

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

FORM 10-Q

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

For the quarterly period ended **March 31, 2010**

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

(State or other jurisdiction of
incorporation or organization)

76-0380342

(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 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 during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes 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 Securities Exchange Act of 1934. Large accelerated filer Accelerated filer Non-accelerated filer Smaller reporting company

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). Yes No

The Registrant had 207,310,563 common units outstanding as of April 30, 2010.

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

Item 1. Financial Statements.

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

	Three Months Ended	
	March 31,	
	2010	2009
Revenues		
Natural gas sales	\$ 1,017.5	\$ 888.7
Services	738.5	661.4
Product sales and other	373.6	236.4
Total Revenues	<u>2,129.6</u>	<u>1,786.5</u>
Operating Costs, Expenses and Other		
Gas purchases and other costs of sales	1,016.6	865.7
Operations and maintenance	452.9	250.0
Depreciation, depletion and amortization	227.3	210.2
General and administrative	101.1	82.5
Taxes, other than income taxes	45.1	39.0
Other expense (income)	(1.3)	(0.9)
Total Operating Costs, Expenses and Other	<u>1,841.7</u>	<u>1,446.5</u>
Operating Income	287.9	340.0
Other Income (Expense)		
Earnings from equity investments	46.7	38.2
Amortization of excess cost of equity investments	(1.4)	(1.4)
Interest, net	(111.5)	(97.2)
Other, net	6.7	10.7
Total Other Income (Expense)	<u>(59.5)</u>	<u>(49.7)</u>
Income Before Income Taxes	228.4	290.3
Income Taxes	<u>(1.0)</u>	<u>(23.5)</u>
Net Income	227.4	266.8
Net Income Attributable to Noncontrolling Interests	<u>(2.1)</u>	<u>(2.9)</u>
Net Income Attributable to Kinder Morgan Energy Partners, L.P.	<u>\$ 225.3</u>	<u>\$ 263.9</u>
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.	\$ 225.3	\$ 263.9
Less: General Partner's Interest	<u>(249.2)</u>	<u>(223.7)</u>
Limited Partners' Interest in Net Income (Loss)	<u>\$ (23.9)</u>	<u>\$ 40.2</u>
Limited Partners' Net Income (Loss) per Unit	<u>\$ (0.08)</u>	<u>\$ 0.15</u>
Weighted Average Number of Units Used in Computation of Limited Partners' Net Income per Unit	<u>298.8</u>	<u>269.4</u>
Per Unit Cash Distribution Declared	<u>\$ 1.07</u>	<u>\$ 1.05</u>

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

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

	March 31, 2010	December 31, 2009
	(Unaudited)	
ASSETS		
Current assets		
Cash and cash equivalents	\$ 134.4	\$ 146.6
Restricted deposits	-	15.2
Accounts, notes and interest receivable, net	819.1	902.1
Inventories	79.6	71.9
Gas in underground storage	51.9	43.5
Fair value of derivative contracts	58.6	20.8
Other current assets	26.9	44.6
Total current assets	<u>1,170.5</u>	<u>1,244.7</u>
Property, plant and equipment, net	14,348.3	14,153.8
Investments	2,928.9	2,845.2
Notes receivable	194.3	190.6
Goodwill	1,216.2	1,149.2
Other intangibles, net	329.0	218.7
Fair value of derivative contracts	297.3	279.8
Deferred charges and other assets	169.0	180.2
Total Assets	<u>\$ 20,653.5</u>	<u>\$ 20,262.2</u>
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Current portion of debt	\$ 1,734.4	\$ 594.7
Cash book overdrafts	45.6	34.8
Accounts payable	577.8	614.8
Accrued interest	94.6	222.4
Accrued taxes	64.1	57.8
Deferred revenues	86.9	76.0
Fair value of derivative contracts	278.2	272.0
Accrued other current liabilities	142.3	145.1
Total current liabilities	<u>3,023.9</u>	<u>2,017.6</u>
Long-term liabilities and deferred credits		
Long-term debt		
Outstanding	9,282.0	9,997.7
Value of interest rate swaps	393.6	332.5
Total Long-term debt	<u>9,675.6</u>	<u>10,330.2</u>
Deferred income taxes	227.9	216.8
Fair value of derivative contracts	365.3	460.1
Other long-term liabilities and deferred credits	669.5	513.4
Total long-term liabilities and deferred credits	<u>10,938.3</u>	<u>11,520.5</u>
Total Liabilities	<u>13,962.2</u>	<u>13,538.1</u>
Commitments and contingencies (Notes 4 and 10)		
Partners' Capital		
Common units	3,906.8	4,057.9
Class B units	72.6	78.6
i-units	2,675.0	2,681.7
General partner	224.7	221.1
Accumulated other comprehensive loss	(266.5)	(394.8)
Total Kinder Morgan Energy Partners, L.P. partners' capital	<u>6,612.6</u>	<u>6,644.5</u>
Noncontrolling interests	78.7	79.6
Total Partners' Capital	<u>6,691.3</u>	<u>6,724.1</u>
Total Liabilities and Partners' Capital	<u>\$ 20,653.5</u>	<u>\$ 20,262.2</u>

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)

	Three Months Ended March 31,	
	2010	2009
Cash Flows From Operating Activities		
Net Income.....	\$ 227.4	\$ 266.8
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	227.3	210.2
Amortization of excess cost of equity investments	1.4	1.4
Income from the allowance for equity funds used during construction.....	(0.5)	(9.3)
Income from the sale or casualty of property, plant and equipment and other net assets	(1.3)	(0.9)
Earnings from equity investments.....	(46.7)	(38.2)
Distributions from equity investments.....	49.8	56.5
Proceeds from termination of interest rate swap agreements.....	-	144.4
Changes in components of working capital:		
Accounts receivable.....	49.0	210.6
Inventories	(7.5)	(4.3)
Other current assets.....	23.8	3.3
Accounts payable.....	(9.1)	(246.9)
Accrued interest.....	(127.8)	(86.5)
Accrued taxes	6.1	16.7
Accrued liabilities.....	(12.4)	(56.6)
Rate reparations, refunds and other litigation reserve adjustments	158.0	-
Other, net	(22.7)	(14.8)
Net Cash Provided by Operating Activities.....	514.8	452.4
Cash Flows From Investing Activities		
Acquisitions of assets and investments.....	(226.3)	(0.5)
Repayments from customers	-	98.1
Capital expenditures.....	(218.8)	(420.3)
Sale or casualty of property, plant and equipment, and other net assets net of removal costs.....	13.4	(1.4)
Net proceeds from (Investments in) margin deposits	15.9	(5.8)
Contributions to equity investments	(135.6)	(173.5)
Distributions from equity investments in excess of cumulative earnings	57.3	-
Net Cash Used in Investing Activities.....	(494.1)	(503.4)
Cash Flows From Financing Activities		
Issuance of debt.....	957.0	913.8
Payment of debt	(524.0)	(725.7)
Repayments from related party	-	1.2
Debt issue costs.....	(0.2)	(0.4)
Increase (Decrease) in cash book overdrafts	10.8	(2.9)
Proceeds from issuance of common units.....	-	287.9
Contributions from noncontrolling interests	1.7	3.8
Distributions to partners and noncontrolling interests:		
Common units	(217.7)	(192.3)
Class B units.....	(5.6)	(5.6)
General Partner.....	(245.5)	(219.4)
Noncontrolling interests.....	(6.0)	(5.4)
Other, net	-	(0.1)
Net Cash (Used in) Provided by Financing Activities.....	(29.5)	54.9
Effect of Exchange Rate Changes on Cash and Cash Equivalents	(3.4)	(0.9)
(Decrease) Increase in Cash and Cash Equivalents	(12.2)	3.0
Cash and Cash Equivalents, beginning of period	146.6	62.5
Cash and Cash Equivalents, end of period	\$ 134.4	\$ 65.5
Noncash Investing and Financing Activities		
Assets acquired by the assumption or incurrence of liabilities	\$ 10.5	\$ -
Assets acquired by the issuance of common units.....	\$ 81.7	\$ -
Supplemental Disclosures of Cash Flow Information		
Cash paid during the period for interest (net of capitalized interest)	\$ 213.5	\$ 187.2
Cash paid during the period for income taxes	\$ 2.7	\$ 3.5

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 like 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., discussed following.

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

Kinder Morgan, Inc., referred to as KMI in this report, is a Kansas corporation privately owned by investors led by Richard D. Kinder, Chairman and Chief Executive Officer of both Kinder Morgan G.P., Inc. (our general partner) and Kinder Morgan Management, LLC (our general partner’s delegate). KMI has been privately owned since its merger with Kinder Morgan Holdco LLC on May 30, 2007. This merger is referred to in this report as the going-private transaction and is described more fully in Note 1 to our consolidated financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2009, referred to in this report as our 2009 Form 10-K.

KMI indirectly owns all the common stock of our general partner. 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.

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. More information on these entities and the delegation of control agreement is contained in our 2009 Form 10-K.

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 presentation 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 2009 Form 10-K.

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

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 per Unit

We compute Limited Partners’ Net Income per Unit by dividing our limited partners’ interest in net income by the weighted average number of units outstanding during the period. The overall computation, presentation, and disclosure requirements for our Limited Partners’ Net Income per Unit are made in accordance with the “Earnings per Share” Topic of the Codification. Among other things, this Topic contains (i) master limited partnership subsections that provide guidance for how current period earnings should be allocated between limited partners and a general partner when the partnership agreement contains incentive distribution rights; and (ii) provisions which clarify that share-based payment awards that entitle their holders to receive nonforfeitable dividends before vesting should be considered participating securities. As participating securities, these instruments should be included in the calculation of basic earnings per share.

2. Acquisitions, Joint Venture Contributions, and Divestitures

Acquisitions

USD Terminal Acquisition

On January 15, 2010, we acquired three ethanol handling train terminals from US Development Group LLC for an aggregate consideration of \$200.8 million, consisting of \$115.7 million in cash, \$81.7 million in common units, and \$3.4 million in assumed liabilities. The three train terminals are located in Linden, New Jersey; Baltimore, Maryland; and Dallas, Texas. As part of the transaction, we announced the formation of a venture with US Development Group LLC to optimize and coordinate customer access to the three acquired terminals, other ethanol terminal assets we already own and operate, and other terminal projects currently under development by both parties. The acquisition complemented and expanded the ethanol and rail terminal operations we previously owned, and all of the acquired assets are included in our Terminals business segment.

Based on our measurement of fair market values for all of the identifiable tangible and intangible assets acquired and liabilities assumed on the acquisition date, we assigned \$94.6 million of our combined purchase price to “Other intangibles, net” (representing customer relationships); \$43.1 million to “Property, Plant and Equipment, net”; and a combined \$5.1 million to “Other current assets” and “Deferred charges and other assets.” The remaining \$58.0 million of our purchase price represented the future economic benefits expected to be derived from the acquisition that was not assigned to other identifiable, separately recognizable assets acquired, and we recorded this amount as “Goodwill.” We believe the primary items that generated the goodwill are the value of the synergies created between the acquired assets and our pre-existing ethanol handling assets, and our expected ability to grow the business by leveraging our pre-existing experience in ethanol handling operations. We expect that the entire amount of goodwill will be deductible for tax purposes.

Slay Industries Terminal Acquisition

On March 5, 2010, we acquired certain bulk and liquids terminal assets from Slay Industries for an aggregate consideration of \$104.0 million, consisting of \$97.0 million in cash, assumed liabilities of \$1.7 million, and an obligation to pay additional cash consideration in years 2013 through 2019, contingent upon the purchased assets providing us an agreed-upon amount of earnings during the three years following the closing. As of the acquisition date, the contingent consideration had a fair value of \$5.3 million, and we expect to pay approximately \$4.6 million of this liability in the first half of 2013.

The acquired assets include (i) a marine terminal located in Sauget, Illinois; (ii) a transload liquid operation located in Muscatine, Iowa; (iii) a liquid bulk terminal located in St. Louis, Missouri; and (iv) a warehousing distribution center located in St. Louis. All of the acquired terminals have long-term contracts with large creditworthy shippers. As part of

the transaction, we and Slay Industries entered into joint venture agreements at both the Kellogg Dock coal bulk terminal, located in Modoc, Illinois, and at the newly created North Cahokia terminal, located in Sauget and which has approximately 175 acres of land ready for development. All of the assets located in Sauget have access to the Mississippi River and are served by five rail carriers. The acquisition complemented and expanded our pre-existing Midwest terminal operations by adding a diverse mix of liquid and bulk capabilities, and all of the acquired assets are included in our Terminals business segment.

Based on our measurement of fair market values for all of the identifiable tangible and intangible assets acquired and liabilities assumed on the acquisition date, we assigned \$67.9 million of our purchase price to “Property, Plant and Equipment, net”; \$27.0 million to “Other intangibles, net” (representing customer contracts); and a combined \$8.2 million to “Investments.” We recorded the remaining \$0.9 million of our combined purchase price as “Goodwill,” representing certain advantageous factors that contributed to our acquisition price exceeding the fair value of acquired identifiable net assets—in the aggregate, these factors represented goodwill, and we expect that the entire amount of goodwill will be deductible for tax purposes.

Mission Valley Terminal Acquisition

On March 1, 2010, we acquired the refined products terminal assets at Mission Valley, California from Equilon Enterprises LLC (d/b/a Shell Oil Products US) for \$13.5 million in cash. The acquired assets include buildings, equipment, delivery facilities (including two truck loading racks), and storage tanks with a total capacity of approximately 170,000 barrels for gasoline, diesel fuel and jet fuel. The terminal operates under a long-term terminaling agreement with Tesoro Refining and Marketing Company. We assigned our entire purchase price to “Property, Plant and Equipment, net.” The acquisition enhanced our Pacific operations and complemented our existing West Coast terminal operations, and the acquired assets are included in our Products Pipelines 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 March 31, 2010

On April 13, 2010, we announced that we had entered into a definitive agreement to purchase a 50% ownership interest in Petrohawk Energy Corporation’s natural gas gathering and treating business in the Haynesville shale gas formation located in northwest Louisiana for \$875 million in cash. The assets consist of more than 170 miles of pipeline currently in service, and it is expected that the pipeline mileage will increase to approximately 375 miles with projected throughput of over 800 million cubic feet per day of natural gas by the end of 2010. Additionally, it is expected that the system’s natural gas amine treating plants will have capacity of approximately 2,635 gallons per minute by the end of 2010. Closing of the transaction is subject to customary closing conditions and is expected to occur by the end of May 2010.

Petrohawk will continue to operate the business during a short transition period, and following the transition period, the newly formed company named KinderHawk Field Services LLC, owned 50% by us and 50% by Petrohawk, will assume the joint venture operations. KinderHawk Field Services LLC has also received a dedication to transport and treat all of Petrohawk’s operated Haynesville and Bossier shale gas production in Louisiana for the life of the leases at agreed upon rates, as well as minimum volume commitments from Petrohawk for the first five years of the joint venture agreement. It will also focus on providing firm transportation services to third-party producers. The joint venture ultimately is expected to have approximately two billion cubic feet per day of mainline throughput capacity, which will make it one of the largest gathering and treating systems in the United States. The acquisition will complement and expand our existing natural gas gathering and treating businesses, and all of the acquired assets will be included as part of our Natural Gas Pipelines business segment.

Joint Venture (Equity Investment) Contributions

During the first quarter of 2010, we contributed \$135.6 million to our equity investees, including contributions of \$130.5 million to Rockies Express Pipeline LLC. We operate and own a 50% equity interest in Rockies Express Pipeline

LLC (the surviving legal entity from its December 30, 2009 merger with its parent entity, West2East Pipeline LLC), and Rockies Express used the contributions as partial funding for its Rockies Express natural gas pipeline system construction costs and for other corporate purposes.

In the first quarter of 2009, our equity investment contributions totaled \$173.5 million, including contributions of \$111.0 million to Midcontinent Express Pipeline LLC and \$51.0 million to West2East Pipeline LLC to partially fund construction costs for the Midcontinent Express and the Rockies Express natural gas pipeline systems, respectively. We also made a \$9.0 million capital contribution to Fayetteville Express Pipeline LLC to partially fund certain pre-construction pipeline costs for its Fayetteville Express natural gas pipeline system. We own a 50% equity interest in both Midcontinent Express Pipeline LLC and Fayetteville Express Pipeline LLC. We report our equity contributions separately as "Contributions to equity investments" in our accompanying consolidated statement of cash flows for the three months ended March 31, 2010 and 2009.

Divestitures

Cypress Pipeline

On July 14, 2009, we received notice from Westlake Petrochemicals LLC, a wholly-owned subsidiary of Westlake Chemical Corporation, that it was exercising an option it held to purchase a 50% ownership interest in our Cypress Pipeline. We expect the transaction to close by the end of the second quarter of 2010. As of March 31, 2010, the net assets of our Cypress Pipeline totaled approximately \$21.0 million. At the time of the sale, we will (i) deconsolidate the net assets of the Cypress Pipeline; (ii) recognize a gain or loss on the sale of net assets equal to the difference between (a) the proceeds received from the sale, and (b) 50% of the net assets' carrying value; and (iii) recognize the remaining 50% noncontrolling investment retained at its fair value (which is expected to result in a gain).

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); (iii) Natural Gas Pipelines; (iv) CO₂; (v) Terminals; and (vi) Kinder Morgan Canada.

There were no impairment charges resulting from our May 31, 2009 impairment testing, and no event indicating an impairment has occurred 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 9.0%. 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 three months ended March 31, 2010 are summarized as follows (in millions):

	Products Pipelines	Natural Gas Pipelines	CO₂	Terminals	Kinder Morgan Canada	Total
Balance as of December 31, 2009						
Goodwill.....	\$ 263.2	\$ 337.0	\$ 46.1	\$ 266.9	\$ 613.1	\$ 1,526.3
Accumulated impairment losses(a)....	-	-	-	-	(377.1)	(377.1)
	<u>263.2</u>	<u>337.0</u>	<u>46.1</u>	<u>266.9</u>	<u>236.0</u>	<u>1,149.2</u>
Acquisitions.....	-	-	-	58.9	-	58.9
Disposals.....	-	-	-	-	-	-
Impairments.....	-	-	-	-	-	-
Currency translation adjustments.....	-	-	-	-	8.1	8.1
Balance as of March 31, 2010						
Goodwill.....	263.2	337.0	46.1	325.8	621.2	1,593.3
Accumulated impairment losses.....	-	-	-	-	(377.1)	(377.1)
	<u>\$ 263.2</u>	<u>\$ 337.0</u>	<u>\$ 46.1</u>	<u>\$ 325.8</u>	<u>\$ 244.1</u>	<u>\$ 1,216.2</u>

(a) On April 18, 2007, we announced that we would acquire the Trans Mountain pipeline system from KMI, and this transaction was completed April 30, 2007. Following the provisions of 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 reflected in our accumulated impairment losses above.

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. 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 three months of 2010, and as of both March 31, 2010 and December 31, 2009, we reported \$138.2 million 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):

	March 31, 2010	December 31, 2009
Customer relationships, contracts and agreements		
Gross carrying amount.....	\$ 394.6	\$ 273.0
Accumulated amortization.....	(78.2)	(67.1)
Net carrying amount.....	<u>316.4</u>	<u>205.9</u>
Technology-based assets, lease value and other		
Gross carrying amount.....	15.7	15.7
Accumulated amortization.....	(3.1)	(2.9)
Net carrying amount.....	<u>12.6</u>	<u>12.8</u>
Total Other intangibles, net.....	<u>\$ 329.0</u>	<u>\$ 218.7</u>

The increase in the carrying amount of our customer relationships, contracts and agreements since December 31, 2009 was mainly due to the acquisition of intangibles included in our purchase of terminal assets from US Development Group LLC and Slay Industries, 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 effect of obsolescence, new technology, and competition. For the three months ended March 31, 2010 and 2009, the amortization expense on our intangibles totaled \$11.3 million and \$3.5 million, respectively. As of March 31, 2010, the weighted average amortization period for all of our intangible assets combined was approximately 14 years, and the weighted average amortization period for the intangible assets we acquired from US Development Group LLC and Slay Industries in the first quarter of 2010 was approximately 11.7 years. Our estimated amortization expense for all of our intangible assets for each of the next five fiscal years (2011 – 2015) is approximately \$38.9 million, \$33.5 million, \$29.5 million, \$26.4 million and \$23.4 million, respectively.

4. Debt

We classify our debt based on the contractual maturity dates of the underlying debt instruments or as of the earliest put date available to the holders of the applicable debt. We defer costs associated with debt issuance over the applicable term or to the first put date, in the case of debt with a put feature. 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 March 31, 2010 and December 31, 2009 was \$11,016.4 million and \$10,592.4 million, respectively, and the weighted average interest rate on all of our borrowings was approximately 4.32% during the first quarter of 2010, and approximately 5.11% during the first quarter of 2009.

Our outstanding short-term debt as of March 31, 2010 was \$1,734.4 million. The balance consisted of (i) \$700.0 million in principal amount of 6.75% senior notes due March 15, 2011 (including discount, the notes had a carrying amount of \$699.8 million as of March 31, 2010); (ii) \$675.0 million in outstanding borrowings under our unsecured revolving bank credit facility; (iii) \$250.0 million in principal amount of 7.50% senior notes due November 1, 2010; (iv) \$65.0 million of commercial paper borrowings; (v) \$23.7 million in principal amount of tax-exempt bonds that mature on April 1, 2024, but 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); (vi) a \$9.0 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); (vii) a \$6.9 million portion of 5.23% senior notes (our subsidiary Kinder Morgan Texas Pipeline, L.P. is the obligor on the notes); and (viii) \$5.0 million in principal amount of 6.00% Development Revenue Bonds issued by the Louisiana Community Development Authority, a political subdivision of the state of Louisiana (our subsidiary Kinder Morgan Louisiana Pipeline LLC is the obligor on the bonds).

Credit Facility

Our \$1.79 billion unsecured bank credit facility is with a syndicate of financial institutions, and Wells Fargo Bank, National Association is the administrative agent. The credit facility permits us to obtain bids for fixed rate loans from members of the lending syndicate, and the facility can be amended to allow for borrowings of up to \$2.04 billion. Interest on our credit facility accrues at our option at a floating rate equal to either (i) the administrative agent’s base rate (but not less than the Federal Funds Rate, plus 0.5%); or (ii) LIBOR, plus a margin, which varies depending upon the credit rating of our long-term senior unsecured debt. Borrowings under our credit facility can be used for partnership purposes and as a backup for our commercial paper program.

The outstanding balance under our credit facility was \$675 million as of March 31, 2010, and the average interest rate on these borrowings was 0.58%. As of December 31, 2009, the outstanding balance under our credit facility was \$300 million, and the average interest rate on these borrowings was 0.59%. Our credit facility matures August 18, 2010, and we plan to negotiate a renewal of the credit facility before its maturity date.

Additionally, as of March 31, 2010, the amount available for borrowing under our credit facility was reduced by a combined amount of \$318.3 million, consisting of commercial paper borrowings of \$65.0 million and \$253.3 million of letters of credit, consisting of: (i) a \$100 million letter of credit that supports certain proceedings with the California Public Utilities Commission involving refined products tariff charges on the intrastate common carrier operations of our Pacific operations’ pipelines in the state of California; (ii) a combined \$89.4 million in three letters of credit that support tax-exempt bonds; (iii) a combined \$25.5 million in two letters of credit that support our hedging of commodity price risks associated with the sale of natural gas, natural gas liquids and crude oil; (iv) a \$21.4 million letter of credit that supports our indemnification obligations on the Series D note borrowings of Cortez Capital Corporation; and (v) a combined \$17.0 million in other letters of credit supporting other obligations of us and our subsidiaries.

Commercial Paper Program

On October 13, 2008, Standard & Poor's Ratings Services lowered our short-term credit rating to A-3 from A-2, and on May 6, 2009, Moody's Investors Service, Inc. downgraded our commercial paper rating to Prime-3 from Prime-2 and assigned a negative outlook to our long-term credit rating. As a result of these revisions and the commercial paper market conditions, we were unable to access commercial paper borrowings throughout 2009.

However, on February 25, 2010, Standard & Poor's revised its outlook on our long-term credit rating to stable from negative, affirmed our long-term credit rating at BBB, and raised our short-term credit rating to A-2 from A-3. The rating agency's revisions reflected its expectations that our financial profile will improve due to lower guaranteed debt obligations and higher expected cash flows associated with the completion and start-up of our 50%-owned Rockies Express and Midcontinent Express natural gas pipeline systems and our fully-owned Kinder Morgan Louisiana natural gas pipeline system. Due to this favorable change in our short-term credit rating, we resumed issuing commercial paper in March 2010, and as of March 31, 2010, we had \$65.0 million of commercial paper outstanding with an average interest rate of approximately 0.49%. However, in the near term, we expect that most of our financing and our short-term liquidity needs will continue to be met primarily through borrowings made under our bank credit facility.

Arrow Terminals L.P. Debt

On January 1, 2010, our subsidiary Arrow Terminals L.P. paid the \$5.3 million outstanding principal amount of its Adjustable Rate Industrial Development Revenue Bonds issued by the Illinois Development Finance Authority that matured on that date, and following its repayment, Arrow Terminals L.P. had no outstanding 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. As of December 31, 2009, the net present value (representing the outstanding balance on our balance sheet) of the note was \$28.1 million. We paid the third installment on March 31, 2010, and as of this date, the net present value of the note was \$18.5 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 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. In the first quarter of 2010, we paid a combined principal amount of \$1.7 million, and as of March 31, 2010, Kinder Morgan Texas Pipeline L.P.'s outstanding balance under the senior notes was \$28.8 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.

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. The following is a description of our contingent debt agreements as of March 31, 2010.

Cortez Pipeline Company Debt

Pursuant to a Throughput and Deficiency Agreement, the partners of Cortez Pipeline Company (our subsidiary Kinder Morgan CO₂ Company, L.P. – 50% partner; a subsidiary of Exxon Mobil Corporation – 37% partner; and Cortez Vickers Pipeline Company – 13% partner) are required, on a several, proportional percentage ownership basis, to contribute capital to Cortez Pipeline Company in the event of a cash deficiency. Furthermore, due to our indirect ownership of Cortez Pipeline Company through Kinder Morgan CO₂ Company, L.P., we severally guarantee 50% of the debt of Cortez Capital Corporation, a wholly-owned subsidiary of Cortez Pipeline Company.

As of March 31, 2010, the debt facilities of Cortez Capital Corporation consisted of (i) \$42.9 million of fixed rate Series D notes due May 15, 2013; (ii) \$100 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 LIBOR plus a spread); and (iii) a \$40 million committed revolving credit facility also due December 11, 2012. As of March 31, 2010, in addition to the outstanding Series D and Series E notes, Cortez Capital Corporation had outstanding borrowings of \$6.3 million under its credit facility. Accordingly, as of March 31, 2010, our contingent share of Cortez's debt was \$74.6 million (50% of total borrowings).

With respect to Cortez's Series D notes, the average interest rate on the notes is 7.14%, and the outstanding \$42.9 million principal amount of the notes is due in four equal annual installments of approximately \$10.7 million beginning May 2010. Shell Oil Company shares our several guaranty obligations jointly and severally; however, we are obligated to indemnify Shell for liabilities it incurs in connection with such guaranty. Accordingly, as of March 31, 2010, JP Morgan Chase has issued a letter of credit on our behalf in the amount of \$21.4 million to secure our indemnification obligations to Shell for 50% of the \$42.9 million in principal amount of Series D notes outstanding as of that date.

Nassau County, Florida Ocean Highway and Port Authority Debt

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 March 31, 2010, this letter of credit had a face amount of \$19.8 million.

Rockies Express Pipeline LLC Debt

Rockies Express Pipeline LLC is an equity method investee of ours, and pursuant to certain guaranty agreements remaining in effect on March 31, 2010, all three member owners of Rockies Express Pipeline LLC had agreed to guarantee, severally in the same proportion as their percentage ownership of the member interests in Rockies Express Pipeline LLC, borrowings under its \$2.0 billion five-year, unsecured revolving bank credit facility. Borrowings under the credit facility can be used for general corporate purposes, and the credit facility is due April 28, 2011. As of March 31, 2010, the credit facility could be amended to allow for borrowings of up to \$2.5 billion. The three member owners and their respective ownership interests consist of the following: our subsidiary Kinder Morgan W2E Pipeline LLC – 50%; a subsidiary of Sempra Energy – 25%; and a subsidiary of ConocoPhillips – 25%.

On March 22, 2010, Rockies Express Pipeline LLC completed a private offering of an aggregate of \$1.7 billion in principal amount of fixed rate senior notes. After deducting the initial purchasers' discounts and offering expenses, Rockies Express received net proceeds of approximately \$1.69 billion from this offering, and the net proceeds from the sale of these notes were used to repay all of the borrowings under its bank credit facility. Accordingly, as of March 31, 2010, we had no contingent debt obligation associated with our guaranty agreement with Rockies Express Pipeline LLC.

All payments of principal and interest in respect of these fixed rate senior notes are the sole obligation of Rockies Express Pipeline LLC. Noteholders will have no recourse against us, Sempra Energy or ConocoPhillips, or against any of our or their respective officers, directors, employees, shareholders, members, managers, unitholders or affiliates for any failure by Rockies Express to perform or comply with its obligations pursuant to the notes or the indenture.

Subsequent Event

On April 8, 2010, Rockies Express Pipeline LLC amended its bank credit facility to allow for borrowings up to \$200 million (a reduction from \$2.0 billion), and on this same date, each of its three member owners were released from their respective debt obligations under the previous guaranty agreements. Accordingly, we no longer have a contingent debt obligation with respect to Rockies Express Pipeline LLC.

Midcontinent Express Pipeline LLC Debt

Midcontinent Express Pipeline LLC is also an equity method investee of ours, and the two member owners and their respective ownership interests consist of the following: our subsidiary Kinder Morgan Operating L.P. "A" – 50%; and Energy Transfer Partners, L.P. – 50%. Pursuant to certain guaranty agreements, both of the member owners of Midcontinent Express Pipeline LLC have agreed to guarantee, severally in the same proportion as their percentage ownership of the member interests in Midcontinent Express Pipeline LLC, borrowings under its \$255.4 million three-year, unsecured revolving credit facility due February 28, 2011. The facility is with a syndicate of financial institutions with The Royal Bank of Scotland plc as the administrative agent.

Borrowings under the credit facility can be used for general limited liability company purposes, and as of March 31, 2010, Midcontinent Express Pipeline LLC had outstanding borrowings of \$89.0 million under its bank credit facility. Accordingly, as of March 31, 2010, our contingent share of Midcontinent Express' debt was \$44.5 million (50% of total guaranteed borrowings). Furthermore, the credit facility can be used for the issuance of letters of credit to support the operation of the Midcontinent Express pipeline system, and as of March 31, 2010, a letter of credit having a face amount of \$33.3 million was issued under the credit facility by the Bank of Tokyo-Mitsubishi UFJ, Ltd. Accordingly, as of March 31, 2010, our contingent responsibility with regard to this outstanding letter of credit was \$16.7 million (50% of total face amount).

Subsequent Event

On April 28, 2010, Midcontinent Express Pipeline LLC announced that it intended to amend its bank credit facility to allow for borrowings up to \$175.4 million (a reduction from \$255.4 million). We expect this amendment to become effective in May 2010.

Fayetteville Express Pipeline LLC Debt

Pursuant to certain guaranty agreements with Fayetteville Express Pipeline LLC, a third equity method investee of ours, both of the member owners of Fayetteville Express Pipeline LLC have agreed to guarantee, severally in the same proportion as their percentage ownership of the member interests in Fayetteville Express, borrowings under its \$1.1 billion, unsecured revolving credit facility that is due May 11, 2012. The two member owners and their respective ownership interests consist of the following: our subsidiary Kinder Morgan Operating L.P. "A" – 50%; and Energy Transfer Partners, L.P. – 50%.

The Fayetteville Express Pipeline LLC credit facility is with a syndicate of financial institutions with The Royal Bank of Scotland plc as the administrative agent. Borrowings under the credit facility will be used to finance the construction of the Fayetteville Express natural gas pipeline system and to pay related expenses. As of March 31, 2010, Fayetteville Express had outstanding borrowings of \$468.0 million under its bank credit facility. Accordingly, as of March 31, 2010, our contingent share of Fayetteville Express' debt was \$234.0 million (50% of total borrowings).

For additional information regarding our debt facilities and our contingent debt agreements, see Note 8 and Note 12 to our consolidated financial statements included in our 2009 Form 10-K.

5. Partners' Capital

Limited Partner Units

As of March 31, 2010 and December 31, 2009, our partners' capital included the following limited partner units:

	March 31, 2010	December 31, 2009
Common units.....	207,310,563	206,020,826
Class B units	5,313,400	5,313,400
i-units	87,114,733	85,538,263
Total limited partner units	<u>299,738,696</u>	<u>296,872,489</u>

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 incentive distribution rights.

As of March 31, 2010, our total common units consisted of 190,940,135 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, 2009, our total common units consisted of 189,650,398 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 March 31, 2010 and December 31, 2009, 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 March 31, 2010 and December 31, 2009, 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 month periods ended March 31, 2010 and 2009, changes in the carrying amounts of our Partners' Capital attributable to both us and our noncontrolling interests, including our comprehensive income (loss) are summarized as follows (in millions):

	Three Months Ended March 31,					
	2010			2009		
	KMP	Noncontrolling interests	Total	KMP	Noncontrolling interests	Total
Beginning Balance	\$ 6,644.5	\$ 79.6	\$ 6,724.1	\$ 6,045.6	\$ 70.7	\$ 6,116.3
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.....	81.7	-	81.7	-	-	-
Units issued for cash.....	-	-	-	287.6	-	287.6
Distributions paid in cash.....	(468.8)	(6.0)	(474.8)	(417.3)	(5.4)	(422.7)
Adjustments to capital resulting from related party acquisitions.....	-	-	-	2.7	-	2.7
KMI going-private transaction expenses.....	1.4	-	1.4	1.4	-	1.4
Cash contributions.....	-	1.7	1.7	-	3.8	3.8
Comprehensive income (loss):						
Net Income.....	225.3	2.1	227.4	263.9	2.9	266.8
Other comprehensive loss:						
Change in fair value of derivatives utilized for hedging purposes.....	24.4	0.2	24.6	35.5	0.4	35.9
Reclassification of change in fair value of derivatives to net income.....	47.0	0.5	47.5	(17.1)	(0.2)	(17.3)
Foreign currency translation adjustments.....	59.2	0.6	59.8	(54.2)	(0.6)	(54.8)
Adjustments to pension and other postretirement benefit plan liabilities.....	(2.3)	-	(2.3)	(2.8)	-	(2.8)
Total other comprehensive income (loss).....	128.3	1.3	129.6	(38.6)	(0.4)	(39.0)
Comprehensive income.....	353.6	3.4	357.0	225.3	2.5	227.8
Ending Balance	<u>\$ 6,612.6</u>	<u>\$ 78.7</u>	<u>\$ 6,691.3</u>	<u>\$ 6,145.5</u>	<u>\$ 71.6</u>	<u>\$ 6,217.1</u>

During the first three months of both 2010 and 2009, there were no material changes in our ownership interests in subsidiaries in which we retained a controlling financial interest.

Equity Issuances

On January 15, 2010, we issued 1,287,287 common units as part of our purchase price for the ethanol handling terminal assets we acquired from US Development Group LLC. We valued the common units at \$81.7 million, determining the units' value based on the \$63.45 closing market price of the common units on the New York Stock Exchange on the January 15, 2010 acquisition date. For more information on this acquisition, see Note 2 "Acquisitions, Joint Venture Contributions, and Divestitures—Acquisitions—USD Terminal Acquisition."

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.

On February 12, 2010, we paid a cash distribution of \$1.05 per unit to our common unitholders and our Class B unitholders for the quarterly period ended December 31, 2009. KMR, our sole i-unitholder, received a distribution of 1,576,470 i-units from us on February 12, 2010, based on the \$1.05 per unit distributed to our common unitholders on that date. The distributions were declared on January 20, 2010, payable to unitholders of record as of January 29, 2010.

On April 21, 2010, we declared a cash distribution of \$1.07 per unit for the quarterly period ended March 31, 2010. The distribution will be paid on May 14, 2010, to unitholders of record as of April 30, 2010. Our common unitholders and Class B unitholders will receive cash. KMR will receive a distribution of 1,556,130 additional i-units based on the \$1.07 distribution per common unit. For each outstanding i-unit that KMR holds, a fraction of an i-unit (0.017863) will be issued. This fraction was determined by dividing:

- \$1.07, the cash amount distributed per common unit

by

- \$59.90, the average of KMR's shares' closing market prices from April 14-27, 2010, 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.

Incentive distributions allocated to our general partner are determined by the amount quarterly distributions to unitholders exceed certain specified target levels, according to the provisions of our partnership agreement. Our distribution of \$1.05 per unit paid on February 12, 2010 for the fourth quarter of 2009 required an incentive distribution to our general partner of \$242.3 million. Our distribution of \$1.05 per unit paid on February 13, 2009 for the fourth quarter of 2008 resulted in an incentive distribution payment to our general partner in the amount of \$216.6 million. The increased incentive distribution to our general partner paid for the fourth quarter of 2009 over the incentive distribution paid for the fourth quarter of 2008 reflects the issuance of additional units.

Our declared distribution for the first quarter of 2010 of \$1.07 per unit will result in an incentive distribution to our general partner of \$249.4 million. This compares to our distribution of \$1.05 per unit and incentive distribution to our general partner of \$223.2 million for the first quarter of 2009.

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 unfavorable 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. The unfavorable 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 generally accepted accounting principles, the portion of the gain or loss on the derivative contract that is effective 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), 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. In the first quarter of 2010, we recognized a net gain of \$6.3 million related to crude oil and natural gas hedges, which resulted from hedge ineffectiveness and amounts excluded from effectiveness testing.

Additionally, during the three months ended March 31, 2010 and 2009, we reclassified a loss of \$47.5 million and a gain of \$17.3 million, respectively, from "Accumulated other comprehensive loss" into earnings. All amounts reclassified into net income during the first quarter of both years resulted from the hedged forecasted transactions actually affecting earnings (i.e., when the forecasted sales and purchases actually occurred). No 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 not occur by the end of the originally specified time period or within an additional two-month period of time thereafter. 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 was \$266.5 million as of March 31, 2010, and \$394.8 million as of December 31, 2009. These totals included "Accumulated other comprehensive loss" amounts associated with energy commodity price risk management activities of \$346.8 million as of March 31, 2010 and \$418.2 million as of December 31, 2009. Approximately \$211.1 million of the total loss amount associated with energy commodity price risk management activities and included in our Partners' Capital as of March 31, 2010 is expected to be reclassified into earnings during the next twelve months (when the associated forecasted sales and purchases are also expected to occur), and as of March 31, 2010, 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 2014.

As of March 31, 2010, we had entered into the following outstanding commodity forward contracts to hedge our forecasted energy commodity purchases and sales:

	<u>Notional quantity</u>
Derivatives designated as hedging contracts	
Crude oil.....	23.9 million barrels
Natural gas(a).....	69.8 billion cubic feet
Derivatives not designated as hedging contracts	
Natural gas(a).....	0.1 billion cubic feet

(a) Notional quantities are shown net.

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. 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 both March 31, 2010 and December 31, 2009, we had a combined notional principal amount of \$5.2 billion 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 March 31, 2010, 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.

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 March 31, 2010 and December 31, 2009 (in millions):

Fair Value of Derivative Contracts

	Asset derivatives				Liability derivatives			
	March 31, 2010		December 31, 2009		March 31, 2010		December 31, 2009	
	Balance sheet location	Fair value	Balance sheet location	Fair value	Balance Sheet location	Fair value	Balance sheet location	Fair Value
<u>Derivatives designated as hedging contracts</u>								
Energy commodity derivative contracts	Current	\$ 52.6	Current	\$ 19.1	Current	\$ (273.1)	Current	\$ (270.8)
	Non-current	53.6	Non-current	57.3	Non-current	(190.4)	Non-current	(241.5)
Subtotal		106.2		76.4		(463.5)		(512.3)
Interest rate swap agreements	Non-current	243.6	Non-current	222.5	Non-current	(174.0)	Non-current	(218.6)
Total		349.8		298.9		(637.5)		(730.9)
<u>Derivatives not designated as hedging contracts</u>								
Energy commodity derivative contracts	Current	6.0	Current	1.7	Current	(5.1)	Current	(1.2)
	Non-current	0.1	Non-current	-	Non-current	(0.9)	Non-current	-
Total		6.1		1.7		(6.0)		(1.2)
Total derivatives		<u>\$ 355.9</u>		<u>\$ 300.6</u>		<u>\$ (643.5)</u>		<u>\$ (732.1)</u>

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 March 31, 2010 and December 31, 2009, this unamortized premium totaled \$324.0 million and \$328.6 million, respectively.

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 months ended March 31, 2010 and 2009 (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)		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 items(a)	
		Three Months Ended March 31,				Three Months Ended March 31,	
		2010	2009			2010	2009
Interest rate swap agreements	Interest, net – income/(expense)	\$ 65.6	\$ (130.4)	Fixed rate debt	Interest, net – income/(expense)	\$ (65.6)	\$ 130.4
Total		\$ 65.6	\$ (130.4)	Total		\$ (65.6)	\$ 130.4

(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) reclassified 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 March 31,			Three Months Ended March 31,			Three Months Ended March 31,	
	2010	2009		2010	2009		2010	2009
Energy commodity derivative contracts	\$ 24.6	\$ 35.9	Revenues-natural gas sales	\$ -	\$ 1.7	Revenues	\$ 5.4	\$ -
			Revenues-product sales and other	(50.0)	16.0			
			Gas purchases and other costs of sales	2.5	(0.4)	Gas purchases and other costs of sales	0.9	-
Total	\$ 24.6	\$ 35.9	Total	\$ (47.5)	\$ 17.3	Total	\$ 6.3	\$ -

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 March 31,	
		2010	2009
Energy commodity derivative contracts	Gas purchases and other costs of sales	\$ 0.7	\$ (0.4)
Total		\$ 0.7	\$ (0.4)

Credit Risks

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

We maintain credit policies with regard to our counterparties that we believe minimize our overall credit risk. These policies include (i) an evaluation of potential counterparties' financial condition (including credit ratings); (ii) collateral

requirements under certain circumstances; and (iii) the use of standardized agreements which allow for netting of positive and negative exposure associated with a single counterparty. Based on our policies, exposure, credit and other reserves, our management does not anticipate a material adverse effect on our financial position, results of operations, or cash flows as a result of counterparty performance.

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

The maximum potential exposure to credit losses on our derivative contracts as of March 31, 2010 was (in millions):

	<u>Asset position</u>
Interest rate swap agreements	\$ 243.6
Energy commodity derivative contracts	112.3
Gross exposure	355.9
Netting agreement impact	(76.8)
Net exposure	<u>\$ 279.1</u>

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 March 31, 2010 and December 31, 2009, we had outstanding letters of credit totaling \$25.5 million and \$55.0 million, respectively, in support of our hedging of energy commodity price risks associated with the sale of natural gas, natural gas liquids and crude oil.

Additionally, as of March 31, 2010, our counterparties associated with our energy commodity contract positions and over-the-counter swap agreements had margin deposits with us totaling \$0.7 million, and we reported this amount within "Accrued other liabilities" in our accompanying consolidated balance sheet. As of December 31, 2009, we had cash margin deposits associated with our energy commodity contract positions and over-the-counter swap partners totaling \$15.2 million, and we reported these amounts as "Restricted deposits" in our accompanying consolidated balance sheet.

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 March 31, 2010, we estimate that if our credit rating was downgraded, we would have the following additional collateral obligations (in millions):

<u>Credit ratings downgraded(a)</u>	<u>Incremental obligations</u>	<u>Cumulative obligations(b)</u>
One notch to BBB-/Baa3	\$ 19.0	\$ 44.5
Two notches to below BBB-/Baa3 (below investment grade)	\$ 115.2	\$ 159.7

(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 one notch downgrade to BBB-/Baa3 by one agency would not trigger the entire \$19.0 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 March 31, 2010 and December 31, 2009, based on the three levels established by the Codification (in millions):

	Asset fair value measurements using			
	Total	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
As of March 31, 2010				
Energy commodity derivative contracts(a)	\$ 112.3	\$ -	\$ 53.5	\$ 58.8
Interest rate swap agreements	\$ 243.6	\$ -	\$ 243.6	\$ -
As of December 31, 2009				
Energy commodity derivative contracts(a)	\$ 78.1	\$ -	\$ 14.4	\$ 63.7
Interest rate swap agreements	\$ 222.5	\$ -	\$ 222.5	\$ -

	Liability fair value measurements using			
	Total	Quoted prices in active markets for identical liabilities (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
As of March 31, 2010				
Energy commodity derivative contracts(b)	\$ (469.5)	\$ -	\$ (433.3)	\$ (36.2)
Interest rate swap agreements	\$ (174.0)	\$ -	\$ (174.0)	\$ -
As of December 31, 2009				
Energy commodity derivative contracts(b)	\$ (513.5)	\$ -	\$ (462.8)	\$ (50.7)
Interest rate swap agreements	\$ (218.6)	\$ -	\$ (218.6)	\$ -

- (a) Level 2 consists primarily of OTC West Texas Intermediate hedges and OTC natural gas hedges that are settled on NYMEX. Level 3 consists primarily of natural gas basis swaps, natural gas options, and West Texas Intermediate options.
- (b) Level 2 consists primarily of OTC West Texas Intermediate hedges and OTC natural gas hedges that are settled on NYMEX. Level 3 consists primarily of West Texas Sour hedges, natural gas basis swaps, natural gas options, and West Texas Intermediate options.

The fair value measurements in the table above do not include cash margin deposits, which would be reported separately as “Restricted deposits” or included within “Accrued other liabilities” in our accompanying consolidated balance sheets. The table below provides a summary of changes in the fair value of our Level 3 energy commodity derivative contracts for each of the three months ended March 31, 2010 and 2009 (in millions):

Significant unobservable inputs (Level 3)

	Three Months Ended	
	March 31,	
	2010	2009
Derivatives-net asset (liability)		
Beginning of Period.....	\$ 13.0	\$ 44.1
Realized and unrealized net losses.....	8.6	6.3
Purchases and settlements.....	1.0	3.0
Transfers in (out) of Level 3.....	-	-
End of Period.....	<u>\$ 22.6</u>	<u>\$ 53.4</u>
Change in unrealized net losses relating to contracts still held at end of period.....	<u>\$ 3.8</u>	<u>\$ (9.8)</u>

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 March 31, 2010 and December 31, 2009 (both short-term and long-term, but excluding the value of interest rate swaps), is disclosed below (in millions):

	March 31, 2010		December 31, 2009	
	Carrying value	Estimated fair value	Carrying value	Estimated fair value
Total Debt.....	\$ 11,016.4	\$ 11,745.8	\$ 10,592.4	\$ 11,265.7

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;
- CO₂—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 segments' 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. Each segment is managed separately because each segment involves different products and marketing strategies.

Financial information by segment follows (in millions):

	Three Months Ended	
	March 31,	
	2010	2009
Revenues		
Products Pipelines		
Revenues from external customers	\$ 207.5	\$ 188.2
Natural Gas Pipelines		
Revenues from external customers	1,236.7	1,051.7
CO ₂		
Revenues from external customers	321.8	228.9
Terminals		
Revenues from external customers	303.8	267.7
Intersegment revenues	0.3	0.2
Kinder Morgan Canada		
Revenues from external customers	59.8	50.0
Total segment revenues	2,129.9	1,786.7
Less: Total intersegment revenues	(0.3)	(0.2)
Total consolidated revenues	<u>\$ 2,129.6</u>	<u>\$ 1,786.5</u>

	Three Months Ended	
	March 31,	
	2010	2009
Segment earnings before depreciation, depletion, amortization and amortization of excess cost of equity investments(a)		
Products Pipelines(b)	\$ 6.4	\$ 145.4
Natural Gas Pipelines	220.6	200.8
CO ₂	253.2	167.4
Terminals	150.5	134.7
Kinder Morgan Canada	45.0	19.5
Total segment earnings before DD&A	675.7	667.8
Total segment depreciation, depletion and amortization	(227.3)	(210.2)
Total segment amortization of excess cost of investments	(1.4)	(1.4)
General and administrative expenses	(101.1)	(82.5)
Unallocable interest expense, net of interest income	(116.3)	(104.6)
Unallocable income tax expense	(2.2)	(2.3)
Total consolidated net income	<u>\$ 227.4</u>	<u>\$ 266.8</u>

	March 31,	December 31,
	2010	2009
Assets		
Products Pipelines	\$ 4,324.2	\$ 4,299.0
Natural Gas Pipelines	7,840.1	7,772.7
CO ₂	2,207.6	2,224.5
Terminals	3,966.4	3,636.6
Kinder Morgan Canada	1,845.5	1,797.7
Total segment assets	20,183.8	19,730.5
Corporate assets(c)	469.7	531.7
Total consolidated assets	<u>\$ 20,653.5</u>	<u>\$ 20,262.2</u>

- (a) Includes revenues, earnings from equity investments, allocable interest income, and other, net, less operating expenses, allocable income taxes, and other expense (income).
- (b) 2010 amount includes a \$158.0 million increase in expense associated with rate case liability adjustments.
- (c) 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 long-term note receivable bearing interest at the rate of 4.72% per annum from Plantation Pipe Line Company, our 51.17%-owned equity investee. The note provides for semiannual payments of principal and interest on June 30 and December 31 each year, with a final principal payment due July 20, 2011. The outstanding note receivable balance was \$84.8 million as of March 31, 2010 and December 31, 2009. Of these amounts, \$2.6 million was included within "Accounts, notes and interest receivable, net," on our accompanying consolidated balance sheets as of March 31, 2010 and December 31, 2009, and the remainder was included within "Notes receivable" at each reporting date.

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 March 31, 2010 and December 31, 2009, the outstanding note receivable balance, representing the translated amount included in our consolidated financial statements in U.S. dollars, was \$111.8 million and \$108.1 million, respectively, and we included these amounts within "Notes receivable" on our accompanying consolidated balance sheets.

Other Receivables and Payables

As of March 31, 2010 and December 31, 2009, our related party receivables (other than note receivables discussed above in "—Notes Receivable") totaled \$12.3 million and \$13.8 million, respectively. The March 31, 2010 amount consisted of (i) \$10.0 million included within "Accounts, notes and interest receivable, net" and primarily related to receivables due from Plantation Pipe Line Company and from the Express pipeline system; and (ii) \$2.3 million of natural gas imbalance receivables, included within "Other current assets." Our related party imbalance receivables are primarily 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, 2009 amount consisted of (i) \$10.7 million included within "Accounts, notes and interest receivable, net" and primarily related to receivables due from the Express pipeline system and NGPL; and (ii) \$3.1 million of natural gas imbalance receivables, primarily due from NGPL and included within "Other current assets."

As of March 31, 2010 and December 31, 2009, our related party payables totaled \$5.8 million and \$13.4 million, respectively. Both liabilities primarily consisted of amounts owed to KMI, and we included these related party payable amounts within "Accounts payable" on our accompanying balance sheets.

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.

Derivative Counterparties

As a result of KMI's going-private transaction, 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 that term is defined in authoritative accounting literature) to us as of March 31, 2010. 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 (discussed in Note 2).

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 March 31, 2010 and December 31, 2009 (in millions):

	<u>March 31,</u> <u>2010</u>	<u>December 31,</u> <u>2009</u>
Derivatives – asset/(liability)		
Current assets	\$ 1.5	\$ 4.3
Noncurrent assets	\$ 17.4	\$ 18.4
Current liabilities.....	\$ (120.8)	\$ (96.8)
Noncurrent liabilities.....	\$ (150.9)	\$ (190.8)

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, through its wholly owned and controlled subsidiary Kinder Morgan (Delaware), Inc., 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 themselves.

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 2009 Form 10-K.

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 three months ended March 31, 2010. Additional information with respect to these proceedings can be found in Note 16 to our consolidated financial statements that were included in our 2009 Form 10-K. This note also contains a description of any material legal proceedings that were initiated against us during the three months ended March 31, 2010, and a description of any material events occurring subsequent to March 31, 2010 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; Navajo Refining Company, L.P. as Navajo; ARCO Products Company as ARCO; BP West Coast Products, LLC as BP; ConocoPhillips Company as ConocoPhillips; Tesoro Refining and Marketing Company as Tesoro; Texaco Refining and Marketing Inc. as Texaco; Western Refining Company, L.P. as Western Refining; ExxonMobil Oil Corporation as ExxonMobil; Tosco Corporation as Tosco; Ultramar Diamond Shamrock Corporation/Ultramar Inc. as Ultramar; 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 CO₂ Company, L.P. (the successor to Shell CO₂ Company, Ltd.) as Kinder Morgan CO₂; 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 United States Department of the Interior, Minerals Management Service as the MMS; the Union Pacific Railroad Company (the successor to Southern Pacific Transportation Company) as UPRR; the Texas Commission of Environmental Quality as the TCEQ; the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration as the PHMSA; the North Carolina Department of Environment and Natural Resources as the NCDENR; the Florida Department of Environmental Protection as the Florida DEP; our subsidiary Kinder Morgan Bulk Terminals, Inc. as KMBT; our subsidiary Kinder Morgan Port Manatee Terminal LLC as KM PMT; 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

- FERC Docket Nos. OR92-8, *et al.* (West and East Line Rates)—Complainants: Chevron, Navajo, ARCO, BP, Western Refining, ExxonMobil, Tosco, and Texaco—Defendant: SFPP—Status: Appeals pending at the D.C. Circuit;
- FERC Docket No. OR92-8-025 (Watson Drain-Dry Charge)—Complainants: BP; ExxonMobil; Chevron; ConocoPhillips; and Ultramar—Defendant: SFPP—Status: Appeal denied by the D.C. Circuit;
- FERC Docket Nos. OR96-2, *et al.* (All SFPP Rates)—Complainants: All shippers except Chevron—Defendant: SFPP—Status: Compliance filings pending with FERC;
- FERC Docket No. OR02-4 (All SFPP Rates)—Complainant: Chevron—Defendant: SFPP—Status: Appeal of complaint dismissal pending at the D.C. Circuit;
- FERC Docket Nos. OR03-5, OR04-3, OR05-4 & OR05-5 (West, East, North, and Oregon Line Rates)—Complainants: BP, ExxonMobil, ConocoPhillips, the Airlines—Defendant: SFPP—Status: Exceptions to initial decision pending at FERC;
- FERC Docket Nos. OR07-1 & OR07-2 (North and West Line Rates)—Complainant: Tesoro—Defendant: SFPP—Status: Held in abeyance;
- FERC Docket Nos. OR07-3 & OR07-6 (not consolidated) (2005-2006 Index Rate Increases)—Complainants: BP, Chevron, ConocoPhillips, ExxonMobil, Tesoro, and Valero Marketing—Defendant: SFPP—Status: Appeal of dismissal by FERC pending at the D.C. Circuit;
- FERC Docket No. OR07-4 (All SFPP Rates)—Complainants: BP, Chevron, and ExxonMobil—Defendant: SFPP—Status: Held in abeyance;

- FERC Docket Nos. OR07-7, OR07-18, OR07-19 & OR07-22 (not consolidated) (Calnev Rates)—Complainants : Tesoro, Airlines, BP, Chevron, ConocoPhillips and Valero Marketing—Defendant: Calnev—Status: Complaint amendments pending before FERC;
- FERC Docket No. OR07-20 (2007 Index Rate Increases)—Complainant: BP—Defendant: SFPP—Status: Appeal of dismissal by FERC pending at the D.C. Circuit;
- FERC Docket No. OR08-13 (Most SFPP Rates)—Complainants: BP and ExxonMobil—Defendant: SFPP—Status: Held in abeyance;
- FERC Docket No. IS05-230 (North Line Rates)—Protestants: shippers—Defendant: SFPP—Status: Exceptions to initial decision pending at FERC;
- FERC Docket No. IS08-390 (West Line Rates)—Protestants: BP, ExxonMobil, ConocoPhillips, Valero Marketing, Chevron, the Airlines—Defendant: SFPP—Status: Exceptions to initial decision pending at FERC;
- FERC Docket No. IS09-375 (2009 Index Rate Increases)—Protestants: BP, ExxonMobil, Chevron, Tesoro, ConocoPhillips, Western, Navajo, Valero Marketing, and Southwest—Defendant: SFPP—Status: Requests for rehearing of FERC dismissal pending before FERC;
- FERC Docket No. IS09-377 (2009 Index Rate Increases)—Protestants: BP, Chevron, and Tesoro—Defendant: Calnev—Status: Requests for rehearing of FERC dismissal pending before FERC;
- FERC Docket No. IS09-437 (East Line Rates)—Protestants: BP, ExxonMobil, ConocoPhillips, Valero, Chevron, Western Refining, and Southwest Airlines—Defendant: SFPP—Status: Pre-hearing stage;
- FERC Docket Nos. OR08-15/OR09-8 (consolidated) (2008 Index Increases)—Complainants: BP/Chevron—Defendant: SFPP—Status: Complaints partially dismissed and remainder set for hearing; hearing held in abeyance pending settlement discussions;
- FERC Docket Nos. OR09-18/OR09-21 (not consolidated) (2008 and 2009 Index Increases)—Complainants: BP (for 2009)/Tesoro (for 2008 and 2009)—Defendant: SFPP—Status: BP appeal of FERC dismissal pending at the D.C. Circuit;
- FERC Docket Nos. OR09-11/OR09-14 (not consolidated) (2007 and 2008 Page 700 Audit Request)—Complainants: BP/Tesoro—Defendant: Calnev—Status: BP appeal of FERC dismissal pending at the D.C. Circuit;
- FERC Docket Nos. OR09-12/OR09-16 (not consolidated) (2007 and 2008 Page 700 Audit Request)—Complainants: BP/Tesoro—Defendant: SFPP—Status: BP appeal of FERC dismissal pending at the D.C. Circuit;
- FERC Docket Nos. OR09-15/OR09-20 (not consolidated) (Calnev Rates)—Complainants: Tesoro/BP—Defendant: Calnev—Status: Complaints pending at FERC;
- FERC Docket Nos. OR09-17/OR09-22 (Most SFPP Rates) (not consolidated)—Complainants: Tesoro/BP—Defendant: SFPP—Status: BP appeal of FERC dismissal pending at the D.C. Circuit; and
- FERC Docket Nos. OR09-19/OR09-23 (not consolidated) (2009 Index Increases)—Complainants: Tesoro/BP—Defendant: Calnev—Status: BP appeal of FERC dismissal pending at the D.C. Circuit.

The tariffs and rates charged by SFPP and Calnev are subject to numerous ongoing proceedings at the FERC, including the above listed shippers' complaints and protests regarding interstate rates on these pipeline systems. These complaints have been filed over numerous years beginning in 1992 through and including 2009. In general, these complaints 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 complaint) or refunds of any excess rates paid, and SFPP and Calnev may be required to reduce their rates going forward. These proceedings tend to be protracted, with decisions of the FERC often appealed to the federal courts.

As to SFPP, 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. The issues involving Calnev are similar.

During 2009, SFPP made settlement payments to various shippers totaling approximately \$15.5 million in connection with OR07-8, OR07-11, and IS08-28 and related dockets. The IS08-28 settlement (East Line rates) was approved by the FERC in March 2009, and SFPP implemented reduced settlement rates effective May 1, 2009, along with refunds and settlement payments. Due to reduced East Line volumes, SFPP terminated the IS08-28 settlement pursuant to its terms and filed for increased East Line rates (IS09-437), which were accepted and became effective January 1, 2010, subject to refund and investigation.

On April 16, 2010, we filed for approval with the FERC a settlement agreement that we reached with eleven of twelve shippers regarding various rate challenges previously filed with the FERC dating back to 1992. With respect to the eleven shippers, thirty-one dockets will be resolved upon approval of the settlement agreement, and the FERC's approval of the agreement is expected by the third quarter of 2010. The agreement resolves all but two of the cases outstanding between SFPP and the eleven shippers, and we do not expect any material adverse impacts from the remaining two unsettled cases with the eleven shippers. Following the FERC's approval of the agreement, we anticipate paying a total of approximately \$205 million to the eleven shippers. The eleven shippers in the settlement are: Valero; ConocoPhillips; BP; ExxonMobil; Western Refining; Navajo; Tesoro; and the Airlines (four collectively). Chevron is the only shipper who is not a party to the settlement agreement. Chevron's dockets remain open and pending before the FERC.

The settlement resulted in a charge to earnings in the first quarter of 2010; however, due to the support of our general partner, we still expect to distribute \$4.40 in distributions per unit to our limited partners for 2010. As a result of the payment called for under the settlement, we expect that a portion of our distributions for either the second or third quarter of 2010 will be a distribution of cash from Interim Capital Transactions (ICT Distribution) rather than a distribution of cash from operations. As provided in our partnership agreement, our general partner receives no incentive distribution on ICT Distributions. Therefore, there will be no practical impact to our limited partners from this ICT Distribution because (i) the expected cash distribution to the limited partners will not change; (ii) fewer dollars in the aggregate will be distributed, because there will be no incentive distribution paid to the general partner related to the portion of the quarterly distribution that is an ICT Distribution; and (iii) our general partner, in this instance, has agreed to waive any resetting of the incentive distribution target levels, as would otherwise occur according to our partnership agreement. Our general partner will forgo approximately \$100 million of incentive distributions in conjunction with the settlement with the eleven shippers. Also, in the event subsequent payment or payments to Chevron are required, we expect to have sufficient cumulative cash from operations generated in excess of distributions so that distributions to our limited partners will not be affected.

California Public Utilities Commission Proceedings

SFPP has previously reported ratemaking and complaint proceedings 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 that are contrary both to CPUC policy and precedent and to established federal regulatory policies for pipelines. Moreover, contrary to California law, the proposed decision orders refunds relating to these issues where the underlying rates were previously deemed reasonable by the CPUC. Based on our review of these CPUC proceedings, we estimate that our maximum exposure is approximately \$220 million in reparation and refund payments and if the determinations made in the proposed decision were applied prospectively in two pending cases this could result in approximately \$30 million in annual rate reductions.

The proposed decision is advisory in nature and can be rejected, accepted or modified by the CPUC. SFPP will file comments on May 3 outlining the errors in law and fact within the proposed decision and is scheduled to make oral argument before the full CPUC on May 5, 2010. Further procedural steps, including motions for rehearing and writ of review to California's Court of Appeals, will be taken if warranted. We do not expect the final resolution of this matter to have an impact on our expected distributions to our limited partners for 2010.

Carbon Dioxide Litigation

Gerald O. Bailey et al. v. Shell Oil Co. et al., Southern District of Texas Lawsuit

Kinder Morgan CO₂, Kinder Morgan Energy Partners, L.P. and Cortez Pipeline Company are among the defendants in a proceeding in the federal courts for the Southern District of Texas. *Gerald O. Bailey et al. v. Shell Oil Company et al.* (Civil Action Nos. 05-1029 and 05-1829 in the U.S. District Court for the Southern District of Texas—consolidated by Order dated July 18, 2005). The plaintiffs assert claims for the underpayment of royalties on carbon dioxide produced from the McElmo Dome unit, located in southwestern Colorado. The plaintiffs assert claims for fraud/fraudulent inducement, real estate fraud, negligent misrepresentation, breach of fiduciary and agency duties, breach of contract and covenants, violation of the Colorado Unfair Practices Act, civil theft under Colorado law, conspiracy, unjust enrichment, and open account. Plaintiffs Gerald O. Bailey, Harry Ptasynski, and W.L. Gray & Co. also assert claims as private relators under the False Claims Act, claims on behalf of the State of Colorado and Montezuma County, Colorado, and claims for violation of federal and Colorado antitrust laws. The plaintiffs seek actual damages, treble damages, punitive damages, a constructive trust and accounting, and declaratory relief. The defendants filed motions for summary judgment on all claims.

On April 22, 2008, the federal district court granted defendants' motions for summary judgment and ruled that plaintiffs Bailey and Ptasynski take nothing on their claims, and that the claims of Gray be dismissed with prejudice. The court entered final judgment in favor of the defendants on April 30, 2008. Defendants filed a motion seeking sanctions against plaintiffs Bailey and Ptasynski and their attorney. The plaintiffs appealed the final judgment to the United States Fifth Circuit Court of Appeals. The parties concluded their briefing to the Fifth Circuit Court of Appeals in February 2009, and the appeal remains pending.

CO₂ Claims Arbitration

Kinder Morgan CO₂ and Cortez Pipeline Company were among the named defendants in *CO₂ 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 (*CO₂ Committee, Inc. v. Shell CO₂ Company, Ltd., aka Kinder Morgan CO₂ Company, L.P., et al.*) against Cortez Pipeline Company, Kinder Morgan CO₂ and an ExxonMobil entity. The second arbitration asserts claims similar to those asserted in the first arbitration. On June 3, 2008, the plaintiffs filed a request with the American Arbitration Association seeking administration of the arbitration. In October 2008, the New Mexico federal district court entered an order declaring that the panel in the first arbitration should decide whether the claims in the second arbitration are barred by res judicata (an adjudicated issue that cannot be relitigated). The plaintiffs filed a motion for reconsideration of that order, which was denied by the New Mexico federal district court in January 2009. Plaintiffs appealed to the Tenth Circuit Court of Appeals. On December 21, 2009, the Tenth Circuit Court of Appeals reversed the District Court and ruled that a new arbitration panel should be convened to decide the claims and defenses asserted by the parties.

MMS Notice of Noncompliance and Civil Penalty

On December 20, 2006, Kinder Morgan CO₂ received from the MMS a “Notice of Noncompliance and Civil Penalty: Knowing or Willful Submission of False, Inaccurate, or Misleading Information—Kinder Morgan CO₂ Company, L.P., case no. CP07-001.” This Notice, and the MMS’s position that Kinder Morgan CO₂ has violated certain reporting obligations, relates to a disagreement between the MMS and Kinder Morgan CO₂ concerning the approved transportation allowance to be used in valuing McElmo Dome carbon dioxide for purposes of calculating federal royalties.

The Notice of Noncompliance and Civil Penalty assesses a civil penalty of approximately \$2.2 million as of December 15, 2006 (based on a penalty of \$500.00 per day for each of 17 alleged violations) for Kinder Morgan CO₂’s alleged submission of false, inaccurate, or misleading information relating to the transportation allowance, and federal royalties for CO₂ produced at McElmo Dome, during the period from June 2005 through October 2006. The MMS stated that civil penalties will continue to accrue at the same rate until the alleged violations are corrected.

On January 3, 2007, Kinder Morgan CO₂ appealed the Notice of Noncompliance and Civil Penalty to the Office of Hearings and Appeals of the Department of the Interior. In February 2007, Kinder Morgan CO₂ filed a motion seeking to stay the accrual of civil penalties during the appeal, which was denied.

In July 2008, the parties reached a settlement of the Notice of Noncompliance and Civil Penalty, subject to final approval by the MMS and the Department of the Interior. On January 28, 2010, a representative of the MMS notified Kinder Morgan CO₂ that the Department of the Interior will not approve the settlement on its existing terms. The parties are engaged in renewed settlement discussions.

MMS Orders to Report and Pay

On March 20, 2007, Kinder Morgan CO₂ received an “Order to Report and Pay” from the MMS. The MMS contends that Kinder Morgan CO₂ has over-reported transportation allowances and underpaid royalties in the amount of approximately \$4.6 million for the period from January 1, 2005 through December 31, 2006 as a result of its use of the Cortez Pipeline tariff as the transportation allowance in calculating federal royalties. The MMS claims that the Cortez Pipeline tariff is not the proper transportation allowance and that Kinder Morgan CO₂ must use its “reasonable actual costs” calculated in accordance with certain federal product valuation regulations. The MMS set a due date of April 13, 2007 for Kinder Morgan CO₂’s payment of the \$4.6 million in claimed additional royalties, with possible late payment charges and civil penalties for failure to pay the assessed amount.

Kinder Morgan CO₂ has not paid the \$4.6 million, and on April 19, 2007, it submitted a notice of appeal and statement of reasons in response to the Order to Report and Pay, challenging the Order and appealing it to the Director of the MMS in accordance with 30 C.F.R. sec. 290.100, et seq.

In addition to the March 2007 Order to Report and Pay, the MMS issued a second Order to Report and Pay in August 2007, in which the MMS claims that Kinder Morgan CO₂ has over-reported transportation allowances and underpaid royalties (due to the use of the Cortez Pipeline tariff as the transportation allowance for purposes of federal royalties) in the amount of approximately \$8.5 million for the period from April 2000 through December 2004. Kinder Morgan CO₂ filed its notice of appeal and statement of reasons in response to the second Order in September 2007, challenging the Order and appealing it to the Director of the MMS.

In July 2008, the parties reached a settlement of the March 2007 and August 2007 Orders to Report and Pay, subject to final approval by the MMS and the Department of the Interior. On January 28, 2010, a representative of the MMS notified Kinder Morgan CO₂ that the Department of the Interior will not approve the settlement on its existing terms. The parties are engaged in renewed settlement discussions.

Colorado Severance Tax Assessment

On September 16, 2009, the Colorado Department of Revenue issued three Notices of Deficiency to Kinder Morgan CO₂. The Notices of Deficiency assessed additional state severance tax against Kinder Morgan CO₂ 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 CO₂ protested the

Notices of Deficiency and paid the tax and interest under protest. Kinder Morgan CO₂ 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 CO₂, 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 CO₂'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 CO₂ 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 CO₂'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 vs. 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 is ongoing and is expected to conclude by the end of the second quarter of 2010, with a decision from the judge expected by the end of 2010.

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 and results of operations. 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.

JR Nicholls Tug Incident

On February 10, 2010, the *JR Nicholls*, a tugboat operated by one of our subsidiaries, overturned and sank in the Houston Ship Channel. Five employees were on board and four were rescued, treated and released from a local hospital. The fifth employee died in the incident. The U.S. Coast Guard shut down a section of the ship channel for approximately 60 hours. Approximately 2,200 gallons of diesel fuel was released from the tugboat. Emergency response crews deployed booms and contained the product, which is substantially cleaned up. Salvage operations were commenced and the tugboat has been recovered. A full investigation of the incident is underway.

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. Defendants intend to vigorously defend the case.

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.

Midcontinent Express Pipeline LLC Construction Incident

On July 15, 2009, a Midcontinent Express Pipeline LLC contractor and subcontractor were conducting a nitrogen pressure test on-facilities at a Midcontinent Express Pipeline delivery meter station that was under construction-in Smith County, Mississippi. An unexpected release of nitrogen occurred during testing, resulting in one fatality and injuries to four other employees of the contractor or subcontractor. The United States Occupational Safety and Health Administration (OSHA) completed its investigation. Neither Midcontinent Express Pipeline LLC nor we were cited for any violations by OSHA.

Pasadena Terminal Fire

On September 23, 2008, a fire occurred in the pit 3 manifold area of our Pasadena, Texas liquids terminal facility. One of our employees was injured and subsequently died. In addition, the pit 3 manifold was severely damaged. On July 13, 2009, a civil lawsuit was filed by and on behalf of the family of the deceased employee entitled *Brandy Williams et al. v. KMGP Services Company, Inc.* in the 133rd District Court of Harris County, Texas, case no. 2009-44321. On December 28, 2009, the case was settled via an Agreed Judgment entered by the court, and the matter is now concluded.

Additionally, on January 8, 2010, a civil lawsuit was filed on behalf of the People of Texas and the TCEQ for alleged violations of the Texas Clean Air Act. The lawsuit was filed in the 53rd Judicial District Court, Travis County, Texas and is entitled *State of Texas v. Kinder Morgan Liquids Terminals*, case no. D1GV10000017. Specifically, the TCEQ alleges that our subsidiary, Kinder Morgan Liquids Terminals LLC, had an unauthorized emission event relating to the pit 3 fire at the Pasadena terminal. We are currently in discussions with the TCEQ legal representatives and the Texas Attorney General's office regarding resolution of this matter. We do not expect any fines or penalties related to this matter to be material.

Rockies Express Pipeline LLC Wyoming Construction Incident

On November 11, 2006, a bulldozer operated by an employee of Associated Pipeline Contractors, Inc., a third-party contractor to Rockies Express, struck an existing subsurface natural gas pipeline owned by Wyoming Interstate Company, a subsidiary of El Paso Pipeline Group. The pipeline was ruptured, resulting in an explosion and fire. The incident occurred in

a rural area approximately nine miles southwest of Cheyenne, Wyoming. The incident resulted in one fatality (the operator of the bulldozer), and there were no other reported injuries. The cause of the incident was investigated by the PHMSA. In March 2008, the PHMSA issued a Notice of Probable Violation, Proposed Civil Penalty and Proposed Compliance Order, or NOPV, to El Paso Corporation in which it concluded that El Paso failed to comply with federal law and its internal policies and procedures regarding protection of its pipeline, resulting in this incident. The PHMSA issued a Final Order to El Paso on November 23, 2009.

The PHMSA has not issued any NOPV's to Rockies Express, and we do not expect that it will do so. Immediately following the incident, Rockies Express and El Paso Pipeline Group reached an agreement on a set of additional enhanced safety protocols designed to prevent the reoccurrence of such an incident.

In September 2007, the family of the deceased bulldozer operator filed a wrongful death action against us, Rockies Express and several other parties in the District Court of Harris County, Texas, 189th Judicial District, case number 2007-57916. The plaintiffs seek unspecified compensatory and exemplary damages plus interest, attorney's fees and costs of suit. We have asserted 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. On March 25, 2008, we entered into a settlement agreement with one of the plaintiffs, the decedent's daughter, resolving any and all of her claims against us, Rockies Express and its contractors. In January 2010, we entered into a settlement agreement with each of the remaining plaintiffs, effectively concluding this matter. We were indemnified for the full amount of both settlements by one of Rockies Express' contractors.

Charlotte, North Carolina

On January 17, 2010, our subsidiary Kinder Morgan Southeast Terminal LLC's Charlotte #2 Terminal experienced an issue with a pollution control device known as the Vapor Recovery Unit, which led to a fire and release of gasoline from the facility to adjacent property and a small creek. There were no injuries. We are cooperating fully with state and federal agencies on the response and remediation.

Barstow, California

The United States Department of the Navy has alleged that historic releases of methyl tertiary-butyl ether, or MTBE, from Calnev Pipe Line Company'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 Terminal, 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 (U.S.). Cleanup and environmental remediation is complete, and we have received a British Columbia Ministry of Environment Certificate of Compliance confirming complete remediation.

The National Transportation Safety Board released its investigation report on the incident on March 18, 2009. The report confirmed that an absence of pipeline location marking in advance of excavation and inadequate communication between the contractor and our subsidiary Kinder Morgan Canada Inc., the operator of the line, were the primary causes of the accident. No directives, penalties or actions of Kinder Morgan Canada Inc. were required as a result of the report.

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. We are of the view that the charges have been improperly laid against us, and we intend to vigorously defend against them.

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 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 March 31, 2010 and December 31, 2009, we have recorded a total reserve for legal fees, transportation rate cases and other litigation liabilities in the amount of \$372.6 million and \$220.9 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 year-end 2009 includes a \$158.0 million increase in expense associated with rate case liability adjustments in the first quarter of 2010 that increased expense. We regularly assess the likelihood of adverse outcomes resulting from these claims in order to determine the adequacy of our liability provision.

Environmental Matters

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.

Our subsidiary, Kinder Morgan Liquids Terminals LLC, 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 remains stayed through the first half of 2010. The court may lift the stay in the second half of 2010. During the stay, the parties deemed responsible by the local regulatory agency have worked with that agency concerning the scope of the required cleanup. The local regulatory agency issued specific cleanup goals in early 2010, and two of those parties, including Kinder Morgan Liquids Terminals, LLC, have appealed those cleanup goals to the state agency.

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, later owned by Support Terminals. The terminal is now owned by Pacific Atlantic Terminals, LLC, 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 our subsidiary Kinder Morgan Liquids Terminals LLC, formerly known as GATX Terminals Corporation. The complaint was filed in Gloucester County, New Jersey. Both ExxonMobil and Kinder Morgan Liquids Terminals LLC filed third party complaints against Support Terminals seeking to bring Support Terminals into the case. Support Terminals filed motions to dismiss the third party complaints, which were denied. Support Terminals is now joined in the case, and it filed an Answer denying all claims. The court has consolidated the two cases.

The plaintiffs seek the costs and damages that the plaintiffs allegedly have incurred or will incur as a result of the discharge of pollutants and hazardous substances at the Paulsboro, New Jersey facility. The costs and damages that the plaintiffs seek include cleanup costs and damages to natural resources. In addition, the plaintiffs seek an order compelling the defendants to perform or fund the assessment and restoration of those natural resource damages that are the result of the defendants' actions. At the time of this report, the plaintiffs have filed a report asserting that the cost of natural resource restoration is \$81 million. Defendants vigorously dispute that estimate. In addition, we believe that any damages, including restoration damages, would be the responsibility of the other co-defendants under applicable law and indemnity agreements between the parties.

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. Discovery has commenced and the court has set a trial date of January 24, 2012. 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. On January 19, 2010, the City filed a notice of intent to file an additional claim under the Resource Conservation and Recovery Act. 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.

Kinder Morgan Port Manatee Terminal, Palmetto, Florida

On June 18, 2009, KM PMT received a Revised Warning Letter from the Florida DEP, advising us of possible regulatory and air permit violations regarding operations at our Port Manatee, Florida terminal. We previously conducted a voluntary internal audit at this facility in March 2008 and identified various environmental compliance and permitting issues primarily related to air quality compliance. We self-reported our findings from this audit in a self-disclosure letter to the Florida DEP in March 2008. Following the submittal of our self-disclosure letter, the agency conducted numerous inspections of the air pollution control devices at the terminal and issued this Revised Warning Letter. In addition, KM PMT received a subpoena from the U.S. Department of Justice for production of documents related to the service and operation of the air pollution control devices at the terminal.

In February 2010, KM PMT entered into a plea agreement with the U.S. Attorney's office for the Middle District of Florida to resolve the air permit violations at our Port Manatee terminal that occurred between 2001 and 2008. During this period of time, former local terminal management failed to disclose and address the operational condition of control equipment at the facility, as required by the Clean Air Act. To resolve the matter, KM PMT has entered into a plea agreement concerning criminal violations of the Clean Air Act and has agreed to pay a fine of \$750,000 and a community service payment of \$250,000 to the National Fish & Wildlife Foundation. In addition, in order to resolve the matter with the Florida DEP, KM PMT has entered into a civil Consent Order with the Florida DEP under which it has agreed to implement an Environmental Compliance Plan and to pay \$336,000 in civil penalties and costs. We have fully cooperated with the government's investigation, and have taken appropriate measures at the terminal, including replacing and repairing control equipment, adding new equipment, terminating certain employees, and retraining current employees on proper environmental procedures.

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.

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. 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.

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 March 31, 2010, we have accrued an environmental reserve of \$79.6 million, and we believe the establishment of this environmental reserve is adequate such that the resolution of 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 March 31, 2010, we have recorded a receivable of \$8.6 million for expected cost recoveries that have been deemed probable. As of December 31, 2009, our environmental reserve totaled \$81.1 million and our estimated receivable for environmental cost recoveries totaled \$4.3 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

Below is a brief description of our ongoing regulatory matters, including any material developments that occurred during the first three months of 2010. This note also contains a description of any material regulatory matters initiated during the first three months of 2010 in which we are involved.

Natural Gas Pipeline Expansion Filings

Rockies Express Pipeline LLC Meeker to Cheyenne Expansion Project

Pursuant to certain rights exercised by EnCana Gas Marketing USA as a result of its foundation shipper status on the former Entrega Gas Pipeline LLC facilities (now part of the Rockies Express Pipeline), Rockies Express Pipeline LLC requested authorization to construct and operate certain facilities that will comprise its Meeker, Colorado to Cheyenne Hub expansion project. The proposed expansion will add natural gas compression at its Big Hole compressor station located in Moffat County, Colorado, and its Arlington compressor station located in Carbon County, Wyoming. Upon completion, the additional compression will permit the transportation of an additional 200 million cubic feet per day of natural gas from (i) the Meeker Hub located in Rio Blanco County, Colorado northward to the Wamsutter Hub located in Sweetwater County, Wyoming; and (ii) the Wamsutter Hub eastward to the Cheyenne Hub located in Weld County, Colorado.

By FERC order issued July 16, 2009, Rockies Express Pipeline LLC was granted authorization to construct and operate this project, and it commenced construction on August 4, 2009. The expansion is fully contracted. The additional compression at the Big Hole compressor station was made available as of December 9, 2009, and the additional compression at the Arlington compressor station is expected to be operational in August 2010. The total FERC authorized cost for the proposed project is approximately \$78 million; however, Rockies Express Pipeline LLC is currently projecting that the final actual cost will be approximately \$25 million less.

Kinder Morgan Interstate Gas Transmission Pipeline - Huntsman 2009 Expansion Project

KMIGT has filed an application with the FERC for authorization to construct and operate certain storage facilities necessary to increase the storage capability of the existing Huntsman Storage Facility, located near Sidney, Nebraska. KMIGT also requested approval of new incremental rates for the project facilities under its currently effective Cheyenne Market Center Service Rate Schedule CMC-2. When fully constructed, the proposed facilities will create incremental firm storage capacity for up to one million dekatherms of natural gas, with an associated injection capability of approximately 6,400 dekatherms per day and an associated deliverability of approximately 10,400 dekatherms per day. As a result of an open season, KMIGT and one shipper executed a firm precedent agreement for 100% of the capacity to be created by the project facilities for a five-year term. By FERC order issued September 30, 2009, KMIGT was granted authorization to construct and operate the project, and construction of the project commenced on October 12, 2009. KMIGT received FERC approval to commence the expanded storage service effective February 1, 2010.

Kinder Morgan Louisiana Pipeline LLC (KMLP) – Docket No. CP06-449-000

On April 16, 2009, our subsidiary Kinder Morgan Louisiana Pipeline LLC received authorization from the FERC to begin service on Leg 2 of the approximately 133-mile, 42-inch diameter Kinder Morgan Louisiana Pipeline. Natural gas transportation service on Leg 2 commenced April 18, 2009, and on June 21, 2009, Kinder Morgan Louisiana Pipeline LLC completed pipeline construction and placed the remaining portion of the pipeline system into service. The Kinder Morgan Louisiana Pipeline project cost approximately \$1 billion to complete and provides approximately 3.2 billion cubic feet per day of take-away natural gas capacity from the Cheniere Sabine Pass liquefied natural gas terminal, located in Cameron Parish, Louisiana, to various delivery points in Louisiana. The pipeline interconnects with multiple third-party pipelines and all of the capacity on the pipeline system has been fully subscribed by Chevron U.S.A Inc. and Total Gas & Power North America, Inc. under 20-year firm transportation contracts. Total's contract became effective on June 21, 2009, and Chevron's contract became effective on October 1, 2009.

Midcontinent Express Pipeline LLC – Docket Nos. CP08-6-000 and CP09-56-000

On April 10, 2009, Midcontinent Express Pipeline LLC placed Zone 1 of the Midcontinent Express natural gas pipeline system into interim service. Zone 1 extends from Bennington, Oklahoma to the interconnect with Columbia Gulf Transmission Company in Madison Parish, Louisiana. It has a design capacity of approximately 1.5 billion cubic feet per day. On August 1, 2009, construction of the pipeline was completed, and Zone 2 was placed into service. Zone 2 extends from the Columbia Gulf interconnect to the terminus of the system in Choctaw County, Alabama. It has a design capacity of approximately 1.2 billion cubic feet per day. In an order issued September 17, 2009, the FERC approved Midcontinent Express' (i) amendment to move one compressor station in Mississippi and modify the facilities at another station in

Texas (both stations were among the facilities certificated in the July 2008 Order authorizing the system's original construction); and (ii) request to expand the capacity in Zone 1 by 0.3 billion cubic feet per day (this expansion is expected to be completed as early as June 2010).

The Midcontinent Express Pipeline is owned by Midcontinent Express Pipeline LLC, a 50/50 joint venture between us and Energy Transfer Partners, L.P. The pipeline originates near Bennington, Oklahoma and extends from southeast Oklahoma, across northeast Texas, northern Louisiana and central Mississippi, and terminates at an interconnection with the Transco Pipeline near Butler, Alabama. The approximate 500-mile natural gas pipeline system connects the Barnett Shale, Bossier Sands and other natural gas producing regions to markets in the eastern United States, and substantially all of the pipeline's capacity—including all incremental pipeline capacity that is expected to be phased in during the second and third quarters of 2010—is fully subscribed with long-term binding commitments from creditworthy shippers. Including expansions, the current estimated cost of the entire Midcontinent Express pipeline project is approximately \$2.3 billion (consistent with our April 21, 2010 first quarter earnings press release).

Fayetteville Express Pipeline LLC – Docket No. CP09-433-000

Construction is now underway on all phases of the previously announced Fayetteville Express Pipeline project. The Fayetteville Express Pipeline is owned by Fayetteville Express Pipeline LLC, another 50/50 joint venture between us and Energy Transfer Partners, L.P. The Fayetteville Express Pipeline is a 187-mile, 42-inch diameter natural gas pipeline that will begin in Conway County, Arkansas, continue eastward through White County, Arkansas, and will terminate at an interconnection with Trunkline Gas Company's pipeline in Panola County, Mississippi. The pipeline will have an initial capacity of two billion cubic feet per day, and has currently secured binding commitments for at least ten years totaling 1.85 billion cubic feet per day of capacity.

On December 17, 2009, the FERC approved and issued the pipeline's certificate application authorizing pipeline construction, and initial construction on the project began in January 2010. Pending regulatory approvals, the pipeline is expected to begin interim service in the fourth quarter of 2010 and be fully in service by the end of 2010. We estimate that the total costs of this pipeline project will be below \$1.2 billion (consistent with our April 21, 2010 first quarter earnings press release and below the original budget of \$1.3 billion).

12. Recent Accounting Pronouncements

Accounting Standards Updates

In December 2009, the FASB issued Accounting Standards Update No. 2009-16, "Accounting for Transfers of Financial Assets" and Accounting Standards Update No. 2009-17, "Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities." ASU No. 2009-16 amended the Codification's "Transfers and Servicing" Topic to include the provisions included within the FASB's previous Statement of Financial Accounting Standards (SFAS) No. 166, "Accounting for Transfers of Financial Assets—an amendment of FASB Statement No. 140," issued June 12, 2009. ASU No. 2009-17 amended the Codification's "Consolidations" Topic to include the provisions included within the FASB's previous SFAS No. 167, "Amendments to FASB Interpretation No. 46(R)," also issued June 12, 2009. These two Updates change the way entities must account for securitizations and special-purpose entities. ASU No. 2009-16 requires more information about transfers of financial assets, including securitization transactions, and where companies have continuing exposure to the risks related to transferred financial assets. ASU No. 2009-17 changes how a company determines when an entity that is insufficiently capitalized or is not controlled through voting (or similar rights) should be consolidated. For us, both Updates were effective January 1, 2010; however, the adoption of these Updates did not have any impact on our consolidated financial statements.

In January 2010, the FASB issued Accounting Standards Update No. 2010-06, "Improving Disclosures about Fair Value Measurements." This ASU requires both the gross presentation of activity within the Level 3 fair value measurement roll forward and the details of transfers in and out of Level 1 and 2 fair value measurements. It also clarifies certain disclosure requirements on the level of disaggregation of fair value measurements and disclosures on inputs and valuation techniques. For us, this ASU was effective January 1, 2010 (except for the Level 3 roll forward which is effective for us January 1, 2011); however, because this ASU pertains to disclosure requirements only, the adoption of this ASU did 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); and (ii) our consolidated financial statements, related notes and management’s discussion and analysis of financial condition and results of operations included in our 2009 Form 10-K.

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 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.

Further information about us and information regarding our accounting policies and estimates that we consider to be “critical” can be found in our 2009 Form 10-K. There have not been any significant changes in these policies and estimates during the three months ended March 31, 2010. Furthermore, with regard to our goodwill impairment testing, there has been no change during the three months ended March 31, 2010 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.

Results of Operations

Consolidated

	Three Months Ended March 31,		Earnings	
	2010	2009	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)	\$ 6.4	\$ 145.4	\$ (139.0)	(96)%
Natural Gas Pipelines(c)	220.6	200.8	19.8	10 %
CO ₂ (d).....	253.2	167.4	85.8	51 %
Terminals(e).....	150.5	134.7	15.8	12 %
Kinder Morgan Canada(f)	45.0	19.5	25.5	131 %
Segment earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	675.7	667.8	7.9	1 %
Depreciation, depletion and amortization expense.....	(227.3)	(210.2)	(17.1)	(8)%
Amortization of excess cost of equity investments	(1.4)	(1.4)	-	-
General and administrative expense(g)	(101.1)	(82.5)	(18.6)	(23)%
Unallocable interest expense, net of interest income(h).....	(116.3)	(104.6)	(11.7)	(11)%
Unallocable income tax expense	(2.2)	(2.3)	0.1	4 %
Net income.....	227.4	266.8	(39.4)	(15)%
Net income attributable to noncontrolling interests(i).....	(2.1)	(2.9)	0.8	28 %
Net income attributable to Kinder Morgan Energy Partners, L.P.	\$ 225.3	\$ 263.9	\$ (38.6)	(15)%

(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) 2010 amount includes a \$158.0 million expense associated with rate case liability adjustments, and a \$0.5 million increase in income resulting from unrealized foreign currency gains on long-term debt transactions. 2009 amount includes a \$0.6 million decrease in income resulting from unrealized foreign currency losses on long-term debt transactions.
- (c) 2010 amount includes a \$0.9 million unrealized gain 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. 2009 amount includes a \$1.3 million decrease in income resulting from unrealized mark to market gains and losses due to the discontinuance of hedge accounting at Casper Douglas.
- (d) 2010 amount includes a \$5.4 million unrealized gain on derivative contracts used to hedge forecasted crude oil sales.
- (e) 2010 amount includes a \$0.4 million decrease in income related to storm and flood clean-up and repair activities.
- (f) 2009 amount includes a \$14.9 million increase in expense primarily due to certain non-cash regulatory accounting adjustments to the carrying amount of the previously established deferred tax liability.
- (g) Includes unallocated litigation and environmental expenses. 2010 amount includes (i) a \$1.6 million increase in legal expense associated with certain items such as legal settlements and pipeline failures; (ii) a \$1.4 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); (iii) a \$1.4 million increase in expense for certain asset and business acquisition costs; and (iv) a \$0.3 million decrease in expense related to capitalized overhead costs associated with the 2008 hurricane season. 2009 amount includes (i) a \$1.4 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 \$0.1 million increase in expense for certain Express pipeline system acquisition costs; and (iii) a \$0.6 million decrease in expense related to capitalized overhead costs associated with the 2008 hurricane season.
- (h) 2010 and 2009 amounts include increases in imputed interest expense of \$0.4 million and \$0.5 million, respectively, related to our January 1, 2007 Cochin Pipeline acquisition.
- (i) 2010 and 2009 amounts include decreases of \$2.3 million and \$0.2 million, respectively, in net income attributable to our noncontrolling interests, related to the effect from all of the three month 2010 and 2009 items previously disclosed in these footnotes.

For the quarterly period ended March 31, 2010, net income attributable to our partners, which includes all of our limited partner unitholders and our general partner, totaled \$225.3 million. This compares to net income attributable to our partners of \$263.9 million for the first quarter of 2009. Total revenues for the comparable first quarter periods were \$2,129.6 million in 2010 and \$1,786.5 million in 2009.

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.

Including the certain items described in the footnotes to the table above, our total segment earnings before depreciation, depletion and amortization for the three months ended March 31, 2010 increased \$7.9 million (1%) when compared to the same quarter last year. The overall quarter-to-quarter increase in total segment EBDA includes a \$134.4 million decrease from the certain items, which combined to decrease total segment EBDA by \$151.2 million in the first quarter of 2010 and to decrease total segment EBDA by \$16.8 million in the first quarter of 2009. The remaining \$142.3 million (21%) increase in total segment earnings before depreciation, depletion and amortization included higher earnings in 2010 from all five of our business segments, with the strongest growth coming from our CO₂ business segment.

Products Pipelines

	Three Months Ended March 31,	
	2010	2009
	(In millions, except operating statistics)	
Revenues.....	\$ 207.5	\$ 188.2
Operating expenses(a)	(208.9)	(49.0)
Earnings from equity investments.....	5.8	5.4
Interest income and Other, net-income(b)	2.6	2.8
Income tax expense.....	(0.6)	(2.0)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	\$ 6.4	\$ 145.4
Gasoline (MMBbl)(c)	93.8	95.6
Diesel fuel (MMBbl)	32.8	35.5
Jet fuel (MMBbl)	24.8	26.8
Total refined product volumes (MMBbl).....	151.4	157.9
Natural gas liquids (MMBbl).....	5.9	4.8
Total delivery volumes (MMBbl)(d).....	157.3	162.7
Ethanol (MMBbl)(e).....	7.2	5.1

- (a) 2010 amount includes a \$158.0 million expense associated with rate case liability adjustments.
- (b) 2010 and 2009 amounts include a \$0.5 million increase in income and a \$0.6 million decrease in income, respectively, resulting from unrealized foreign currency gains and losses on long-term debt transactions.
- (c) Volumes include ethanol pipeline volumes.
- (d) Includes Pacific, Plantation, Calnev, Central Florida, Cochin and Cypress pipeline volumes.
- (e) Represents total ethanol volumes, including ethanol pipeline volumes.

The certain items related to our Products Pipelines business segment and described in the footnotes to the table above decreased earnings by \$157.5 million in the first quarter of 2010 and by \$0.6 million in the first quarter of 2009 (accounting for a \$156.9 million decrease in earnings before depreciation, depletion and amortization in the first quarter of 2010, when compared to the first quarter a year ago). Following is information related to the increases and decreases in the segment's (i) remaining \$17.9 million (12%) increase in earnings before depreciation, depletion and amortization; and (ii) \$19.3 million (10%) increase in operating revenues:

Three months ended March 31, 2010 versus Three months ended March 31, 2009

	EBDA		Revenues	
	increase/(decrease)		increase/(decrease)	
	(In millions, except percentages)			
Pacific operations.....	\$ 9.7	15 %	\$ 10.7	12 %
Southeast Terminals.....	4.6	40 %	4.8	27 %
Calnev Pipeline	2.4	20 %	1.5	9 %
Central Florida Pipeline	1.2	10 %	1.0	7 %
West Coast Terminals	1.2	7 %	1.1	5 %
Cochin Pipeline.....	(2.6)	(23)%	(0.2)	(2)%
All others (including intrasegment eliminations).....	1.4	8 %	0.4	2 %
Total Products Pipelines.....	\$ 17.9	12 %	\$ 19.3	10 %

Overall, our Products Pipelines business segment reported strong operating results in the first quarter of 2010 as earnings before depreciation, depletion and amortization expenses increased \$17.9 million (12%), when compared to the first quarter of 2009. With the exception of the Cochin pipeline system, which was impacted by certain favorable liability

adjustments recorded in the first quarter of 2009, all of the assets and operations included in our Products Pipelines business segment reported higher earnings in the first quarter of 2010, when compared to the first quarter a year ago. For all assets combined, the segment benefited from a 41% increase in total ethanol volumes handled in the first quarter of 2010, and although the growing use of ethanol as part of the domestic fuel supply tends to reduce other refined products pipeline volumes, we believe the capital investments we have made for ethanol storage and blending infrastructure have enabled us to recover the decreases in revenues and cash flows resulting from lower pipeline transport volumes.

The primary increases and decreases in segment earnings before depreciation, depletion and amortization for the two comparable quarterly periods were attributable to the following:

- a \$9.7 million (15%) increase in earnings from our Pacific operations—driven by a \$10.7 million (12%) increase in operating revenues, consisting of (i) a \$7.6 million (12%) increase in mainline delivery revenues, due to higher average tariff rates which more than offset an overall 3% drop in mainline delivery volumes; and (ii) a \$3.1 million increase in terminal revenues, primarily related to incremental ethanol handling services;
- a \$4.6 million (40%) increase in earnings from our Southeast terminal operations—related largely to a \$4.8 million (27%) increase in revenues that was chiefly attributable to increased ethanol throughput and storage activities;
- a \$2.4 million (20%) increase in earnings from our Calnev Pipeline—driven by a \$1.5 million (9%) increase in revenues, attributable mainly to higher average tariff rates compared to the first quarter last year, and to a \$0.7 million (37%) reduction in combined fuel and power expenses, primarily due to a 2% decrease in total refined products delivery volumes;
- a \$1.2 million (10%) increase in earnings from our Central Florida Pipeline—driven by incremental ethanol revenues and higher refined products delivery revenues;
- a \$1.2 million (7%) increase in earnings from our West Coast terminal operations—driven by incremental biodiesel revenues from our liquids facilities located in Portland, Oregon, and from an incremental contribution from the terminals' Portland, Oregon Airport pipeline, which was acquired on July 31, 2009; and
- a \$2.6 million (23%) decrease in earnings from our Cochin pipeline system—related mainly to a \$1.7 million decrease from higher operating expenses and a \$1.4 million decrease from lower other non-operating income, when compared to the first quarter of 2009. Both decreases were primarily related to favorable settlements reached in the first quarter of 2009 with the seller of the remaining approximate 50.2% interest in the Cochin pipeline system that we purchased on January 1, 2007.

Natural Gas Pipelines

	Three Months Ended	
	March 31,	
	2010	2009
	(In millions, except operating statistics)	
Revenues(a)	\$ 1,236.7	\$ 1,051.7
Operating expenses(b)	(1,051.5)	(890.5)
Earnings from equity investments.....	33.8	26.6
Interest income and Other, net-income	2.2	14.7
Income tax expense.....	(0.6)	(1.7)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	<u>\$ 220.6</u>	<u>\$ 200.8</u>
Natural gas transport volumes (Bcf)(c).....	<u>633.7</u>	<u>508.4</u>
Natural gas sales volumes (Bcf)(d).....	<u>189.0</u>	<u>203.7</u>

(a) 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) 2010 amount includes a \$0.9 million unrealized gain (from a decrease in natural gas purchase costs) on derivative contracts used to hedge forecasted natural gas sales. 2009 amount includes a \$1.3 million decrease in income resulting from unrealized mark to

market gains and losses due to the discontinuance of hedge accounting at Casper Douglas. Beginning in the second quarter of 2008, our Casper and Douglas gas processing operations discontinued hedge accounting, and the last of the related derivative contracts expired in December 2009.

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

Combined, the certain items related to our Natural Gas Pipelines business segment and described in the footnotes to the table above increased earnings and revenues by \$1.3 million and \$0.4 million, respectively, in the first quarter of 2010, and decreased earnings by \$1.3 million in the first quarter of 2009 (accounting for a \$2.6 million increase in earnings before depreciation, depletion and amortization in the first quarter of 2010, when compared to the first quarter a year ago). Following is information related to the increases and decreases in the segment's (i) remaining \$17.2 million (9%) increase in earnings before depreciation, depletion and amortization; and (ii) remaining \$184.6 million (18%) increase in operating revenues:

Three months ended March 31, 2010 versus Three months ended March 31, 2009

	EBDA		Revenues	
	increase/(decrease)		increase/(decrease)	
	(In millions, except percentages)			
Kinder Morgan Natural Gas Treating	\$ 10.5	n/a	\$ 15.1	n/a
Midcontinent Express Pipeline	5.4	n/a	-	-
Kinder Morgan Louisiana Pipeline	5.3	61 %	17.0	n/a
Casper and Douglas gas processing	2.1	74 %	14.9	106 %
Texas Intrastate Natural Gas Pipeline Group	(9.0)	(8)%	141.3	15 %
All others	2.9	4 %	(3.6)	(5)%
Intrasegment eliminations	-	-	(0.1)	(27)%
Total Natural Gas Pipelines.....	<u>\$ 17.2</u>	<u>9 %</u>	<u>\$ 184.6</u>	<u>18 %</u>

The overall increase in our Natural Gas Pipelines segment's earnings before depreciation, depletion and amortization expenses in the first quarter of 2010 versus the first quarter of 2009 was driven by incremental contributions from our Kinder Morgan Gas Treating operations, and from both our 50%-owned Midcontinent Express and our fully-owned Kinder Morgan Louisiana natural gas pipeline systems. Our first quarter 2010 results were negatively impacted by a portion of our 50%-owned Rockies Express-East pipeline segment being shutdown due to a pipeline girth weld failure that occurred on November 14, 2009. Partial service was restored on January 27, 2010, with full service being restored on February 6, 2010. The shutdown cost us approximately \$15 million in demand charge credits in 2010.

We acquired our Kinder Morgan Gas Treating operations on October 1, 2009, and the operations consist of multiple natural gas treating plants, predominantly located in Texas and Louisiana, which are used to remove impurities and liquids from natural gas in order to meet pipeline quality specifications. Combined, the acquired assets contributed incremental earnings before depreciation, depletion and amortization of \$10.5 million, revenues of \$15.1 million and operating expenses of \$4.6 million.

The incremental equity earnings in the first quarter of 2010 from our investment in the Midcontinent Express pipeline system relates to the start-up of natural gas transportation service in 2009. Midcontinent Express commenced interim service for Zone 1 on April 10, 2009, full Zone 1 service on May 21, 2009, and full Zone 2 service on August 1, 2009.

Our Kinder Morgan Louisiana pipeline system also commenced limited natural gas transportation service in April 2009, and construction was fully completed and transportation service on the system's remaining portions began in full on June 21, 2009. The overall incremental earnings in the first quarter of 2010 consisted of a \$13.3 million increase in operating income (revenues less operating expenses), offset by an \$8.0 million decrease in non-operating other income (primarily consisting of higher non-cash allowances for capital funds used during construction in the first quarter of 2009).

The \$2.1 million (74%) increase in earnings before depreciation, depletion and amortization from our Casper Douglas gas processing operations was attributable to higher natural gas processing margins in the first quarter of 2010.

The \$9.0 million (8%) decrease in earnings from our Texas intrastate natural gas pipeline group in the first quarter of 2010 versus the first quarter of 2009 was primarily due to the following (i) an \$11.1 million decrease in earnings from storage activities; (ii) a \$3.3 million decrease in earnings from lower interest income, due to a one-time natural gas loan to a single customer in 2009; (iii) a \$1.2 million decrease in earnings from higher operating expenses, primarily related to higher pipeline integrity expenses; and (iv) a \$7.3 million increase in earnings from net processing activities.

In the comparable first quarter periods of 2010 and 2009, our Texas intrastate natural gas pipeline group accounted for 45% and 53%, respectively, of the segment's earnings before depreciation, depletion and amortization expenses, 90% and 92%, respectively, of the segment's revenues, and 96% and 97%, respectively, of the segment's operating expenses. The overall changes in both segment revenues and segment operating expenses (which include natural gas costs of sales) in the comparable three month periods primarily relate to the natural gas purchase and sale activities of our intrastate 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. The group both purchases and sells significant volumes of natural gas, which is often stored and/or transported on its pipelines. 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.

CO₂

	Three Months Ended	
	March 31,	
	2010	2009
	(In millions, except operating statistics)	
Revenues(a)	\$ 321.8	\$ 228.9
Operating expenses.....	(79.1)	(66.6)
Earnings from equity investments.....	6.5	5.8
Income tax benefit (expense).....	4.0	(0.7)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments.....	<u>\$ 253.2</u>	<u>\$ 167.4</u>
Carbon dioxide delivery volumes (Bcf)(b)	<u>191.0</u>	<u>212.8</u>
SACROC oil production (gross)(MBbl/d)(c).....	<u>30.0</u>	<u>30.0</u>
SACROC oil production (net)(MBbl/d)(d).....	<u>25.0</u>	<u>25.0</u>
Yates oil production (gross)(MBbl/d)(c)	<u>25.6</u>	<u>26.5</u>
Yates oil production (net)(MBbl/d)(d).....	<u>11.4</u>	<u>11.7</u>
Natural gas liquids sales volumes (net)(MBbl/d)(d).....	<u>9.7</u>	<u>8.9</u>
Realized weighted average oil price per Bbl(e)(f)	<u>\$ 60.50</u>	<u>\$ 43.85</u>
Realized weighted average natural gas liquids price per Bbl(f)(g)	<u>\$ 55.06</u>	<u>\$ 28.10</u>

- (a) 2010 amount includes a \$5.4 million unrealized gain (from an increase in revenues) on derivative contracts used to hedge forecasted crude oil sales.
- (b) Includes Cortez, Central Basin, Canyon Reef Carriers, Centerline and Pecos pipeline 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) Hedge gains/losses for crude oil and natural gas liquids are included with crude oil.
- (g) Includes production attributable to leasehold ownership and production attributable to our ownership in processing plants and third party processing agreements.

Our CO₂ segment's primary businesses involve the production, marketing and transportation of both carbon dioxide (commonly called CO₂) 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 Sales and Transportation Activities and its Oil and Gas Producing Activities.

As described in footnote (a) to the table above, the segment's overall increase in both earnings before depreciation, depletion and amortization expenses and revenues in the three months ended March 31, 2010, compared to the same period of 2009, included an increase of \$5.4 million from an unrealized gain in the first quarter of 2010 on derivative contracts used to hedge forecasted crude oil sales. For each of the segment's two primary businesses, following is information related to the remaining increases and decreases, in the comparable three month periods of 2010 and 2009, of the segment's (i) \$80.4 million (48%) increase in earnings before depreciation, depletion and amortization; and (ii) \$87.5 million (38%) increase in operating revenues:

Three months ended March 31, 2010 versus Three months ended March 31, 2009

	EBDA		Revenues			
	increase/(decrease)		increase/(decrease)			
	(In millions, except percentages)					
Sales and Transportation Activities	\$	7.0	11 %	\$	3.8	6 %
Oil and Gas Producing Activities		73.4	69 %		81.9	47 %
Intrasegment eliminations		-	-		1.8	12 %
Total CO ₂	\$	80.4	48 %	\$	87.5	38 %

The segment's overall increase in earnings before depreciation, depletion and amortization expenses in the comparable three month periods of 2010 versus 2009 was primarily due to 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.

The increase in earnings from oil and gas producing activities in the first quarter of 2010 compared to the first quarter of 2009 was primarily due to the following:

- an increase of \$79.0 million (47%) in combined crude oil and natural gas plant products sales revenues, mainly due to increases of \$16.65 and \$26.96 in our realized weighted average price per barrel for crude oil and natural gas liquids, respectively, and partly to a 9% increase in natural gas liquids sales volumes that was due in part to the lingering effect, in 2009, from the 2008 hurricane season; and
- a decrease of \$8.5 million (12%) due to higher oil and gas related operating expenses, primarily due to higher gas processing costs related to increased gas volumes, and to higher fuel and power expenses.

The segment's overall \$7.0 million (11%) increase in earnings before depreciation, depletion and amortization expenses from its sales and transportation activities for the comparable three month periods was primarily due to (i) a \$4.7 million increase due to lower income tax expenses; (ii) a \$3.8 million increase from higher operating revenues, primarily associated with higher prices received for carbon dioxide sales in the first quarter of 2010; and (iii) a \$2.2 million (20%) decrease due to higher operating expenses. For the CO₂ segment combined, total carbon dioxide delivery volumes decreased 10% compared to the first quarter of 2009. The decrease was mainly due to our lower consumption of new carbon dioxide at both the SACROC and Yates units, although third-party sales actually increased relative to the first quarter last year.

Terminals

	Three Months Ended March 31,	
	2010	2009
	(In millions, except operating statistics)	
Revenues.....	\$ 304.1	\$ 267.9
Operating expenses(a)	(155.9)	(133.6)
Other income	1.3	0.9
Earnings from equity investments.....	0.2	0.1
Interest income and Other, net-income (expense).....	0.9	(0.1)
Income tax expense.....	(0.1)	(0.5)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	<u>\$ 150.5</u>	<u>\$ 134.7</u>
Bulk transload tonnage (MMtons)(b)	<u>21.4</u>	<u>19.3</u>
Ethanol (MMBbl)	<u>15.4</u>	<u>8.6</u>
Liquids leaseable capacity (MMBbl).....	<u>57.9</u>	<u>54.2</u>
Liquids utilization %.....	<u>96.2%</u>	<u>97.3%</u>

- (a) 2010 amount includes a \$0.4 million increase in expense related to storm and flood clean-up and repair activities.
- (b) Volumes for acquired terminals are included for both 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. 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.

The segment's operating results in the first quarter of 2010 include incremental contributions from strategic terminal acquisitions. Since the end of the first quarter of 2009, we have invested \$230.8 million in cash and \$81.7 million in common units to acquire various terminal assets and operations, and combined, our acquired terminal operations accounted for incremental amounts of earnings before depreciation, depletion and amortization of \$6.5 million, revenues of \$14.8 million, and operating expenses of \$8.3 million in the first quarter of 2010. All of the incremental amounts listed above represent the earnings, revenues and expenses from acquired terminals' operations during the first three months of 2010, and do not include increases or decreases during the same months we owned the assets in 2009. For more information on the terminal assets and operations we acquired in the first quarter of 2010, see Note 2 "Acquisitions, Joint Venture Contributions, and Divestitures—Acquisitions" to our consolidated financial statements included elsewhere in this report.

For all other terminal operations (those owned during the first three months of both 2010 and 2009), the certain item described in footnote (a) to the table above accounted for a \$0.4 million decrease in earnings before depreciation, depletion and amortization in the first quarter of 2010, when compared to the first quarter last year. Following is information for these terminal operations, for the comparable three month periods and by terminal operating region, related to (i) the remaining \$9.7 million (7%) increase in earnings before depreciation, depletion and amortization; and (ii) the \$21.4 million (8%) increase in operating revenues:

Three months ended March 31, 2010 versus Three months ended March 31, 2009

	EBDA		Revenues	
	increase/(decrease)		increase/(decrease)	
	(In millions, except percentages)			
West	\$ 8.2	99 %	\$ 13.2	73 %
Mid River	2.4	63 %	5.5	42 %
Southeast	1.6	16 %	3.5	16 %
Gulf Coast	1.5	5 %	2.9	7 %
Texas Petcoke.....	(5.5)	(29)%	(4.7)	(13)%
All others.....	1.5	2 %	0.9	1 %
Intrasegment eliminations	-	-	0.1	60 %
Total Terminals	<u>\$ 9.7</u>	<u>7 %</u>	<u>\$ 21.4</u>	<u>8 %</u>

The overall quarter-to-quarter increase in earnings before depreciation, depletion and amortization expenses from our West region terminals was primarily due to (i) a \$4.9 million overall increase in earnings from our Canadian terminal assets, consisting of a \$2.6 million increase due to incremental business and higher rate tonnage in the first quarter of 2010, and a \$2.3 million increase due to favorable currency impacts from a strengthening of the Canadian dollar since the end of the first quarter last year; and (ii) a \$2.3 million increase in earnings from our Longview, Washington terminal, driven by increased agricultural exports relative to the first quarter of 2009.

The quarter-to-quarter increase in earnings from both our Mid-River and Southeast terminals, which are located in the Central and Southeast regions of the U.S., was primarily driven by incremental business activity (including increased import/export activity) involving the handling and storage of steel and alloy products. Although our steel handling business remains below pre-recession levels, the increased business activity in the first quarter of 2010 reflects a favorable change from the economic downturn that resulted in drops in tonnage, revenues, and earnings at our various owned or operated terminal facilities during 2009. For our Terminals segment combined, bulk traffic tonnage increased by 2.1 million tons (11%) in the first quarter of 2010 versus the same prior year quarter.

The increases in earnings and revenues from our Gulf Coast terminals reflect favorable results from our Pasadena and Galena Park, Texas liquids facilities located along the Houston Ship Channel. The earnings increase was driven by higher liquids warehousing revenues, mainly due to new and incremental customer agreements (at higher rates) and to the completion of various terminal expansion projects that increased liquids tank capacity since the end of the first quarter of 2009. For all liquids terminals combined, expansion projects completed since the end of the first quarter of 2009 increased our liquids terminals' leasable capacity to 57.9 million barrels, up 6.8% from a capacity of 54.2 million barrels at the end of the first quarter last year.

The overall increases in segment earnings before depreciation, depletion and amortization and in segment revenues in the comparable first quarter periods of 2010 and 2009 from terminals owned in both comparable quarters were partly offset by lower operating results from our Texas Petcoke facilities. The decrease in earnings from our Texas Petcoke operations, which provide handling and trucking services for petroleum coke, sulfur and other products in and around Southeast Texas, was primarily due to a lower average rate per ton of petroleum coke moved in the first quarter of 2010. The lower rate in the first quarter of 2010 resulted largely from a decrease in Producer Price Index escalators in certain key customer contracts, when compared to the first quarter last year.

Kinder Morgan Canada

	Three Months Ended March 31,	
	2010	2009
	(In millions, except operating statistics)	
Revenues.....	\$ 59.8	\$ 50.0
Operating expenses.....	(19.5)	(15.2)
Earnings from equity investments.....	0.4	0.3
Interest income and Other, net-income.....	5.8	0.7
Income tax expense(a).....	(1.5)	(16.3)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments.....	<u>\$ 45.0</u>	<u>\$ 19.5</u>
Transport volumes (MMBbl)(b).....	<u>23.8</u>	<u>22.5</u>

(a) 2009 amount includes a \$14.9 million increase in expense primarily due to certain non-cash regulatory accounting adjustments to Trans Mountain's carrying amount of the previously established deferred tax liability.

(b) Represents Trans Mountain pipeline system volumes.

Our Kinder Morgan Canada business segment includes the operations of the Trans Mountain, Express, and Jet Fuel pipeline systems. As described in footnote (a) to the table above, the segment's overall increase in earnings before depreciation, depletion and amortization expenses in the three months ended March 31, 2010, compared to the same period of 2009, included an increase of \$14.9 million primarily related to non-cash regulatory adjustments to income tax expense recorded in the first quarter of 2009. For each of the segment's three primary businesses, following is information related to the increases and decreases, in the comparable three month periods of 2010 and 2009, of the segment's (i) remaining \$10.6 million (31%) increase in earnings before depreciation, depletion and amortization; and (ii) \$9.8 million (20%) increase in operating revenues:

Three months ended March 31, 2010 versus Three months ended March 31, 2009

	EBDA		Revenues	
	increase/(decrease)		increase/(decrease)	
	(In millions, except percentages)			
Trans Mountain Pipeline.....	\$ 9.6	32 %	\$ 9.0	18 %
Jet Fuel Pipeline.....	0.9	226 %	0.8	107 %
Express Pipeline.....	0.1	3 %	-	-
Total Kinder Morgan Canada.....	<u>\$ 10.6</u>	<u>31 %</u>	<u>\$ 9.8</u>	<u>20 %</u>

The segment's overall increases in both earnings before depreciation, depletion and amortization expenses and in revenues in the first quarter of 2010 versus the first quarter of 2009 were primarily due to higher results from its Trans Mountain pipeline system. The quarter-to-quarter increases in Trans Mountain's earnings and revenues were driven primarily by favorable currency impacts, due to a strengthening of the Canadian dollar since the end of the first quarter last year.

Other

	Three Months Ended March 31,	
	2010	2009
	(In millions)	
General and administrative expenses(a).....	\$ 101.1	\$ 82.5
Unallocable interest expense, net of interest income(b).....	\$ 116.3	\$ 104.6
Unallocable income tax expense.....	\$ 2.2	\$ 2.3
Net income attributable to noncontrolling interests(c).....	\$ 2.1	\$ 2.9

- (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. 2010 amount includes (i) a \$1.6 million increase in legal expense associated with certain items such as legal settlements and pipeline failures; (ii) a \$1.4 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); (iii) a \$1.4 million increase in expense for certain asset and business acquisition costs; and (iv) a \$0.3 million decrease in expense related to capitalized overhead costs associated with the 2008 hurricane season. 2009 amount includes (i) a \$1.4 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 \$0.1 million increase in expense for certain Express pipeline system acquisition costs; and (iii) a \$0.6 million decrease in expense related to capitalized overhead costs associated with the 2008 hurricane season.
- (b) 2010 and 2009 amounts include increases in imputed interest expense of \$0.4 million and \$0.5 million, respectively, related to our January 1, 2007 Cochin Pipeline acquisition.
- (c) 2010 and 2009 amounts include decreases of \$2.3 million and \$0.2 million, respectively, in net income attributable to our noncontrolling interests, related to the effect from all of the three month 2010 and 2009 items previously disclosed in the footnotes to the tables included 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.

For the comparable first quarter periods, the certain items described in footnote (a) to the table above increased general and administrative expenses by \$3.2 million in 2010, when compared with the first quarter last year. The remaining \$15.4 million (19%) increase in expenses in the first quarter of 2010 included increases of (i) \$6.6 million from higher employee benefit and payroll tax expenses; (ii) \$3.0 million due to a decrease in capitalized overhead expenses (other than benefits and payroll taxes); and (iii) \$2.5 million due to higher overall corporate insurance expenses. The increase in benefit and payroll tax expenses was mainly due to cost inflation increases on work-based health and insurance benefits, higher wage rates and a larger year-over-year labor force. The drop in capitalized expenses was due to fewer overhead expenses meeting the criteria for capitalization relative to the first quarter of 2009, and the increase in insurance expenses was largely due to an incremental premium tax incurred in the first quarter of 2010.

We report our interest expense as “net,” meaning that we have subtracted unallocated interest income and capitalized interest from our total interest expense to arrive at one interest amount, and after taking into effect the certain item described in footnote (b) to the table above, our unallocable interest expense increased \$11.8 million (11%) in the first quarter of 2010, versus the first quarter last year. The increase in interest expense was attributable to higher average debt balances in the first quarter of 2010, but was partially offset by lower effective interest rates relative to the first quarter of 2009.

Average borrowings for the first three months of 2010 increased 25% compared to the first three months of 2009, primarily due to the capital expenditures and joint venture contributions we have made since the end of the first quarter of 2009, primarily driven by continued investment in our Natural Gas Pipelines, CO₂, and Terminals business segments.

However, due to a general drop in variable interest rates since the end of the first quarter of 2009, the weighted average interest rate on all of our borrowings decreased 15% in the first quarter of 2010, when compared to the first quarter last year. 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 falling interest rates, these swaps result in period-to-period decreases in our interest expense.

As of March 31, 2010, approximately 55% of our \$11,016.4 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

We have consistently generated strong cash flow from operations—generating \$514.8 million and \$452.4 million in cash from operations in the first three months of 2010 and 2009, respectively. We provide for additional liquidity by maintaining (i) an adequate cash balance (we had \$134.4 million of cash and cash equivalents on hand as of March 31, 2010); (ii) access to both long-term debt and equity funding sources; and (iii) a committed \$1.79 billion senior unsecured revolving bank credit facility, discussed below in both “—Credit Ratings and Capital Market Liquidity” and “—Short-term Liquidity.”

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, 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. Currently, our long-term corporate debt credit rating is BBB (stable), Baa2 (negative) and BBB (stable), at Standard & Poor’s Ratings Services, Moody’s Investors Service, Inc. and Fitch Inc., respectively. During the first quarter of 2009, we amended our \$1.85 billion bank credit facility to remove Lehman Brothers Commercial Bank as a lender, thus reducing the facility by \$63.3 million.

On February 25, 2010, Standard & Poor’s revised its outlook on our long-term credit rating to stable from negative, affirmed our long-term credit rating at BBB, and raised our short-term credit rating to A-2 from A-3. The rating agency’s revisions reflected its expectations that our financial profile will improve due to lower guaranteed debt obligations and higher expected cash flows associated with the completion and start-up of the Rockies Express, Midcontinent Express and Kinder Morgan Louisiana natural gas pipeline systems. As a result of this upward revision to our short-term rating, we currently have limited access to the commercial paper market that was not available prior to this rating change. However,

in the near term, we expect that most of our financing and our short-term liquidity needs will continue to be met primarily through borrowings made under our bank credit facility. 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 the current financial crises, 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

Our principal sources of short-term liquidity are our (i) \$1.79 billion senior unsecured revolving bank credit facility that matures August 18, 2010; and (ii) cash from operations (discussed below in “—Operating Activities”). Borrowings under our bank credit facility can be used for general partnership purposes and as a backup for our commercial paper program. The facility can be amended to allow for borrowings of up to \$2.04 billion (after reductions for the lending commitments made by Lehman Brothers Commercial Bank, as discussed above in “—Credit Ratings and Capital Market Liquidity”). We plan to negotiate a renewal of our credit facility before its maturity date.

Our outstanding short-term debt as of March 31, 2010 was \$1,734.4 million, primarily consisting of (i) \$700.0 million in principal amount of 6.75% senior notes that mature March 15, 2011; (ii) \$675.0 million in outstanding borrowings under our bank credit facility; (iii) \$250.0 million in principal amount of 7.50% senior notes that mature November 1, 2010; and (iv) \$65.0 million of commercial paper borrowings. As of December 31, 2009, our outstanding short-term debt was \$594.7 million.

We provide for additional liquidity by maintaining a sizable amount of excess borrowing capacity related to our bank credit facility. After reduction for (i) our letters of credit; (ii) combined borrowings under our credit facility and our commercial paper program; and (iii) the lending commitments made by Lehman Brothers Commercial Bank, the remaining available borrowing capacity under our bank credit facility was \$793.4 million as of March 31, 2010. This remaining borrowing capacity allows us to manage our day-to-day cash requirements and any anticipated obligations, and currently, we believe our liquidity to be adequate.

Working capital—current assets minus current liabilities—can also be used to measure how much in liquid assets a company has available to build its business, and we had working capital deficits of \$1,853.4 million as of March 31, 2010 and \$772.9 million as of December 31, 2009. The unfavorable change from year-end 2009 was primarily due to our higher short-term debt obligations as of March 31, 2010 (discussed above). 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 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 to our common unitholders, Class B unitholders 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.

From time to time we issue long-term debt securities, often referred to as our senior notes. All of our senior notes issued to date, other than those issued by our subsidiaries and operating partnerships, generally have the same terms, except for interest rates, maturity dates and prepayment premiums.

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, 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.

As of March 31, 2010 and December 31, 2009, the net carrying value of the various series of our senior notes was \$10,125.9 million and \$10,125.3 million, respectively, and the total liability balance due on the various borrowings of our operating partnerships and subsidiaries was \$150.5 million and \$167.1 million, respectively. For more information on our first quarter 2010 debt related transactions, see Note 4 “Debt” to our consolidated financial statements included elsewhere in this report, and for additional information regarding our debt securities and credit facility, see Note 8 to our consolidated financial statements included in our 2009 Form 10-K. For information on our first quarter 2010 equity issuances, see Note 5 “Partners’ Capital—Equity Issuances” to our consolidated financial statements included elsewhere in this report.

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

Including both sustaining and discretionary spending, our capital expenditures were \$218.8 million in the first quarter of 2010, versus \$420.3 million in the same year-ago period. Our sustaining capital expenditures—defined as capital expenditures which do not increase the capacity of an asset—totaled \$32.7 million in the first quarter of 2010, compared to \$29.4 million for the first quarter of 2009. These sustaining expenditure amounts include our proportionate share of both Rockies Express Pipeline LLC's and Midcontinent Express Pipeline LLC's sustaining capital expenditures—less than \$0.1 million in both first quarter periods. Additionally, our forecasted expenditures for the remaining nine months of 2010 for sustaining capital expenditures are approximately \$168.9 million, including approximately \$0.1 million for our proportionate shares of Rockies Express and Midcontinent Express.

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 and Midcontinent Express can each fund their own cash requirements for expansion capital expenditures through borrowings under their own credit facilities, issuing their own long-term notes, or with proceeds from contributions received from their equity owners.

All of our capital expenditures, with the exception of sustaining capital expenditures, are classified as discretionary. The discretionary capital expenditures reflected in our consolidated statement of cash flows for the first quarter of 2010 and 2009 were \$186.1 million and \$390.9 million, respectively. The period-to-period decrease in discretionary capital expenditures was mainly due to higher capital expenditures made during the first three months of 2009 on both our major natural gas pipeline projects and on expansions and improvements within our Terminals and CO₂ business segments.

Generally, we fund our discretionary capital expenditures and our investment contributions through borrowings under our bank credit facility. To the extent this source of funding is not sufficient, we generally fund additional amounts through the issuance of long-term notes or common units for cash.

Operating Activities

Net cash provided by operating activities was \$514.8 million for the three months ended March 31, 2010, versus \$452.4 million in the comparable period of 2009. The period-to-period increase of \$62.4 million (14%) in cash provided by operating activities primarily consisted of:

- a \$135.6 million increase in cash from overall higher partnership income—after adjusting for the following five non-cash items: (i) depreciation, depletion and amortization expenses; (ii) undistributed earnings from equity investees; (iii) income from the allowance for equity funds used during construction; (iv) income from sales or casualties of property, plant and equipment and other net assets; and (v) a \$158.0 million expense related to rate case liability adjustments recorded in the first quarter of 2010. The period-to-period increase in partnership income from our five reportable business segments in the first three months of 2010 versus the first three months of 2009 is discussed above in “—Results of Operations” (including all of the certain items disclosed in the associated table footnotes);
- an \$85.8 million increase in cash inflows relative to net changes in working capital items, primarily driven by a \$76.2 million increase from higher net cash inflows from the collection and payment of trade and related party receivables and payables. The increase in cash from changes in working capital items also included (i) a \$22.0 million increase in cash due to higher reductions, in the first quarter of 2009, in deferred revenue obligations; and (ii) a \$26.3 million decrease in cash due to higher interest payments in the first quarter of 2010 (net of interest collections), due to higher average borrowings (partially offset by lower average interest rates) relative to the first quarter a year ago; and
- a \$144.4 million decrease in cash from an interest rate swap termination payment we received in January 2009, when we terminated a fixed-to-variable interest rate swap agreement having a notional principal amount of \$300 million and a maturity date of March 15, 2031.

Investing Activities

Net cash used in investing activities was \$494.1 million for the three month period ended March 31, 2010, versus \$503.4 million in the comparable 2009 period. The \$9.3 million (2%) decrease in cash used in investing activities in the first three months of 2010 compared to the first three months of 2009 was attributable to:

- a \$201.5 million decrease in cash used for capital expenditures—largely due to the higher investment undertaken in the first quarter of 2009 to construct our Kinder Morgan Louisiana Pipeline and to expand and improve our Terminals business segment;
- a \$57.3 million decrease in cash used due to higher capital distributions (distributions in excess of cumulative earnings) received from equity investments in the first quarter of 2010—chiefly due to an incremental capital distribution of \$47.6 million received from Rockies Express Pipeline LLC;
- a \$37.9 million decrease in cash used due to lower contributions to equity investees in the first quarter of 2010. The decrease was driven by a \$40.5 million decrease in combined contributions made to Rockies Express Pipeline LLC, Midcontinent Express Pipeline LLC, and Fayetteville Express Pipeline LLC. In the first quarter of 2010, we contributed \$130.5 million to Rockies Express Pipeline LLC, and during the first quarter last year, we contributed a combined \$171.0 million to these three pipeline projects;
- a \$21.7 million decrease in cash used due to lower period-to-period payments for margin and restricted deposits associated with our energy commodity hedges in the first quarter of 2010, when compared to the first quarter of 2009;
- a \$14.8 million decrease in cash used due to higher net proceeds received in the first quarter of 2010 from property casualty insurance settlements related both to assets damaged during the 2008 hurricane season and to a vessel dock damaged at our International Marine Terminals facility in March 2008;

- a \$225.8 million increase in cash used for the acquisition of assets and investments. The increase was driven by the \$115.7 million in cash we paid to acquire three unit train ethanol handling terminals from US Development Group LLC in January 2010, and by the \$97.0 million we paid to acquire certain terminal assets from Slay Industries in March 2010 (both acquisitions are discussed further in Note 2 to our consolidated financial statements included elsewhere in this report); and
- a \$98.1 million increase in cash used due to repayments we received, in the first quarter of 2009, from a \$109.6 million loan we made in December 2008 to a single customer of our Texas intrastate natural gas pipeline group. We received the remaining \$11.5 million loan balance in the second quarter of 2009.

Financing Activities

Net cash used in financing activities totaled \$29.5 million for the first three months of 2010, and for the first three months of 2009, our financing activities provided us \$54.9 million. The \$84.4 million (154%) overall decrease in cash from the comparable 2009 period was mainly due to:

- a \$287.9 million decrease in cash from lower partnership equity issuances, reflecting the combined proceeds we received, after commissions and underwriting expenses, from the sales of additional common units in the first three months of 2009. The \$287.9 million in proceeds included \$29.9 million from the issuance of 612,083 common units pursuant to our equity distribution agreement with UBS Securities LLC, and \$258.0 million from the issuance of 5,666,000 common units pursuant to an underwritten public offering completed on March 27, 2009. We used the proceeds from these offerings to reduce the borrowings under our bank credit facility;
- a \$52.1 million decrease in cash due to higher partnership distributions paid in the first quarter of 2010, when compared to distributions paid in the first quarter last year. Distributions to all partners, consisting of our common and Class B unitholders, our general partner and noncontrolling interests, totaled \$474.8 million in the first quarter of 2010 and \$422.7 million in the first quarter of 2009.

The increase in distributions was due to increases in both the number of units outstanding (since the record date for the fourth quarter 2008 distribution paid in the first quarter of 2009), and our general partner incentive distributions, which increased due to the higher number of common units and i-units outstanding. Further information regarding our distributions is included below in “—Partnership Distributions;”

- a \$243.9 million increase in cash from overall debt financing activities—which include our issuances and payments of debt and our debt issuance costs. The increase in cash from overall financing activities in the first quarter of 2010 was driven by the \$250.0 million we paid on February 1, 2009 to retire the principal amount of our 6.30% senior notes that matured on that date. Incremental borrowings under our commercial paper program in the first quarter of 2010 were largely offset by lower net borrowings under our bank credit facility; and
- a \$13.7 million increase in cash from net changes in cash book overdrafts—resulting from timing differences on checks issued but not yet presented for payment.

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 in accordance with their respective percentage interests. Our 2009 Form 10-K contains additional information concerning our partnership distributions, including the definition of “Available Cash,” the manner in which our total distributions are divided between our general partner and our limited partners, and the form of distributions to all of our partners, including our noncontrolling interests.

On February 12, 2010, we paid a quarterly distribution of \$1.05 per unit for the fourth quarter of 2009. This distribution matched the \$1.05 distribution per unit we paid in February 2009 for the fourth quarter of 2008. We paid this distribution in cash to our general partner and to our common and Class B unitholders. KMR, our sole i-unitholder, received additional i-units based on the \$1.05 cash distribution per common unit. On April 21, 2010, we declared a cash distribution of \$1.07 per unit for the first quarter of 2010 (an annualized rate of \$4.28 per unit). This distribution was 2% higher than the \$1.05 per unit distribution we made for the first quarter of 2009.

The incentive distribution that we paid on February 12, 2010 to our general partner (for the fourth quarter of 2009) was \$242.3 million. Our general partner's incentive distribution that we paid in February 2009 (for the fourth quarter of 2008) was \$216.6 million. Our general partner's incentive distribution for the distribution that we declared for the first quarter of 2010 is \$249.4 million, and our general partner's incentive distribution for the distribution that we paid for the first quarter of 2009 was \$223.2 million. The period-to-period increases in our general partner incentive distributions resulted from both increased cash distributions per unit and increases in the number of common units and i-units outstanding.

In November 2009, we announced that we expected to declare cash distributions of \$4.40 per unit for 2010, a 4.8% increase over our cash distributions of \$4.20 per unit for 2009. Although the majority of the cash generated by our assets is fee based and is not sensitive to commodity prices, our CO₂ 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 2010 assumes an average West Texas Intermediate (WTI) crude oil price of approximately \$84 per barrel (with some minor adjustments for timing, quality and location differences) in 2010, 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 2010 budget), we currently expect to realize an average WTI crude oil price of approximately \$85.50 per barrel in 2010. Furthermore, for 2010, we expect that every \$1 change in the average WTI crude oil price per barrel will impact our CO₂ segment's cash flows by approximately \$6 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 2009.

We do not expect the \$4.40 per unit distribution to our limited partners for 2010 to be impacted by any settlement payment we may be required to make for reparations sought by shippers on our West Coast Products Pipelines' interstate pipelines due to the support of our general partner. Our general partner has agreed to bear approximately \$100 million of the settlement impact in order to maintain distributions to our limited partners and to preserve our cumulative cash generated in excess of distributions. This will be achieved through a distribution of cash from an interim capital transaction, which is described both in our partnership agreement and in Note 10 to our consolidated financial statements included elsewhere in this report.

Off Balance Sheet Arrangements

Except as set forth under “—Contingent Debt—Rockies Express Pipeline LLC Debt—Subsequent Event” in Note 4 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, 2009 in our 2009 Form 10-K.

Recent Accounting Pronouncements

Please refer to Note 12 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 or the California Public Utilities Commission;
- 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 and the Alberta, Canada 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 pronouncements 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, 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;
- 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 Item 1A “Risk Factors” of our 2009 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 2009 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, 2009, in Item 7A of our 2009 Form 10-K. For more information on our risk management activities, see Note 6 to our consolidated financial statements included elsewhere in this report.

Item 4. Controls and Procedures.

As of March 31, 2010, our management, including our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Securities Exchange Act of 1934. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Based upon and as of the date of the evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that the design and operation of our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed in the reports we file and submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported as and when required, and is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. There has been no change in our internal control over financial reporting during the quarter ended March 31, 2010 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 2009 Form 10-K.

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

On January 15, 2010, we issued 1,287,287 common units as part of the purchase price for three ethanol handling train terminals that we acquired from US Development Group LLC. The total purchase price for the acquired operations was approximately \$200.8 million, consisting of \$115.7 million in cash, \$81.7 million in common units, and \$3.4 million in assumed liabilities. The common units were issued to a single accredited investor in a transaction not involving a public offering, 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.

None.

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.
- *4.2 — Registration Rights Agreement, dated as of January 15, 2010, between US Development Group LLC and Kinder Morgan Energy Partners, L.P. (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P. Registration Statement on Form S-3 filed January 19, 2010).
- 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 month periods ended March 31, 2010 and 2009; (ii) our Consolidated Balance Sheets as of March 31, 2010 and December 31, 2009; (iii) our Consolidated Statements of Cash Flows for the three months ended March 31, 2010 and 2009; and (iv) the notes to our Consolidated Financial Statements, tagged as blocks of text.

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

