8 million increase in income from unrealized gains on derivative contracts used to hedge forecasted natural gas sales, and a $0.4 million increase in income from certain measurement period adjustments related to our October 1, 2009 natural gas treating business acquisition.

(l) 2011 and 2010 amounts include increases in income of $1.9 million and $13.3 million, respectively, from unrealized gains on derivative contracts used to hedge forecasted crude oil sales.

(m) 2011 amount includes (i) a $4.7 million decrease in expense (reflecting tax savings) related to non-cash compensation expense allocated to us from KMI (we do not have any obligation, nor do we expect to pay any amounts or realize any direct benefits related to this expense); (ii) a $4.3 million casualty indemnification gain related to a 2008 fire at our Pasadena, Texas liquids terminal; (iii) a $2.2 million increase in income associated with the sale of a 51% ownership interest in two of our subsidiaries: River Consulting LLC and Devco USA L.L.C.; (iv) a $2.2 million increase in income from adjustments associated with the sale of our ownership interest in the boat fleeting business we acquired from Megafleet Towing Co., Inc. in April 2009; (v) a $3.2 million decrease in income from casualty insurance deductibles and the write-off of assets related to casualty losses; (vi) a $1.2 million increase in expense associated with environmental liability adjustments; and (vii) a $0.6 million increase in expense associated with the settlement of a litigation matter at our Carteret, New Jersey liquids terminal. 2010 amount includes a $6.7 million casualty indemnification gain related to a 2008 fire at our Pasadena, Texas liquids terminal, and a $0.6 million increase in expense related to storm and flood clean-up and repair activities.

(n) 2011 amount includes (i) a combined $89.9 million increase in non-cash compensation expense (including $87.1 million related to a special bonus expense to non-senior management employees), allocated to us from KMI; however, we do not have any obligation, nor do we expect to pay any amounts related to this expense; (ii) a $1.4 million increase in unallocated payroll tax expense (related to the $87.1 million special bonus expense allocated to us from KMI); (iii) a $1.1 million increase in expense for certain asset and business acquisition costs; and (iv) a $0.1 million decrease in expense related to capitalized overhead costs associated with the 2008 hurricane season. 2010 amount includes (i) a $2.7 million increase in non-cash compensation expense allocated to us from KMI (we do not have any obligation, nor do we expect to pay any amounts related to this expense); (ii) a $2.4 million increase in expense for certain asset and business acquisition costs; (iii) a $1.6 million increase in legal expense associated with items disclosed in these footnotes such as legal settlements and pipeline failures; and (iv) a $0.2 million decrease in expense related to capitalized overhead costs associated with the 2008 hurricane season.

(o) 2011 and 2010 amounts include increases in imputed interest expense of $0.4 million and $0.6 million, respectively, related to our January 1, 2007 Cochin Pipeline acquisition.

(p) 2011 and 2010 amounts include decreases of $3.5 million and $2.4 million, respectively, in net income attributable to our noncontrolling interests, related to the combined effect from all of the six month 2011 and 2010 items previously disclosed in these footnotes.

For the quarterly period ended June 30, 2011, net income attributable to our partners (which includes all of our limited partner unitholders and our general partner) totaled $230.5 million. For the same quarter in 2010, net income attributable to our partners totaled $361.2 million. Total revenues for the comparative second quarter periods were $2,019.3 million in 2011 and $1,961.5 million in 2010. For the six months ended June 30, 2011 and 2010, net income attributable to our partners totaled $568.3 million and $586.5 million, respectively, on revenues of $4,012.1 million and $4,091.1 million, respectively.

Because 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), we consider each period’s earnings before all non-cash depreciation, depletion and amortization expenses, including amortization of excess cost of equity investments, to be an important measure of our success in maximizing returns to our partners. We also use segment earnings before depreciation, depletion and amortization expenses (defined in the table above and sometimes referred to in this report as 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.

Compared to the second quarter of 2010, total segment earnings before depreciation, depletion and amortization decreased $116.7 million (14%) in the second quarter of 2011; however, this overall decrease in earnings included a $157.5 million decrease in earnings from the effect of the certain items described in the footnotes to the tables above (which combined to decrease total segment EBDA by $159.1 million in the second quarter of 2011 and to decrease total segment EBDA by $1.6 million in the second quarter of 2010). The remaining $40.8 million (5%) increase in quarterly segment earnings before depreciation, depletion and amortization included higher earnings in 2011 from our CO_2, Kinder Morgan Canada, Terminals, and Natural Gas Pipelines business segments, partially offset with lower earnings from our Products Pipelines business segment.

For the comparable six month periods, total segment earnings before depreciation, depletion and amortization expenses increased $95.0 million (6%) in 2011; however, this overall increase in earnings included an increase of $1.7 million from the effect of the certain items described in the footnotes to the table above (which combined to decrease total segment EBDA by $151.1 million in the first half of 2011 and to decrease total segment EBDA by $152.8 million in the first half of 2010). The remaining $93.3 million (6%) increase in quarterly segment earnings before depreciation, depletion and amortization resulted from better performance from all five of our reportable business segments, mainly due to increases attributable to our CO_2 and Terminals business segments.

Products Pipelines

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(In millions, except operating statistics)			
Revenues	$ 227.4	$ 226.3	$ 453.0	$ 433.8
Operating expenses(a)	(226.7)	(65.0)	(279.0)	(273.9)
Other income (expense)(b)	10.5	(3.9)	10.6	(3.9)
Earnings from equity investments	11.9	8.8	22.8	14.6
Interest income and Other, net(c)	2.2	1.3	3.5	3.9
Income tax expense(d)	(4.6)	(2.3)	(9.7)	(2.9)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 20.7	$ 165.2	$ 201.2	$ 171.6
Gasoline (MMBbl)(e)	99.6	103.4	195.5	197.2
Diesel fuel (MMBbl)	36.9	38.3	73.5	71.1
Jet fuel (MMBbl)	29.2	26.2	54.8	51.0
Total refined product volumes (MMBbl)	165.7	167.9	323.8	319.3
Natural gas liquids (MMBbl)	5.6	5.7	12.2	11.6
Total delivery volumes (MMBbl)(f)	171.3	173.6	336.0	330.9
Ethanol (MMBbl)(g)	7.7	7.6	15.0	14.8

(a) Three and six month 2011 amounts include a $165.0 million increase in expense associated with rate case liability adjustments. Three and six month 2010 amounts include an $11.6 million increase in property environmental expenses related to the demolition of physical assets in preparation for the sale of our Gaffey Street, California land. Six month 2010 amount also includes a $158.0 million increase in expense associated with rate case liability adjustments.

(b) Three and six month 2011 amounts include a $10.8 million increase in income from the sale of a portion of our Gaffey Street, California land. Three and six month 2010 amounts include property disposal losses of $3.9 million related to the demolition of physical assets in preparation for the sale of our Gaffey Street, California land.

(c) Six month 2011 amount includes a $0.2 million increase in income, and the three and six month 2010 amounts include a $0.4 million decrease in income and a $0.1 million increase in income, respectively, all resulting from unrealized foreign currency gains and losses on long-term debt transactions.

(d) Three and six month 2011 amounts include a $0.1 million decrease in expense (reflecting tax savings) related to non-cash compensation expense allocated to us from KMI (we do not have any obligation, nor do we expect to pay any amounts or realize any direct benefits related to this expense).

(e) Volumes include ethanol pipeline volumes.

(f) Includes Pacific, Plantation, Calnev, Central Florida, Cochin and Cypress pipeline volumes.

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

Combined, the certain items described in the footnotes to the table above decreased the change in our Product Pipelines' earnings before depreciation, depletion and amortization expenses by $138.2 million in the second quarter of 2011, and increased the change in earnings before depreciation, depletion and amortization expenses by $19.5 million in the first six months of 2011, when compared to the same periods of 2010. Following is information, for each of the comparable three and six month periods of 2011 and 2010, related to the segment's (i) remaining $6.3 million (4%) decrease and $10.1 million (3%) increase in earnings before depreciation, depletion and amortization; and (ii) $1.1 million (0%) and $19.2 million (4%) increases in operating revenues:

Three months ended June 30, 2011 versus Three months ended June 30, 2010

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Cochin Pipeline	$ 3.1	69 %	$ 2.2	23 %
West Coast Terminals	1.9	10 %	3.1	12 %
Plantation Pipeline	0.8	7 %	0.3	5 %
Pacific operations	0.1	-	(1.3)	(1)%
Southeast Terminals	(4.7)	(22)%	(0.5)	(2)%
Central Florida Pipeline	(3.3)	(20)%	(0.9)	(5)%
Calnev Pipeline	(1.4)	(10)%	(2.0)	(10)%
All others (including eliminations)	(2.8)	(23)%	0.2	1 %
Total Products Pipelines	$ (6.3)	(4)%	$ 1.1	-

Six months ended June 30, 2011 versus Six months ended June 30, 2010

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Cochin Pipeline	$ 10.1	76 %	$ 11.9	60 %
Pacific operations	4.4	3 %	0.8	-
West Coast Terminals	3.9	10 %	6.1	13 %
Plantation Pipeline	3.3	15 %	0.3	3 %
Central Florida Pipeline	(4.4)	(15)%	(0.8)	(2)%
Calnev Pipeline	(3.2)	(11)%	(3.2)	(9)%
Southeast Terminals	(2.0)	(5)%	3.5	7 %
All others (including eliminations)	(2.0)	(9)%	0.6	2 %
Total Products Pipelines	$ 10.1	3 %	$ 19.2	4 %

The primary increases and decreases in our Products Pipelines business segment's earnings before depreciation, depletion and amortization expenses in the comparable three and six month periods of 2011 and 2010 included the following:

- increases of $3.1 million (69%) and $10.1 million (76%), respectively, due to higher earnings from our Cochin natural gas liquids pipeline system. The earnings increases were largely revenue related—Cochin's operating revenues increased $2.2 million (23%) and $11.9 million (60%), respectively—driven by system-wide increases in throughput volumes of 4% and 45%, respectively. The increases in volumes were due to an increase in weather driven demand on the pipeline's West leg (U.S.), higher customer demand on the pipeline's East leg (Canadian), and for the comparable six month periods, to the exercise of a certain shipper incentive tariff offered in the first quarter of 2011;

- increases of $1.9 million (10%) and $3.9 million (10%), respectively, from our West Coast terminal operations. The increases in terminal earnings were mainly due to the completion of various terminal expansion projects that increased liquids tank capacity since the end of the second quarter of 2010;

- increases of $0.8 million (7%) and $3.3 million (15%), respectively, from our 51%-owned Plantation pipeline system, reflecting higher net income earned by Plantation Pipe Line Company in the first half of 2011. Plantation's transportation margins (net of income tax expenses) were essentially flat across both second quarter periods, but for the comparable six month periods, Plantation benefitted from both higher oil loss allowance revenues (due to higher average products prices and an 8% increase in transport volumes) and the absence of an expense from the write-off of an uncollectible receivable in the first quarter of 2010;

- increases of $0.1 million (0%) and $4.4 million (3%), respectively, from our Pacific operations. For the comparable six month periods, the increase in earnings was driven by lower operating expenses, primarily attributable to both incremental product gains and lower environmental expenses;

- decreases of $4.7 million (22%) and $2.0 million (5%), respectively, from our Southeast terminal operations. The decreases in earnings were chiefly due to lower margins on inventory sales, due largely to an inventory adjustment in the second quarter of 2010, and for the comparable six month periods, partially offset by higher revenues and higher product inventory gains relative to the first half of 2010;

- decreases of $3.3 million (20%) and $4.4 million (15%), respectively, from our Central Florida Pipeline. The decreases were largely due to an 11% drop in pipeline delivery volumes in the second quarter of 2011, due primarily to weaker demand and to the incremental business of a competing terminal in Florida; and

- decreases of $1.4 million (10%) and $3.2 million (11%), respectively, from our Calnev Pipeline. The decreases in Calnev's earnings were largely revenue related—combined operating revenues dropped $2.0 million (10%) and $3.2 million (9%), respectively—due mainly to decreases of 27% and 21%, respectively, in ethanol handling volumes compared to the second quarter and first six months of 2010. The decreases in ethanol volumes were due both to lower deliveries to the Las Vegas market, and to incremental ethanol blending services offered by a competing terminal.

Natural Gas Pipelines

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(In millions, except operating statistics)			
Revenues(a)	$ 1,044.3	$ 1,029.7	$ 2,063.7	$ 2,266.4
Operating expenses(b)	(919.4)	(884.8)	(1,763.1)	(1,936.3)
Earnings from equity investments	56.7	40.1	103.8	73.9
Interest income and Other, net	1.3	0.1	2.4	2.3
Income tax expense	(1.6)	(0.1)	(2.9)	(0.7)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 181.3	$ 185.0	$ 403.9	$ 405.6
Natural gas transport volumes (Bcf)(c)	734.6	634.7	1,429.0	1,267.0
Natural gas sales volumes (Bcf)(d)	192.4	199.0	383.6	388.0

(a) Six month 2010 amount includes a $0.4 million increase in revenues from certain measurement period adjustments related to our October 1, 2009 natural gas treating business acquisition.

(b) Three and six month 2011 amounts include a $9.7 million increase in expense from the write-off of a receivable for fuel under-collected prior to 2011. Three and six month 2010 amounts include unrealized losses of $0.1 million and unrealized gains of $0.8 million, respectively, on derivative contracts used to hedge forecasted natural gas sales.

(c) Includes Kinder Morgan Interstate Gas Transmission LLC, Trailblazer Pipeline Company LLC, TransColorado Gas Transmission Company LLC, Rockies Express Pipeline LLC, Midcontinent Express Pipeline LLC, Kinder Morgan Louisiana Pipeline LLC and Texas intrastate natural gas pipeline group, and for 2011 only, Fayetteville Express Pipeline LLC pipeline volumes.

(d) Represents Texas intrastate natural gas pipeline group volumes.

For the three and six months ended June 30, 2011, the certain items related to our Natural Gas Pipelines business segment and described in the footnotes to the table above decreased earnings before depreciation, depletion and amortization by $9.6 million and $10.9 million, respectively, and also decreased revenues in the first six months of 2011 by $0.4 million, when compared to the same periods in 2010. Following is information for each of the comparable three and six month periods of 2011 and 2010, related to the segment's (i) remaining $5.9 million (3%) and $9.2 million (2%) increases in earnings before depreciation, depletion and amortization; and (ii) $14.6 million (1%) increase and remaining $202.3 million (9%) decrease in operating revenues:

Three months ended June 30, 2011 versus Three months ended June 30, 2010

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
KinderHawk Field Services(a)	$ 10.9	n/a	$ n/a	n/a
Fayetteville Express Pipeline(a)	4.8	n/a	n/a	n/a
Casper and Douglas Natural Gas Processing	4.4	107 %	11.9	49 %
Midcontinent Express Pipeline(a)	2.7	37 %	n/a	n/a
Kinder Morgan Interstate Gas Transmission	(5.1)	(20)%	(6.1)	(15)%
Rockies Express Pipeline(a)	(4.0)	(17)%	n/a	n/a
Trailblazer Pipeline	(4.0)	(38)%	(1.3)	(11)%
Texas Intrastate Natural Gas Pipeline Group	(3.4)	(5)%	11.3	1 %
All others (including eliminations)	(0.4)	(1)%	(1.2)	(3)%
Total Natural Gas Pipelines	$ 5.9	3 %	$ 14.6	1 %

Six months ended June 30, 2011 versus Six months ended June 30, 2010

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
KinderHawk Field Services(a)	$ 20.6	n/a	$ n/a	n/a
Midcontinent Express Pipeline(a)	7.5	58 %	n/a	n/a
Casper and Douglas Natural Gas Processing	7.2	79 %	13.5	25 %
Fayetteville Express Pipeline(a)	5.6	n/a	n/a	n/a
Kinder Morgan Interstate Gas Transmission	(15.7)	(28)%	(13.2)	(17)%
Rockies Express Pipeline(a)	(6.3)	(14)%	n/a	n/a
Trailblazer Pipeline	(6.0)	(26)%	(1.4)	(5)%
Texas Intrastate Natural Gas Pipeline Group	(0.8)	-	(199.4)	(10)%
All others (including eliminations)	(2.9)	(3)%	(1.8)	(2)%
Total Natural Gas Pipelines	$ 9.2	2 %	$ (202.3)	(9)%

(a) Equity investments. 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.

The primary increases and decreases in our Natural Gas Pipelines business segment's earnings before depreciation, depletion and amortization expenses in the comparable three and six month periods of 2011 and 2010 included the following:

- increases of $10.9 million and $20.6 million, respectively, from incremental equity earnings from our 50%-owned KinderHawk Field Services LLC. We acquired our 50% investment in KinderHawk on May 21, 2010 and we subsequently accounted for our investment under the equity method of accounting. On July 1, 2011, we acquired the remaining 50% ownership interest in KinderHawk and beginning in the third quarter of 2011, we will account for our investment under the full consolidation method. For more information about our July 2011 KinderHawk acquisition, see Note 2 "Acquisitions and Divestitures—Acquisitions Subsequent to June 30, 2011" to our consolidated financial statements included elsewhere in this report;

- increases of $4.8 million and $5.6 million, respectively, from incremental equity earnings from our 50%-owned Fayetteville Express Pipeline LLC, which owns and operates the 187-mile Fayetteville Express natural gas pipeline system. It began interim transportation service in October 2010, and began firm contract transportation service to customers on January 1, 2011;

- increases of $4.4 million (107%) and $7.2 million (79%), respectively, from our Casper Douglas gas processing operations, primarily attributable to both higher natural gas processing spreads and higher liquids products sales volumes. The increases in sales volumes reflect more volumes received from gathering customers due largely to increased drilling activity in the Douglas, Wyoming plant area;

- increases of $2.7 million (37%) and $7.5 million (58%), respectively, from incremental equity earnings from our 50%-owned Midcontinent Express Pipeline LLC, primarily associated with the June 2010 completion of an expansion project that increased the system's Zone 1 transportation capacity from 1.5 to 1.8 billion cubic feet per day, and Zone 2 capacity from 1.0 to 1.2 billion cubic feet per day. The incremental capacity is fully subscribed with ten-year binding shipper agreements;

- decreases of $5.1 million (20%) and $15.7 million (28%), respectively, from our Kinder Morgan Interstate Gas Transmission pipeline system, driven by lower pipeline net fuel recoveries and lower interruptible and firm transportation revenues. The decreases in earnings reflect both lower natural gas prices, relative to 2010, and decreases of 10% and 9%, respectively, in system-wide transportation volumes. The drops in volumes were due in part to market pricing dynamics, which at times were uneconomic for shippers to transport to off-system markets;

- decreases of $4.0 million (17%) and $6.3 million (14%), respectively, from our 50%-owned Rockies Express pipeline system, reflecting lower net income earned by Rockies Express Pipeline LLC. The decreases in earnings were mainly due to higher pipeline maintenance expenses, and higher property tax expenses, both due to a higher asset base in 2011. For the comparable six month periods, the decrease in earnings was also due to higher interest expense associated with the securing of permanent financing for the Rockies Express pipeline construction costs (Rockies Express Pipeline LLC issued $1.7 billion aggregate principal amount of fixed rate senior notes in a private offering in March 2010), and to higher expenses associated with the write-off of certain transportation fuel recovery receivables pursuant to a contractual agreement;

- decreases of $4.0 million (38%) and $6.0 million (26%), respectively, from our Trailblazer pipeline system, mainly attributable to a $3.4 million increase in expense in the second quarter of 2011 from the write-off of receivables for under-collected fuel (incremental to the $9.7 million increase in expense described in footnote (b) to the results of operations table above), and to lower base transportation rates as a result of rate case settlements made since the end of the second quarter of 2010; and

- decreases of $3.4 million (5%) and $0.8 million (0%), respectively, from our Texas intrastate natural gas pipeline group. For the comparable three month periods, the decrease in earnings was driven by higher combined operating expenses, primarily due to higher pipeline maintenance and integrity expenses. For the comparable six month periods, the intrastate group's earnings were essentially unchanged, as lower natural gas sales margins and higher pipeline integrity expenses in the first half of 2011 were largely offset by higher margins from both natural gas transportation and storage services and natural gas processing, and by higher equity earnings from our 40%-owned Endeavor Gathering LLC.

The overall changes in both segment revenues and segment operating expenses (which include natural gas costs of sales) in the comparable three and six month periods of 2011 and 2010 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 gas purchase costs. For the comparable second quarter periods of 2011 and 2010, our Texas intrastate natural gas pipeline group accounted for 88% and 88%, respectively, of the segment's revenues, and 94% and 95%, respectively, of the segment's operating expenses. For the comparable six month periods of both years, the intrastate group accounted for 88% and 89%, respectively, of total revenues, and 94% and 95%, respectively, of total segment operating expenses.

CO_2

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(In millions, except operating statistics)			
Revenues(a)	$ 350.0	$ 314.6	$ 690.8	$ 636.4
Operating expenses	(89.3)	(72.6)	(172.9)	(151.7)
Earnings from equity investments	5.8	6.5	11.6	13.0
Interest income and Other, net	1.0	1.9	1.1	1.9
Income tax (expense) benefit	(1.1)	(1.0)	(2.2)	3.0
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 266.4	$ 249.4	$ 528.4	$ 502.6
Southwest Colorado carbon dioxide production (gross) (Bcf/d)(b)	1.3	1.3	1.3	1.3
Southwest Colorado carbon dioxide production (net) (Bcf/d)(b)	0.5	0.5	0.5	0.5
SACROC oil production (gross)(MBbl/d)(c)	28.4	29.1	28.6	29.5
SACROC oil production (net)(MBbl/d)(d)	23.7	24.2	23.9	24.6
Yates oil production (gross)(MBbl/d)(c)	21.8	24.3	21.8	24.9
Yates oil production (net)(MBbl/d)(d)	9.7	10.8	9.7	11.1
Katz oil production (gross)(MBbl/d)(c)	0.3	0.3	0.2	0.3
Katz oil production (net)(MBbl/d)(d)	0.2	0.3	0.2	0.3
Natural gas liquids sales volumes (net)(MBbl/d)(d)	8.4	10.1	8.3	9.9
Realized weighted average oil price per Bbl(e)	$ 69.37	$ 59.58	$ 69.07	$ 60.05
Realized weighted average natural gas liquids price per Bbl(f)	$ 66.67	$ 48.67	$ 63.83	$ 51.78

(a) Three and six month 2011 amounts include unrealized losses of $1.8 million and unrealized gains of $1.9 million, respectively, and three and six month 2010 amounts include unrealized gains of $7.9 million and $13.3 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 and an approximately 50% working interest in the Yates 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 Sales and Transportation Activities.

For the three and six months ended June 30, 2011, the unrealized gains and losses on derivative contracts used to hedge forecasted crude oil sales and described in footnote (a) to the table above decreased both earnings before depreciation, depletion and amortization and revenues by $9.7 million and $11.4 million, respectively, when compared to the same periods of 2010. For each of the segment's two primary businesses, following is information related to the increases and decreases, in the comparable three and six month periods of 2011 and 2010, in the segment's remaining (i) $26.7 million (11%) and $37.2 million (8%) increases in earnings before depreciation, depletion and amortization; and (ii) $45.1 million (15%) and $65.8 million (11%) increases in operating revenues:

Three months ended June 30, 2011 versus Three months ended June 30, 2010

	EBDA increase/(decrease)		Revenues Increase/(decrease)	
	(In millions, except percentages)			
Oil and Gas Producing Activities	$ 14.7	8 %	$ 31.3	13 %
Sales and Transportation Activities	12.0	18 %	17.2	23 %
Intrasegment eliminations	-	-	(3.4)	(25)%
Total CO_2	$ 26.7	11 %	$ 45.1	15 %

Six months ended June 30, 2011 versus Six months ended June 30, 2010

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Oil and Gas Producing Activities	$ 20.0	6 %	$ 43.2	9 %
Sales and Transportation Activities	17.2	13 %	31.1	21 %
Intrasegment eliminations	-	-	(8.5)	(32)%
Total CO_2	$ 37.2	8 %	$ 65.8	11 %

The segment's overall period-to-period increases in earnings before depreciation, depletion and amortization expenses were driven by higher earnings from its oil and gas producing activities, which include the operations associated with its ownership interests in oil-producing fields and natural gas processing plants. Generally, earnings for its oil and gas producing activities are closely aligned with realized price levels for crude oil and natural gas liquids products, and when compared to the same two periods of 2010, the increases in earnings in the three and six month periods ended June 30, 2011 were mainly due to the following:

- increases of $20.6 million (11%) and $31.8 million (8%), respectively, in crude oil sales revenues—due to higher average realizations for U.S. crude oil. Our realized weighted average price per barrel of crude oil increased 16% in the second quarter of 2011 and 15% in the first six months of 2011, when compared to the same periods in 2010. The overall increases in crude oil sales revenues were partially offset, however, by decreases in oil sales volumes of 5% and 6%, respectively, due primarily to a general year-over-year decline in production at both the SACROC and Yates field units;

- increases of $6.2 million (14%) and $3.8 million (4%), respectively, in natural gas plant products sales revenues, due to increases of 37% and 23%, respectively, in our realized weighted average price per barrel of natural gas liquids. The increases in revenues from higher realizations were partially offset by decreases in liquids sales volumes of 17% and 16%, respectively. The decreases in volumes were mainly related to the contractual reduction in our net interest in liquids production from the SACROC field (described following);

- increases of $5.1 million (137%) and $8.6 million (119%), respectively, in net profits revenues from our 28% net profits interest in the Snyder, Texas natural gas processing plant. The increases in net profits interest revenues from the Snyder plant were driven by higher natural gas liquids prices in the first half of 2011, and by the favorable impact from the restructuring of certain liquids processing contracts that became effective at the beginning of 2011. The contractual changes increased liquids processing production allocated to the plant, and decreased liquids production allocated to the SACROC field unit; and

- decreases of $14.6 million (20%) and $21.2 million (14%), respectively, due to higher combined operating expenses, driven by both higher carbon dioxide supply expenses and higher tax expenses, other than income tax expenses. The increases in carbon dioxide supply expenses were primarily due to initiating carbon dioxide injections into the Katz field, and to higher carbon dioxide prices. The increases in tax expenses were driven by higher severance tax expenses, chiefly due to higher crude oil revenues and a higher effective tax rate in the first half of 2011.

The overall period-to-period increases in earnings from the segment's sales and transportation activities were mainly due to the following:

- increases of $10.5 million (20%) and $23.5 million (23%), respectively, in carbon dioxide sales revenues, primarily due to higher average sales prices. The segment's average price received for all carbon dioxide sales in the second quarter and first six months of 2011 increased 18% and 23%, respectively, due largely to the fact that a portion of its carbon dioxide sales contracts are indexed to oil prices which have increased relative to both the second quarter and the first six months of last year. Overall carbon dioxide sales volumes increased by 1% in both the second quarter and first six months of 2011, versus the same prior year periods;

- increases of $3.4 million (198%) and $3.9 million (108%), respectively, in other revenues, due mainly to incremental earnings from third-party reimbursement and construction agreements;

- increases of $3.3 million (16%) and $3.7 million (10%), respectively, in carbon dioxide and crude oil pipeline transportation revenues, due mainly to incremental transportation service on our Eastern Shelf carbon dioxide pipeline which was completed in December 2010;

- decreases of $5.4 million (40%) and $8.3 million (30%), respectively, due to higher combined operating expenses. The increases in expense included higher carbon dioxide supply expenses, higher labor expenses that resulted from decreases in the amount of labor capitalized to construction projects, and higher severance tax expenses that related to higher commodity prices in the first half of 2011; and

- for the comparable six month periods, a $5.2 million (174%) decrease due to higher income tax expenses, resulting primarily from decreases in expense in the first half of 2010 due to favorable Texas margin tax liability adjustments related to the expensing of previously capitalized carbon dioxide costs.

Terminals

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	**2010**	**2011**	**2010**
	(In millions, except operating statistics)			
Revenues	$ 320.5	$ 320.5	$ 652.2	$ 624.6
Operating expenses(a)	(156.9)	(160.7)	(324.1)	(316.6)
Other income(b)	3.3	9.2	3.4	10.5
Earnings from equity investments	2.8	0.4	4.9	0.6
Interest income and Other, net(c)	3.8	(0.5)	4.5	0.4
Income tax (expense) benefit(d)	(3.2)	(3.4)	3.8	(3.5)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 170.3	$ 165.5	$ 344.7	$ 316.0
Bulk transload tonnage (MMtons)(d)	25.2	24.9	48.9	47.3
Ethanol (MMBbl)	13.7	14.6	29.3	30.1
Liquids leaseable capacity (MMBbl)	58.8	58.2	58.8	58.2
Liquids utilization %	92.6 %	95.8 %	92.6 %	95.8 %

(a) Three and six month 2011 amounts include (i) a $1.2 million increase in expense associated with environmental liability adjustments; (ii) increases in expense of $0.6 million and $1.6 million, respectively, associated with the repair of assets related to casualty losses; and (iii) a $0.1 million decrease in expense and a $0.6 million increase in expense, respectively, associated with the sale of our ownership interest in the boat fleeting business we acquired from Megafleet Towing Co., Inc. in April 2009. Six month 2011 amount also includes a $0.6 million increase in expense associated with the settlement of a litigation matter at our Carteret, New Jersey liquids terminal. Three and six month 2010 amounts include increases in expense of $0.2 million and $0.6 million, respectively, related to storm and flood clean-up and repair activities.

(b) Three and six month 2011 amounts include (i) a $4.3 million casualty indemnification gain related to a 2008 fire at our Pasadena, Texas liquids terminal; (ii) decreases in income of $0.6 million and $1.6 million, respectively, from the write-off of assets related to casualty losses; and (iii) a $0.1 million decrease in income and a $0.9 million increase in income, respectively, from adjustments associated with the sale of our ownership interest in the boat fleeting business we acquired from Megafleet Towing Co., Inc. in April 2009. Three and six month 2010 amounts include a $6.7 million casualty indemnification gain related to a 2008 fire at our Pasadena, Texas liquids terminal.

(c) Three and six month 2011 amounts include a combined $3.6 million gain from the sale of a 51% ownership interest in two of our subsidiaries: River Consulting LLC and Devco USA L.L.C.

(d) Three and six month 2011 amounts include (i) a $1.4 million increase in expense related to the gain associated with the sale of a 51% ownership interest in two of our subsidiaries described in footnote (c); and (ii) decreases in expense (reflecting tax savings) of $0.2 million and $4.7 million, respectively, related to non-cash compensation expense allocated to us from KMI (we do not have any obligation, nor do we expect to pay any amounts or realize any direct benefits related to this expense). Six month 2011 amount also includes a $1.9 million decrease in expense (reflecting tax savings) related to the net decrease in income from the sale of our ownership interest in the boat fleeting business described in both footnotes (a) and (b) and in Note 3 to our consolidated financial statements in our 2010 Form 10-K/A.

(d) Volumes for acquired terminals are included for all periods.

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. For the three and six months ended June 30, 2011, the certain items related to our Terminals business segment and described in the footnotes to the table above decreased segment earnings before depreciation, depletion and amortization expenses by $2.2 million and increased earnings before depreciation, depletion and amortization by $2.3 million, respectively, when compared to the same two periods of 2010.

In addition, in both 2011 and 2010, we acquired certain terminal assets and businesses in order to gain access to new markets or to complement and/or enlarge our existing terminal operations, and combined, these acquired operations contributed incremental earnings before depreciation, depletion and amortization of $3.6 million and revenues of $2.2 million in the second quarter of 2011. For the first six months of 2011, acquired assets contributed incremental earnings before depreciation, depletion and amortization of $7.6 million and revenues of $6.7 million.

All of the incremental amounts listed above represent the earnings, revenues and expenses from acquired terminals' operations during the additional months of ownership in 2011, and do not include increases or decreases during the same months we owned the assets in 2010. For more information about the terminal assets and operations we acquired in the first half of 2011, see Note 2 "Acquisitions and Divestitures—Acquisitions" to our consolidated financial statements included elsewhere in this report. For more information about our 2010 Terminal acquisitions, see Note 3 "Acquisitions and Divestitures—Acquisitions from Unrelated Entities" to our consolidated financial statements included in our 2010 Form 10-K/A.

Following is information, for the comparable three and six month periods of 2011 and 2010, related to the remaining increases and decreases in the segment's (i) earnings before depreciation, depletion and amortization expenses; and (ii) operating revenues. The changes represent increases and decreases in terminal results at various locations for all terminal operations owned during identical periods in both 2011 and 2010. We group our bulk and liquids terminal operations into regions based on geographic location and/or primary operating function. This structure allows our management to organize and evaluate segment performance and to help make operating decisions and allocate resources.

Three months ended June 30, 2011 versus Three months ended June 30, 2010

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Mid-Atlantic	$ 6.3	63 %	$ 5.3	21 %
Gulf Liquids	4.0	11 %	7.2	15 %
Southeast	0.8	6 %	0.4	2 %
Gulf Bulk	(5.7)	(32)%	(3.7)	(10)%
All others (including intrasegment eliminations and unallocated income tax expenses)	(2.0)	(2)%	(11.4)	(6)%
Total Terminals	$ 3.4	2 %	$ (2.2)	(1)%

Six months ended June 30, 2011 versus Six months ended June 30, 2010

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Gulf Liquids	$ 13.0	18 %	$ 17.2	18 %
Mid-Atlantic	8.4	40 %	10.1	20 %
Southeast	3.7	15 %	2.4	5 %
Gulf Bulk	(4.9)	(15)%	0.1	-
All others (including intrasegment eliminations and unallocated income tax expenses)	(1.4)	(1)%	(8.9)	(2)%
Total Terminals	$ 18.8	6 %	$ 20.9	3 %

The overall increases in earnings from the terminals included in our Mid-Atlantic region were driven by increases in earnings of $6.3 million and $9.7 million, respectively, from our Pier IX terminal, located in Newport News, Virginia. Its earnings increases were mainly due to increases of 57% and 66%, respectively, in coal transload volumes, consistent with the ongoing domestic economic recovery and with growth in the export market due to greater foreign demand for both U.S. metallurgical and steam coal.

The earnings increases from our Gulf Liquids terminals were driven by higher liquids revenues, mainly due to new and renewed customer agreements at higher rates, and to incremental revenues from the completion of terminal expansion projects in the fourth quarter of 2010 that increased liquids tank capacity at our Pasadena, Texas liquids terminal. Including all terminals, we increased our liquids terminals' leasable capacity by 0.6 million barrels (1%) since the end of the second quarter last year, via both terminal acquisitions and completed terminal expansion projects.

The increases in earnings before depreciation, depletion and amortization from our Southeast region terminals were driven by incremental contributions from both our Shipyard River Terminal, located in Charleston, South Carolina, and our liquids terminal facility located in Wilmington, North Carolina. The increases in earnings from our Shipyard facility were driven by higher chemicals and cement revenues, increased salt handling, and higher storage fees. The increases in earnings from our Wilmington terminal were due to both higher volumes and margins from tank blending services involving various agricultural products, and to a favorable environmental settlement in the second quarter of 2011.

The decreases in earnings from our Gulf Bulk terminals were primarily due to a $4.4 million decrease in earnings from our petroleum coke operations in the second quarter of 2011. The decrease in earnings, relative to the second quarter a year ago, was driven by a 27% drop in petroleum coke volumes, due mainly to production declines caused by refinery turnarounds and partly to certain contract terminations.

The remaining decreases in our Terminals segment's earnings and revenues—reported in the "All others" line in the two tables above—represent increases and decreases in terminal results at various locations; however the decreases in revenues relate largely to terminal assets we sold (or contributed to joint ventures) and no longer consolidate since the end of the second quarter of 2010.

Kinder Morgan Canada

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(In millions, except operating statistics)			
Revenues	$ 77.3	$ 70.6	$ 152.9	$ 130.4
Operating expenses	(24.0)	(23.7)	(50.4)	(43.2)
Losses from equity investments	(0.8)	(0.6)	(1.8)	(0.2)
Interest income and Other, net	3.3	1.8	6.7	7.6
Income tax expense(a)	(2.2)	(4.2)	(5.9)	(5.7)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 53.6	$ 43.9	$ 101.5	$ 88.9
Transport volumes (MMBbl)(b)	22.9	28.3	49.6	52.1

(a) Three and six month 2011 amounts include a $2.2 million decrease in expense (reflecting tax savings) related to non-cash compensation expense allocated to us from KMI (we do not have any obligation, nor do we expect to pay any amounts or realize any direct benefits related to this expense).
(b) 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 our one-third ownership interest in the Express crude oil pipeline system. For the comparable three and six month periods, the certain item relating to income tax savings described in footnote (a) to the table above increased earnings before depreciation, depletion and amortization $2.2 million in both the second quarter and first six months of 2011, when compared to the same two periods last year. For each of the segment's three primary businesses, following is information for each of the comparable three and six month periods of 2011 and 2010, related to the segment's (i) remaining $7.5 million (17%) and $10.4 million (12%) increases in earnings before depreciation, depletion and amortization; and (ii) $6.7 million (9%) and $22.5 million (17%) increases in operating revenues:

Three months ended June 30, 2011 versus Three months ended June 30, 2010

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Trans Mountain Pipeline	$ 6.7	16 %	$ 6.6	10 %
Jet Fuel Pipeline	0.7	209 %	0.1	6 %
Express Pipeline(a)	0.1	2 %	n/a	n/a
Total Kinder Morgan Canada	$ 7.5	17 %	$ 6.7	9 %

Six months ended June 30, 2011 versus Six months ended June 30, 2010

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Trans Mountain Pipeline	$ 11.2	14 %	$ 22.3	18 %
Jet Fuel Pipeline	0.4	22 %	0.2	6 %
Express Pipeline(a)	(1.2)	(18)%	n/a	n/a
Total Kinder Morgan Canada	$ 10.4	12 %	$ 22.5	17 %

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

The overall period-to-period increases in segment earnings before depreciation, depletion and amortization expenses were driven by higher revenues earned by our Trans Mountain pipeline system, primarily due to favorable impacts from a negotiated pipeline toll settlement agreement which became effective on January 1, 2011, increased crude oil deliveries into Washington State, and favorable impacts from foreign currency translation (due to the strengthening of the Canadian dollar since the end of the second quarter of 2010). The one-year negotiated toll agreement was formally approved by the National Energy Board (Canada) on April 29, 2011, and replaces the previous mainline toll settlement agreement that expired on December 31, 2010.

Other

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(In millions)			
General and administrative expenses(a)	$ 97.4	$ 93.4	$ 286.6	$ 194.5
Interest expense, net of unallocable interest income(b)	$ 129.6	$ 123.8	$ 261.3	$ 240.1
Unallocable income tax expense	$ 2.4	$ 2.0	$ 4.7	$ 4.2
Net income attributable to noncontrolling interests(c)	$ 1.4	$ 3.9	$ 4.5	$ 6.0

(a) Includes such items as salaries and employee-related expenses, payroll taxes, insurance, office supplies and rentals, unallocated litigation and environmental expenses, and shared corporate services. Three and six month 2011 amounts include (i) a $1.4 million increase in unallocated payroll tax expense (related to the $87.1 million special non-cash bonus expense to non-senior management employees allocated to us from KMI in the first quarter of 2011; however, we do not have any obligation, nor do we expect to pay any amounts related to this expense); (ii) increases in expense of $0.6 million and $1.1 million, respectively, for certain asset and business acquisition costs; and (iii) a $0.1 million decrease in expense related to capitalized overhead costs associated with the 2008 hurricane season. Six month 2011 amount also includes a combined $89.9 million increase in non-cash compensation expense (including $87.1 million related to a special non-cash bonus expense to non-senior management employees), allocated to us from KMI; however, we do not have any obligation, nor do we expect to pay any amounts related to this expense. Three and six month 2010 amounts include (i) increases in expense of $1.3 million and $2.7 million, respectively, from non-cash compensation expense allocated to us from KMI (we do not have any obligation, nor do we expect to pay any amounts related to these expenses); (ii) increases in expense of $1.0 million and $2.4 million, respectively, for certain asset and business acquisition costs; and (iii) an increase in expense of $0.1 million and a decrease in expense of $0.2 million, respectively, related to capitalized overhead costs associated with the 2008 hurricane season. Six month 2010 amount also includes an increase in legal expense of $1.6 million associated with certain items such as legal settlements and pipeline failures.

(b) Three and six month 2011 amounts include increases in imputed interest expense of $0.2 million and $0.4 million, respectively, and three and six month 2010 amounts include increases in imputed interest expense of $0.2 million and $0.6 million, respectively, all related to our January 1, 2007 Cochin Pipeline acquisition.

(c) Three and six month 2011 amounts include decreases of $2.4 million and $3.5 million, respectively, in net income attributable to our noncontrolling interests, and the three and six month 2010 amounts include decreases of $0.1 million and $2.4 million, respectively, in net income attributable to our noncontrolling interests, all related to the combined effect of the three and six month 2011 and 2010 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 salaries and employee-related expenses, 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.

Combined, the certain items described in footnote (a) to the table above decreased our general and administrative expenses by $0.5 million in the second quarter of 2011 and increased our general and administrative expenses by $85.8 million in the first half of 2011, when compared to the same two periods of 2010. The remaining $4.5 million (5%) and $6.3 million (3%) period-to-period increases in expenses were driven by (i) higher employee benefit and payroll tax expenses, due mainly to cost inflation increases on work-based health and insurance benefits and to higher wage rates; (ii) higher labor expenses, primarily due to a larger year-over-year labor force; and (iii) higher unallocated environmental expenses, related to our Canadian pipeline operations. The overall increases in expense were partially offset by lower unallocated legal and insurance expenses.

In the table above, 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 items described in footnote (b) to the table above, our interest expense increased by $5.8 million (5%) in the second quarter of 2011, and by $21.4 million (9%) in the first six months of 2011, when compared with the same prior year periods. The increases in interest expense were primarily due to higher average debt balances in the first half of 2011. Average borrowings for the three and six month periods ended June 30, 2011 increased 1.3% and 2.2%, respectively, when compared to the same periods a year ago, largely due to the capital expenditures, business acquisitions, and joint venture contributions we have made since the end of the second quarter of 2010. The weighted average interest rates on all of our borrowings (including both short-term and long-term amounts) in 2011 were essentially flat versus the average rates during 2010—from 4.33% for the second quarter of 2010 to 4.29% for the second quarter of 2011, and from 4.33% for the first six months of 2010 to 4.36% for the first six months of 2011.

We use interest rate swap agreements to transform a portion of the underlying cash flows related to 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, and in periods of rising interest rates, these swaps result in period-to-period increases in our interest expense. As of June 30, 2011, approximately 47% of our $11,406.9 million consolidated debt balance (excluding the value of interest rate swap agreements) 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 swaps. For more information on our interest rate swaps, see Note 6 "Risk Management—Interest Rate Risk Management" to our consolidated financial statements included elsewhere in this report.

Financial Condition

General

As of June 30, 2011, we believe our balance sheet and liquidity position remained strong. Cash and cash equivalents on hand at quarter end was $352.6 million, an increase of $223.5 million from December 31, 2010. We also had, as of June 30, 2011, approximately $1.8 billion of borrowing capacity available under our $2.0 billion senior unsecured revolving bank credit facility (discussed below in "—Short-term Liquidity"). We believe our cash position and our remaining borrowing capacity allow us to manage our day-to-day cash requirements and any anticipated obligations, and currently, we believe our liquidity to be adequate.

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 with additional borrowings, as such debt principal payments become due, 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

As part of our financial strategy, we try to maintain an investment-grade credit rating, which involves, among other things, the issuance of additional limited partner units in connection with our acquisitions and expansion activities in order to maintain acceptable financial ratios. The major debt rating agencies routinely evaluate our outstanding debt, and our cost of borrowing can increase or decrease depending on these debt ratings. 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.

On February 22, 2011, Moody's revised its outlook on our long-term credit rating to stable from negative, affirmed our long-term credit rating at Baa2, and upgraded our short-term credit rating to Prime-2 from Prime-3. The rating agency's revisions reflected its expectations that our outstanding debt balance and overall capital structure should improve over the next year due largely to higher expected cash flows associated with both completed construction on the Rockies Express, Midcontinent Express, Fayetteville Express and Kinder Morgan Louisiana natural gas pipeline systems, and the businesses and investments we acquired during 2010. For additional information about our 2010 capital expenditures, acquisition expenditures, and investment contributions, see "Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources" in our 2010 Form 10-K.

As a result of this upward revision to our short-term credit rating, we currently have broader access to the commercial paper market that was not available prior to this rating change, and therefore, 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 and terminals industries and other financial and business factors, some of which are beyond our control.

Additionally, some of our customers are experiencing, or may experience in the future, severe financial problems that have had or may have a significant impact on their creditworthiness. These financial problems may arise from current global economic conditions, changes in commodity prices or otherwise. We have been and are working to implement, to the extent allowable under applicable contracts, tariffs and regulations, prepayments and other security requirements, such as letters of credit, to enhance our credit position relating to amounts owed from these customers. We cannot provide assurance that one or more of our current or future financially distressed customers will not default on their obligations to us or that such a default or defaults will not have a material adverse effect on our business, financial position, future results of operations, or future cash flows; however, we believe we have provided adequate allowance for such customers.

Short-term Liquidity

As of June 30, 2011, our principal sources of short-term liquidity were (i) our $2.0 billion senior unsecured revolving credit facility that had a maturity date of June 23, 2013; (ii) our $2.0 billion short-term commercial paper program (which is supported by our revolving 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. 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. On July 1, 2011, we amended our credit facility to, among other things, increase the available borrowings up to $2.2 billion and extend the maturity date to July 1, 2016. The amended credit facility can be amended to allow for borrowings of up to $2.5 billion.

As discussed above in "—General," we provide for additional liquidity by maintaining a sizable amount of excess borrowing capacity related to our bank credit facility. After reduction for our outstanding letters of credit, the remaining available borrowing capacity under our credit facility was $1,768.5 million as of June 30, 2011.

Additionally, we have consistently generated strong cash flow from operations. In the first six months of 2011 and 2010, we generated $1,252.0 million and $932.2 million, respectively, of cash from operating activities (the period-to-period increase is discussed below in "—Operating Activities").

Our outstanding short-term debt as of June 30, 2011 was $991.3 million, primarily consisting of (i) $500.0 million in principal amount of 9.00% senior notes that mature February 1, 2019, but that we may be required to repurchase at the option of the holders on February 1, 2012 pursuant to certain repurchase provisions contained in the bond indenture; and (ii) $450.0 million in principal amount of 7.125% senior notes that mature March 15, 2012. 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 additional bank credit facility borrowings to replace maturing commercial paper and current maturities of long-term debt.

We had working capital deficits (current assets minus current liabilities) of $991.9 million as of June 30, 2011 and $1,477.5 million as of December 31, 2010. The favorable change from year-end 2010 was primarily due to (i) a $223.5 million increase in cash and cash equivalents, due mainly to proceeds received from our May 2011 public offering of an additional 7,705,000 common units; and (ii) a $271.1 million drop in short-term debt, primarily due to our refinancing, in March 2011, of maturing $700 million outstanding aggregate principal amount of senior notes with the public offering of $1.1 billion in principal amount of long-term senior notes.

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"). As a result, our working capital balance could return to a surplus in future periods. A working capital deficit is not unusual for us or for other companies similar in size and scope to us, and we believe that our working capital deficit does not indicate a lack of liquidity as we continue to maintain adequate current assets and committed lines of credit to satisfy current liabilities and maturing obligations when they come due.

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 notes 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 on our 2011 equity issuances, see Note 5 "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. For more information on our debt related transactions in the first half of 2011, including our issuances of senior notes, see Note 4 "Debt" to our consolidated financial statements included elsewhere in this report.

As of June 30, 2011 and December 31, 2010, the net carrying value of the various series of our senior notes was $11,276.9 million and $10,876.7 million, respectively, and the total liability balance due on the various borrowings of our operating partnerships and subsidiaries was $130.0 million and $141.0 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. Based on our historical record, we believe that our capital structure will continue to allow us to achieve our business objectives. For additional information regarding our debt securities, see Note 8 "Debt" to our consolidated financial statements included in our 2010 Form 10-K/A.

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 Structure

We attempt to maintain a relatively conservative overall capital structure, financing our expansion capital expenditures and acquisitions with approximately 50% equity and 50% debt. In the short-term, we fund these expenditures from borrowings under our credit facility until the amount borrowed is of a sufficient size to cost effectively offer either debt, or equity, or both.

With respect to our debt, we target a debt mixture of approximately 50% fixed and 50% variable interest rates. We achieve our variable rate exposure primarily by issuing long-term fixed rate debt and then swapping the fixed rate interest payments for variable rate payments.

Capital Expenditures

We define sustaining capital expenditures as capital expenditures which do not increase the capacity of an asset, and for the first six months of 2011, our sustaining capital expenditures were $85.2 million. This amount included $2.5 million for our proportionate share of the sustaining capital expenditures of (i) Rockies Express Pipeline LLC; (ii) Midcontinent Express Pipeline LLC; (iii) KinderHawk Field Services LLC (effective July 1, 2011, we acquired the remaining 50% ownership interest in KinderHawk that we did not already own and beginning in the third quarter of 2011, we will account for our investment under the full consolidation method); (iv) Cypress Interstate Pipeline LLC; and (v) Fayetteville Express Pipeline LLC. For the first half of 2010, our sustaining capital expenditures totaled $80.4 million (including $0.1 million for our proportionate share of the sustaining capital expenditures of the five equity investees listed above). Our forecasted expenditures for the remaining six months of 2011 for sustaining capital expenditures are $138.5 million, including $5.0 million for our proportionate shares of Rockies Express, Midcontinent Express, Fayetteville Express and Cypress.

Generally, we fund our sustaining capital expenditures with existing cash or from cash flows from operations. In addition to utilizing cash generated from their own operations, Rockies Express, Midcontinent Express and Fayetteville Express can each fund their own cash requirements for expansion capital expenditures through borrowings under their own credit facilities or with proceeds from contributions received from their member owners. Both Rockies Express and Midcontinent Express can also generate funds by issuing their own long-term notes.

We have no contingent debt obligations with respect to Rockies Express, Midcontinent Express, or Cypress; however, we guarantee 50% of Fayetteville Express Pipeline LLC's bank credit facility borrowings. For information on our contingent debt obligations, see Note 4 "Debt—Contingent Debt" to our consolidated financial statements included elsewhere in this report.

All of our capital expenditures, with the exception of sustaining capital expenditures, are classified as discretionary. Our discretionary capital expenditures for each of the six month periods ended June 30, 2011 and 2010 were $452.7 million and $370.8 million, respectively. The increase in discretionary expenditures from the first six months of 2010 was primarily due to higher investment undertaken in the first half of 2011 to expand and improve our CO_2 and Terminals business segments. Generally, we initially fund our discretionary capital expenditures through borrowings under our bank credit facility or our commercial paper program until the amount borrowed is of a sufficient size to cost effectively offer either debt, or equity, or both. As of June 30, 2011, our current forecast for discretionary capital expenditures for 2011 is approximately $1.1 billion. This amount does not include forecasted discretionary expenditures by our equity investees, forecasted capital contributions to our equity investees, or forecasted expenditures for asset acquisitions.

Operating Activities

Net cash provided by operating activities was $1,252.0 million for the six months ended June 30, 2011, versus $932.2 million in the same comparable period of 2010. The period-to-period increase of $319.8 million (34%) in cash flow from operations consisted of the following:

- a $143.3 million increase in cash attributable to higher payments made in 2010 to various shippers on our Pacific operations' refined products pipelines. In June 2010 and March 2011, we paid legal settlements of $206.3 million and $63.0 million, respectively, to settle various transportation rate challenges filed by the shippers with the FERC dating back as early as 1992;

- a $59.5 million increase in cash relative to net changes in working capital items, primarily due to (i) a $55.3 million increase in cash from the collection and payment of trade and related party receivables and payables (including collections and payments on natural gas transportation and exchange imbalance receivables and payables), due primarily to the timing of invoices received from customers and paid to vendors and suppliers; (ii) a $41.8 million increase in cash from net changes in inventories, primarily due to lower spending for both materials and supplies and short-term crude oil and refined products inventories; (iii) a $21.1 million increase in cash from net changes in accrued tax liabilities, driven by lower net settlements of property tax liabilities in the first half of 2011; and (iv) a $55.5 million decrease in cash from higher payments for natural gas storage on our Kinder Morgan Texas Pipeline system;

- a $47.2 million increase in cash related to net changes in both non-current assets and liabilities and other non-cash income and expense items, primarily driven by (i) a $60.2 million increase in cash due to higher net dock premiums and toll collections received from our Trans Mountain pipeline system customers; and (ii) a net $14.4 million decrease in cash attributable to lower non-cash earning adjustments in the first half of 2011, including among other items, income from the sale or casualty of net assets, amortization of debt-related discounts and premiums, and deferred tax expenses;

- a $36.0 million increase in cash from overall higher partnership income—after adjusting our period-to-period $19.7 million decrease in net income for the following four non-cash items: (i) an $87.2 million increase due to certain higher non-cash compensation expenses allocated to us from KMI (as discussed in Note 9 "Related Party Transactions" to our consolidated financial statements included elsewhere in this report, we not have any obligation, nor do we expect to pay any amounts related to these allocated expenses); (ii) a $7.0 million increase in expense from adjustments made to our rate case liabilities (in June 2011 and March 2010 we increased our combined rate case reserve by $165.0 million and $158.0 million, respectively); (iii) a $0.9 million increase due to higher non-cash depreciation, depletion and amortization expenses (including amortization of excess cost of equity investments); and (iv) a $39.4 million decrease due to higher earnings from equity investees. The period-to-period change in partnership income in 2011 versus 2010 is discussed above in "—Results of Operations" (including all of the certain items disclosed in the associated table footnotes); and

- a $33.8 million increase in cash from higher distributions of earnings from equity investees. The increase was chiefly due to incremental distributions of $20.4 million received from our 50%-owned KinderHawk Field Services LLC (acquired in May 2010), and $7.5 million received from our 50%-owned Midcontinent Express Pipeline LLC.

Investing Activities

Net cash used in investing activities was $518.7 million for the six month period ended June 30, 2011, compared to $1,667.9 million in the comparable 2010 period. The $1,149.2 million (69%) increase in cash in the first half of 2011 due to lower cash expended for investing activities was primarily attributable to:

- a $1,037.8 million increase in cash due to lower acquisitions of assets and investments relative to the first half of 2010. In the first six months of 2011, we paid $110.0 million for strategic acquisitions, including (i) $50.0 million paid in January 2011 for our preferred equity interest in Watco Companies, LLC; and (ii) $42.9 million paid in June 2011 for terminal assets acquired from TGS Development, L.P. (both acquisitions are discussed further in Note 2 to our consolidated financial statements included elsewhere in this report). In the first six months of 2010, our cash outlays for strategic business acquisitions totaled $1,147.8 million, primarily consisting of the following: (i) $921.4 million for a 50% ownership interest in KinderHawk Field Services LLC in May 2010; (ii) $115.7 million for three unit train ethanol handling terminals acquired from US Development Group LLC in January 2010; and (iii) $97.0 million for terminal assets and investments acquired from Slay Industries in March 2010;

- a $120.8 million increase in cash due to lower contributions to equity investees in the first half of 2011. During the first six months of 2011, we contributed $60.1 million to our equity investees, including payments of $41.9 million to our 50%-owned Eagle Ford Gathering LLC. Eagle Ford Gathering used the contributions as partial funding for natural gas gathering infrastructure expansions. In the first half of 2010, we contributed an aggregate amount of $180.9 million, including $130.5 million to Rockies Express Pipeline LLC and $39.0 million to Midcontinent Express Pipeline LLC to partially fund our respective share of Rockies Express and Midcontinent Express natural gas pipeline system construction costs;

- a $50.0 million increase in cash due to release of restricted cash. As of December 31, 2010, we placed the $50.0 million cash we paid in January 2011 for our equity investment in Watco Companies, LLC in a cash escrow account, and we reported this amount as "Restricted Deposits" on our year-end balance sheet;

- a $27.9 million increase in cash due to higher capital distributions (distributions in excess of cumulative earnings) received from equity investments in the first half of 2011—chiefly due to incremental capital distributions received from KinderHawk Field Services LLC and the Red Cedar Gathering Company; and

- an $84.3 million decrease in cash due to higher capital expenditures, as described above in "—Capital Expenditures."

Financing Activities

Net cash used in financing activities amounted to $512.8 million for the first six months of 2011, and for the same comparable period last year, we provided net cash of $733.0 million from our financing activities. The $1,245.8 million (170%) overall decrease in cash was mainly due to:

- a $1,378.3 million decrease in cash from overall debt financing activities—which include our issuances and payments of debt and our debt issuance costs. The decrease in cash was primarily due to (i) a $798.5 million decrease due to lower net short-term borrowings (consisting of borrowings under both our commercial paper program and our bank credit facility); and (ii) a $600.4 million decrease due to lower net issuances and repayments of our senior notes (in the first six months of 2011, we generated net proceeds of $392.7 million from issuing and repaying senior notes, and in May 2010, we received net proceeds of $993.1 million from the public offering of $1.0 billion aggregate principal amount of senior notes).

  Due in part to our short-term credit rating upgrade in February 2011, we made no short-term borrowings under our bank credit facility in the first half of 2011, but instead made borrowings under our commercial paper program. For more information about our debt financing activities, see Note 4 to our consolidated financial statements included elsewhere in this report;

- a $124.8 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 $1,085.8 million in the first half of 2011. In the first six months of 2010, we distributed $961.0 million to our partners. Further information regarding our distributions is discussed following in "—Partnership Distributions;" and

- a $272.6 million increase in cash due to higher partnership equity issuances. The increase reflects the $705.8 million we received, after commissions and underwriting expenses, from the sales of additional common units in the first six months of 2011 (discussed in Note 5 "Partners' Capital—Equity Issuances" to our consolidated financial statements included elsewhere in this report), versus the $433.2 million we received from the sales of additional common units in the same six month period a year ago. We used the proceeds from our 2011 equity issuances to reduce the borrowings under our commercial paper program, and in 2010, to reduce the borrowings under both our commercial paper program and our bank credit facility.

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 2010 Form 10-K/A 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.

On May 13, 2011, we paid a quarterly distribution of $1.14 per unit for the first quarter of 2011. This distribution was 7% greater than the $1.07 distribution per unit we paid in May 2010 for the first quarter of 2010. We paid this distribution in cash to our general partner, our common unitholders, and our sole Class B unitholder. KMR, our sole i-unitholder, received additional i-units based on the $1.14 cash distribution per common unit.

The incentive distribution that we paid on May 13, 2011 to our general partner (for the first quarter of 2011) totaled $280.0 million, and the incentive distribution that we paid in May 2010 (for the first quarter of 2010) totaled $249.4 million. The increase in the incentive distribution paid to our general partner in the second quarter of 2011 versus the second quarter of 2010 reflects the increase in amounts distributed per unit as well as an increase in the number of common units and i-units outstanding; however, the first quarter 2011 incentive distribution was affected by a waived incentive distribution amount equal to $7.1 million related to common units issued to finance a portion of our May 2010 acquisition of an initial 50% ownership interest in KinderHawk Field Services LLC. Our general partner has agreed (i) to forego all incentive distributions related to this initial 50% joint venture acquisition through year-end 2011; and (ii) to forego incremental incentive distributions of approximately $26 million in 2012 and approximately $4 million in 2013 related to our subsequent acquisition of the remaining 50% ownership interest in KinderHawk Field Services LLC (effective July 1, 2011).

On July 20, 2011, we declared a cash distribution of $1.15 per unit for the second quarter of 2011 (an annualized rate of $4.60 per unit). This distribution is 6% higher than the $1.09 per unit distribution we made for the second quarter of 2010. For more information about our second quarter 2011 and second quarter 2010 cash distributions, see Note 5 "Partners' Capital—Subsequent Events" to our consolidated financial statements included elsewhere in this report.

In November 2010, we announced that we expected to declare cash distributions of $4.60 per unit for 2011, a 4.5% increase over our cash distributions of $4.40 per unit for 2010. 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 expected growth in distributions in 2011 assumes an average West Texas Intermediate (WTI) crude oil price of approximately $89 per barrel (with some minor adjustments for timing, quality and location differences) in 2011, 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 2011 budget), we currently expect the average price of WTI crude oil will be approximately $98 per barrel in 2011. Furthermore, for 2011, 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 $5.0 million (or less than 0.2% 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 2010.

Off Balance Sheet Arrangements

Except as set forth with respect to contingent debt agreements with Midcontinent Express Pipeline LLC and Fayetteville Express Pipeline LLC under "—Contingent Debt" in Note 4 "Debt" to our consolidated financial statements included elsewhere in this report, 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, 2010 in our 2010 Form 10-K.

Recent Accounting Pronouncements

Please refer to Note 12 "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. Specific factors which could cause actual results to differ from those in the forward-looking statements include:

- price trends and overall demand for natural gas liquids, refined petroleum products, oil, carbon dioxide, natural gas, electricity, coal, steel and other bulk materials and chemicals in North America;

- economic activity, weather, alternative energy sources, conservation and technological advances that may affect price trends and demand;

- changes in our tariff rates implemented by the Federal Energy Regulatory Commission, California Public Utilities Commission, Canada's National Energy Board or another regulatory agency;
- our ability to acquire new businesses and assets and integrate those operations into our existing operations, as well as our ability to expand our facilities;
- difficulties or delays experienced by railroads, barges, trucks, ships or pipelines in delivering products to or from our terminals or pipelines;
- our ability to successfully identify and close acquisitions and make cost-saving changes in operations;
- shut-downs or cutbacks at major refineries, petrochemical or chemical plants, ports, utilities, military bases or other businesses that use our services or provide services or products to us;
- changes in crude oil and natural gas production from exploration and production areas that we serve, such as the Permian Basin area of West Texas, the U.S. Rocky Mountains, areas of shale gas formation and the Alberta oil sands;
- changes in laws or regulations, third-party relations and approvals, and decisions of courts, regulators and governmental bodies that may adversely affect our business or our ability to compete;
- changes in accounting standards that impact the measurement of our results of operations, the timing of when such measurements are to be made and recorded, and the disclosures surrounding these activities;
- our ability to offer and sell equity securities and debt securities or obtain debt financing in sufficient amounts to implement that portion of our business plan that contemplates growth through acquisitions of operating businesses and assets and expansions of our facilities;
- our indebtedness, which could make us vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds, and/or place us at competitive disadvantages compared to our competitors that have less debt or have other adverse consequences;
- interruptions of electric power supply to our facilities due to natural disasters, power shortages, strikes, riots, terrorism, war or other causes;
- our ability to obtain insurance coverage without significant levels of self-retention of risk;
- acts of nature, accidents, sabotage, terrorism or other similar acts causing damage greater than our insurance coverage limits;
- capital and credit markets conditions, inflation and interest rates;
- the political and economic stability of the oil producing nations of the world;
- national, international, regional and local economic, competitive and regulatory conditions and developments;
- our ability to achieve cost savings and revenue growth;
- foreign exchange fluctuations;
- the timing and extent of changes in commodity prices for oil, natural gas, electricity and certain agricultural products;
- the extent of our success in discovering, developing and producing oil and gas reserves, including the risks inherent in exploration and development drilling, well completion and other development activities;

- engineering and mechanical or technological difficulties that we may experience with operational equipment, in well completions and workovers, and in drilling new wells;
- the uncertainty inherent in estimating future oil and natural gas production or reserves that we may experience;
- the ability to complete expansion projects on time and on budget;
- the timing and success of our business development efforts; and
- unfavorable results of litigation and the fruition of contingencies referred to in Note 10 to our consolidated financial statements included elsewhere in this report.

The foregoing list should not be construed to be exhaustive. We believe the forward-looking statements in this report are reasonable. However, there is no assurance that any of the actions, events or results of the forward-looking statements will occur, or if any of them do, what impact they will have on our results of operations or financial condition. Because of these uncertainties, you should not put undue reliance on any forward-looking statements.

See Part I, Item 1A "Risk Factors" of our 2010 Form 10-K for a more detailed description of these and other factors that may affect the forward-looking statements. When considering forward-looking statements, one should keep in mind the risk factors described in our 2010 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 the above list or to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments.

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, 2010, in Item 7A of our 2010 Form 10-K. For more information on our risk management activities, see Note 6 "Risk Management" to our consolidated financial statements included elsewhere in this report.

Item 4. Controls and Procedures.

As of June 30, 2011, 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 June 30, 2011 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 10 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 2010 Form 10-K.

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

Effective June 10, 2011, we issued 324,961common units as part of the purchase price for certain petroleum coke terminal assets that we acquired from TGS Development, L.P. The total purchase price for the acquired assets was approximately $74.1 million, consisting of $42.9 million in cash, $23.7 million in common units, and an obligation to pay additional consideration of $7.5 million approximately one year from close. The units issued in June 2011 were issued to a single accredited investor in a transaction not involving a public offering and were therefore exempt from registration pursuant to Section 4(2) of the Securities Act of 1933.

Item 3. Defaults Upon Senior Securities.

None.

Item 4. (Removed and Reserved)

Item 5. Other Information.

On July 20, 2011, C. Berdon Lawrence resigned from the KMR and Kinder Morgan G.P., Inc. boards of directors. Mr. Lawrence resigned because of an investment he made in a small family business that transacts certain terminal-related business with us. On the same date, Mr. Ted A. Gardner was elected as a director of the KMR and Kinder Morgan G.P., Inc. boards to fill the vacancy left by Mr. Lawrence. Mr. Gardner also was appointed to serve on the audit committee, compensation committee, and nomination and governance committee of the KMR and Kinder Morgan G.P., Inc. boards. Since 2005, Mr. Gardner has been a managing partner of Silverhawk Capital Partners in Charlotte, North Carolina. Formerly, he was a director of Kinder Morgan, Inc. from 1999 to 2007, and was a director of Encore Acquisition Company from 2001 to 2010. Mr. Gardner is currently a director of Summit Materials Holdings and Spartan Energy Partners.

There are no arrangements between Mr. Gardner and any other persons pursuant to which Mr. Gardner was appointed as a director. Mr. Gardner has no family relationship with any of the directors or executive officers of KMR, Kinder Morgan G.P., Inc. or us. Mr. Gardner has no direct or indirect material interest in any transaction or proposed transaction required to be reported under Section 404(a) of Regulation S-K. Mr. Gardner will receive compensation for his service as a director consistent with the compensation policy for non-management directors of KMR and Kinder Morgan G.P., Inc. Non-management director annual compensation is $180,000, which the directors may elect to receive in either cash, our common units or a combination thereof.

Item 6. Exhibits.

4.1 — 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 C.F.R. sec.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 — First Amendment to Credit Agreement, dated as of July 1, 2011, among Kinder Morgan Energy Partners, L.P., Kinder Morgan Operating L.P. "B", the lenders party thereto and Wells Fargo Bank, National Association, as Administrative Agent.

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.

101 — Interactive data files pursuant to Rule 405 of Regulation S-T: (i) our Consolidated Statements of Income for the three and six months ended June 30, 2011 and 2010; (ii) our Consolidated Balance Sheets as of June 30, 2011 and December 31, 2010; (iii) our Consolidated Statements of Cash Flows for the six months ended June 30, 2011 and 2010; and (iv) the notes to our Consolidated Financial Statements.

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: July 29, 2011

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