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

F O R M 10-Q

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

For the quarterly period ended **September 30, 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	**76-0380342**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Securities Exchange Act of 1934. Large accelerated filer [X] 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 [X]

The Registrant had 217,298,582 common units outstanding as of October 29, 2010.

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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 September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Revenues				
Natural gas sales	$ 965.7	$ 686.2	$ 2,831.3	$ 2,291.8
Services	758.7	690.2	2,248.9	2,003.7
Product sales and other	335.6	284.3	1,070.9	797.0
Total Revenues	2,060.0	1,660.7	6,151.1	5,092.5
Operating Costs, Expenses and Other				
Gas purchases and other costs of sales	964.6	665.2	2,829.2	2,240.5
Operations and maintenance	328.3	280.3	1,098.7	797.6
Depreciation, depletion and amortization	224.1	202.9	674.6	616.2
General and administrative	93.6	83.7	288.1	238.8
Taxes, other than income taxes	41.9	36.4	128.1	98.8
Other expense (income)	0.2	(14.5)	(6.4)	(18.1)
Total Operating Costs, Expenses and Other	1,652.7	1,254.0	5,012.3	3,973.8
Operating Income	407.3	406.7	1,138.8	1,118.7
Other Income (Expense)				
Earnings from equity investments	53.7	59.8	155.6	139.9
Amortization of excess cost of equity investments	(1.4)	(1.4)	(4.3)	(4.3)
Interest, net	(129.0)	(103.0)	(357.4)	(296.2)
Other, net	5.4	12.9	9.8	43.8
Total Other Income (Expense)	(71.3)	(31.7)	(196.3)	(116.8)
Income Before Income Taxes	336.0	375.0	942.5	1,001.9
Income Taxes	(13.6)	(11.3)	(27.6)	(42.8)
Net Income	322.4	363.7	914.9	959.1
Net Income Attributable to Noncontrolling Interests	(1.6)	(4.2)	(7.6)	(11.9)
Net Income Attributable to Kinder Morgan Energy Partners, L.P.	$ 320.8	$ 359.5	$ 907.3	$ 947.2
Calculation of Limited Partners' Interest in Net Income Attributable to Kinder Morgan Energy Partners, L.P.:				
Net Income Attributable to Kinder Morgan Energy Partners, L.P.	$ 320.8	$ 359.5	$ 907.3	$ 947.2
Less: General Partner's Interest	(267.3)	(236.2)	(609.0)	(692.7)
Limited Partners' Interest in Net Income	$ 53.5	$ 123.3	$ 298.3	$ 254.5
Limited Partners' Net Income per Unit	$ 0.17	$ 0.43	$ 0.98	$ 0.92
Weighted Average Number of Units Used in Computation of Limited Partners' Net Income per Unit	310.7	286.6	304.7	277.9
Per Unit Cash Distribution Declared	$ 1.11	$ 1.05	$ 3.27	$ 3.15

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)

	September 30, 2010 (Unaudited)	December 31, 2009
ASSETS		
Current assets		
Cash and cash equivalents	$ 191.6	$ 146.6
Restricted deposits	-	15.2
Accounts, notes and interest receivable, net	764.7	902.1
Inventories	84.0	71.9
Gas in underground storage	46.2	43.5
Fair value of derivative contracts	50.0	20.8
Other current assets	38.6	44.6
Total current assets	1,175.1	1,244.7
Property, plant and equipment, net	14,437.0	14,153.8
Investments	3,821.4	2,845.2
Notes receivable	192.1	190.6
Goodwill	1,223.8	1,149.2
Other intangibles, net	309.1	218.7
Fair value of derivative contracts	715.8	279.8
Deferred charges and other assets	178.3	180.2
Total Assets	$ 22,052.6	$ 20,262.2
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Current portion of debt	$ 1,409.8	$ 594.7
Cash book overdrafts	30.4	34.8
Accounts payable	582.0	614.8
Accrued interest	96.8	222.4
Accrued taxes	90.6	57.8
Deferred revenues	86.3	76.0
Fair value of derivative contracts	213.1	272.0
Accrued other current liabilities	171.1	145.1
Total current liabilities	2,680.1	2,017.6
Long-term liabilities and deferred credits		
Long-term debt		
Outstanding	10,278.6	9,997.7
Value of interest rate swaps	952.7	332.5
Total Long-term debt	11,231.3	10,330.2
Deferred income taxes	237.0	216.8
Fair value of derivative contracts	125.1	460.1
Other long-term liabilities and deferred credits	454.1	513.4
Total long-term liabilities and deferred credits	12,047.5	11,520.5
Total Liabilities	14,727.6	13,538.1
Commitments and contingencies (Notes 4 and 10)		
Partners' Capital		
Common units	4,311.9	4,057.9
Class B units	66.7	78.6
i-units	2,768.6	2,681.7
General partner	238.7	221.1
Accumulated other comprehensive loss	(144.2)	(394.8)
Total Kinder Morgan Energy Partners, L.P. partners' capital	7,241.7	6,644.5
Noncontrolling interests	83.3	79.6
Total Partners' Capital	7,325.0	6,724.1
Total Liabilities and Partners' Capital	$ 22,052.6	$ 20,262.2

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)

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Cash Flows From Operating Activities		
Net Income	$ 914.9	$ 959.1
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	674.6	616.2
Amortization of excess cost of equity investments	4.3	4.3
Income from the allowance for equity funds used during construction	(0.7)	(22.6)
Income from the sale or casualty of property, plant and equipment and other net assets	(6.4)	(18.1)
Earnings from equity investments	(155.6)	(139.9)
Distributions from equity investments	154.9	153.1
Proceeds from termination of interest rate swap agreements	-	144.4
Changes in components of working capital:		
Accounts receivable	105.0	227.3
Inventories	(12.8)	(11.8)
Other current assets	12.9	(52.7)
Accounts payable	(26.8)	(346.2)
Accrued interest	(125.6)	(81.3)
Accrued taxes	32.7	35.4
Accrued liabilities	2.8	(59.0)
Rate reparations, refunds and other litigation reserve adjustments	(48.3)	(15.5)
Other, net	1.4	(15.7)
Net Cash Provided by Operating Activities	1,527.3	1,377.0
Cash Flows From Investing Activities		
Acquisitions of investments	(929.7)	-
Acquisitions of assets	(243.1)	(27.5)
Repayments from customers	-	109.6
Capital expenditures	(722.1)	(1,075.4)
Sale or casualty of property, plant and equipment, and other net assets net of removal costs	21.5	9.1
Net Proceeds from (Investments in) margin deposits	21.7	(13.2)
Contributions to equity investments	(209.8)	(1,619.1)
Distributions from equity investments in excess of cumulative earnings	153.2	-
Net Cash Used in Investing Activities	(1,908.3)	(2,616.5)
Cash Flows From Financing Activities		
Issuance of debt	5,704.2	5,871.9
Payment of debt	(4,601.0)	(4,025.4)
Repayments from related party	1.3	2.5
Debt issue costs	(22.5)	(12.3)
Decrease in cash book overdrafts	(4.4)	(9.6)
Proceeds from issuance of common units	636.6	815.5
Contributions from noncontrolling interests	10.2	11.0
Distributions to partners and noncontrolling interests:		
Common units	(674.2)	(599.2)
Class B units	(17.1)	(16.7)
General Partner	(591.4)	(680.3)
Noncontrolling interests	(16.7)	(16.3)
Other, net	-	(0.3)
Net Cash Provided by Financing Activities	425.0	1,340.8
Effect of Exchange Rate Changes on Cash and Cash Equivalents	1.0	5.0
Net increase in Cash and Cash Equivalents	45.0	106.3
Cash and Cash Equivalents, beginning of period	146.6	62.5
Cash and Cash Equivalents, end of period	$ 191.6	$ 168.8
Noncash Investing and Financing Activities		
Assets acquired by the assumption or incurrence of liabilities	$ 12.5	$ 3.7
Assets acquired by the issuance of common units	$ 81.7	$ 5.0
Supplemental Disclosures of Cash Flow Information		
Cash paid during the period for interest (net of capitalized interest)	$ 456.6	$ 387.8
Cash (received) paid during the period for income taxes	$ (2.8)	$ 2.3

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., as 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 a wholly-owned subsidiary of 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.

2. Acquisitions, Joint Ventures, 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 $201.1 million, consisting of $114.3 million in cash, $81.7 million in common units, and $5.1 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 joint 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 $5.4 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 $101.6 million, consisting of $97.0 million in cash, assumed liabilities of $1.6 million, and an obligation to pay additional cash consideration of $3.0 million in years 2013 through 2019, contingent upon the purchased assets providing us an agreed-upon amount of earnings during the three years following the acquisition. Including accrued interest, we expect to pay approximately $2.0 million of this contingent consideration 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, we assigned $67.9 million of our purchase price to "Property, Plant and Equipment, net"; $24.6 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.

KinderHawk Field Services LLC Acquisition

On May 21, 2010, we completed our previously announced 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. On that date, we paid an aggregate consideration of $921.4 million in cash for our 50% equity ownership interest, and pursuant to the provisions of the joint venture formation and contribution agreement, our payment included approximately $46.4 million for both estimated capital expenditures and estimated net cash outflows from operating activities for the period January 1, 2010 through May 21, 2010. In the fourth quarter of 2010, we received net proceeds of $3.9 million for the final settlement of these estimated amounts.

During a short transition period, Petrohawk continued to operate the business, and effective October 1, 2010, a newly formed company named KinderHawk Field Services LLC, owned 50% by us and 50% by Petrohawk, assumed the joint venture operations. The acquisition complemented and expanded our existing natural gas gathering and treating businesses, and we assigned our entire purchase price to "Investments" on our accompanying consolidated balance sheet as of September 30, 2010 (including $144.8 million of equity method goodwill, representing the excess of our investment cost over our proportionate share of the fair value of the joint venture's identifiable net assets). Our investment and our pro rata share of the joint venture's operating results are included as part of our Natural Gas Pipelines business segment.

Direct Fuels Terminal Acquisition

On July 22, 2010, we acquired a terminal with ethanol tanks, a truck rack and additional acreage in Dallas, Texas, from Direct Fuels Partners, L.P. for an aggregate consideration of $16 million, consisting of $15.9 million in cash and an assumed property tax liability of $0.1 million. The acquired terminal facility is connected to and complements the Dallas, Texas unit train terminal we acquired from USD Development Group LLC in January 2010 (described above in "—USD Terminal Acquisition). All of the acquired assets are included in our Terminals business segment, and 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 $5.3 million of our combined purchase price to "Property, Plant and Equipment, net." The remaining $10.7 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.

Gas-Chill, Inc. Asset Acquisition

On September 1, 2010, we acquired the natural gas treating assets of Gas-Chill, Inc. for an aggregate consideration of $13.1 million, consisting of $10.5 million in cash paid on closing, and an obligation to pay a holdback amount of $2.6 million within eighteen months from closing. The acquired assets primarily consist of more than 100 mechanical refrigeration natural gas hydrocarbon dew point control units that are used to remove hydrocarbon liquids from natural gas streams prior to entering transmission pipelines. The refrigeration control units are designed to extract natural gas liquids from the inlet gas stream and retain the liquids if there are significant enough quantities to economically justify recovery. The units are constructed on a modular basis for ease of transport and installation requirements and are located in 12 different states. The acquisition complemented and expanded the existing natural gas treating operations offered by our Texas intrastate natural gas pipeline group, and all of the acquired assets are included in our Natural Gas Pipelines business segment. We assigned $8.0 million of our purchase price to "Property, Plant and Equipment, net" and the remaining $5.1 million to "Other intangibles, net" (representing both a technology-based asset and customer-related contract values).

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, 2009 as if they had occurred as of January 1, 2009 is not presented because it would not be materially different from the information presented in our accompanying consolidated statements of income.

Acquisitions Subsequent to September 30, 2010

Allied Concrete Bulk Terminal Assets

On October 1, 2010, we acquired certain bulk terminal assets and real property located in Chesapeake, Virginia, from Allied Concrete Products, LLC and Southern Concrete Products, LLC for an aggregate consideration of $8.6 million, consisting of $8.1 million in cash and an assumed environmental liability of $0.5 million. The acquired terminal facility is situated on 42 acres of land and can handle approximately 250,000 tons of material annually, including pumice, aggregates and sand. The acquisition complements the bulk commodity handling operations at our nearby Elizabeth River terminal, also located in Chesapeake, and all of the acquired assets will be included in our Terminals business segment.

Chevron Refined Products Terminal Assets

On October 8, 2010, we acquired four separate refined petroleum products terminals from Chevron U.S.A. Inc. for an aggregate consideration of approximately $40 million, including inclusion capital. Combined, the terminals have storage capacity of approximately 650,000 barrels for gasoline, diesel fuel and jet fuel. Chevron has entered into long-term contracts with us to terminal product at the terminals. The acquisition complements and expands our existing refined petroleum products assets, and all of the acquired assets will be included in our Products Pipelines business segment. Our subsidiary Kinder Morgan Southeast Terminals LLC acquired terminal facilities located in Chattanooga, Tennessee and Columbus, Georgia, and both of these terminals will be included in our Southeast terminal operations. Our subsidiary SFPP, L.P. acquired terminals located in Tucson and Phoenix, Arizona, and each of these two terminals will be included in our Pacific operations. In the fourth quarter of 2010, we expect to measure the identifiable tangible assets acquired and liabilities assumed at fair value on the acquisition date.

Joint Ventures

Eagle Ford Gathering LLC

On May 14, 2010, we and Copano Energy, L.L.C. entered into formal agreements for a joint venture to provide natural gas gathering, transportation and processing services to natural gas producers in the Eagle Ford Shale formation in south Texas. The joint venture is named Eagle Ford Gathering LLC, and we own 50% of the equity in the project (a 50% member interest in Eagle Ford Gathering LLC), and Copano owns the remaining 50% interest. Copano serves as operator and managing member of Eagle Ford Gathering LLC. We and Copano have committed approximately 375 million cubic feet per day of natural gas capacity to the joint venture through 2024 for both transportation on our natural gas pipeline that extends from Laredo to Katy, Texas, and for processing at Copano's natural gas processing plant located in Colorado County, Texas.

On July 6, 2010, Eagle Ford Gathering LLC announced the execution of a definitive long-term, fee-based gas services agreement with SM Energy Company. According to the provisions of the agreement, SM Energy will commit Eagle Ford production from its assets located in LaSalle, Dimmitt, and Webb Counties, Texas up to a maximum level of 200 million cubic feet per day over a ten year term. In addition, Eagle Ford Gathering LLC will construct approximately 85 miles of 24-inch and 30-inch diameter pipeline to serve SM Energy's acreage in the western Eagle Ford Shale formation and to connect it to our Freer compressor station located in Duval County, Texas, and will construct 25 miles of 24-inch and 30-inch diameter pipeline to access additional acreage. The pipeline is expected to begin service during the summer of 2011.

Combined, we and Copano will invest approximately $175 million for the expanded project. Eagle Ford Gathering LLC is evaluating several opportunities to expand its ability to offer producers in the Eagle Ford Shale play additional midstream services. As of September 30, 2010, our capital contributions (and net equity investment) in Eagle Ford Gathering LLC totaled $9.5 million.

Midcontinent Express Pipeline LLC

On May 26, 2010, Energy Transfer Partners, L.P. transferred to Regency Energy Partners LP (i) a 49.9% ownership interest in Midcontinent Express Pipeline LLC; and (ii) a one-time right to purchase its remaining 0.1% ownership interest in Midcontinent Express Pipeline LLC on May 26, 2011. As a result of this transfer, Energy Transfer Partners, L.P. now owns a 0.1% ownership interest in Midcontinent Express Pipeline LLC. Our subsidiary, Kinder Morgan Operating L.P., "A," continues to own the remaining 50% ownership interest in Midcontinent Express Pipeline LLC, and since there was no change in our ownership interest, we did not record any equity method adjustments as a result of the ownership change between Regency Energy Partners LP and Energy Transfer Partners, L.P.

Divestitures Subsequent to September 30, 2010

Effective October 1, 2010, Westlake Petrochemicals LLC, a wholly-owned subsidiary of Westlake Chemical Corporation, exercised an option it held to purchase a 50% ownership interest in our Cypress Pipeline. Accordingly, we sold a 50% interest in our subsidiary, Cypress Interstate Pipeline LLC, to Westlake and we received proceeds of $10.2 million. At the time of the sale, the carrying value of the net assets of Cypress Interstate Pipeline LLC totaled $20.4 million and consisted mostly of property, plant and equipment. In the fourth quarter of 2010, we expect to recognize an approximate $8.5 million gain from this sale, with the entire amount related to the remeasurement of our retained investment to its fair value. Due to the loss of control of Cypress Interstate Pipeline LLC, we now account for our retained investment under the equity method of accounting and we recognize the retained investment at its fair value. Our gain amount represents the excess of the fair value of our retained investment ($18.7 million) over its carrying value ($10.2 million).

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) CO_2; (v) Terminals; and (vi) Kinder Morgan Canada.

There were no impairment charges resulting from our May 31, 2010 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 nine months ended September 30, 2010 are summarized as follows (in millions):

	Products Pipelines	Natural Gas Pipelines	CO_2	Terminals	Kinder Morgan Canada	Total
Historical Goodwill.	$ 263.2	$ 337.0	$ 46.1	$ 266.9	$ 613.1	$ 1,526.3
Accumulated impairment losses(a)	-	-	-	-	(377.1)	(377.1)
Balance as of December 31, 2009	263.2	337.0	46.1	266.9	236.0	1,149.2
Acquisitions	-	-	-	69.6	-	69.6
Disposals.	-	-	-	-	-	-
Currency translation adjustments	-	-	-	-	5.0	5.0
Balance as of September 30, 2010	$ 263.2	$ 337.0	$ 46.1	$ 336.5	$ 241.0	$ 1,223.8

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

In addition, we identify any premium or excess cost we pay over our proportionate share of the underlying fair value of net assets acquired and accounted for as investments under the equity method of accounting. This premium or excess cost is referred to as equity method goodwill and is also not subject to amortization but rather to impairment testing. For all investments we own containing equity method goodwill, no event or change in circumstances that may have a significant adverse effect on the fair value of our equity investments has occurred during the first nine months of 2010, and as of September 30, 2010 and December 31, 2009, we reported $283.0 million and $138.2 million, respectively, in equity method goodwill within the caption "Investments" in our accompanying consolidated balance sheets. The increase in our equity method goodwill since December 31, 2009 was due to the goodwill included in the purchase of our 50% ownership interest in KinderHawk Field Services, LLC, discussed in Note 2.

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):

	September 30, 2010	December 31, 2009
Customer relationships, contracts and agreements		
Gross carrying amount	$ 395.1	$ 273.0
Accumulated amortization	(100.5)	(67.1)
Net carrying amount	294.6	205.9
Technology-based assets, lease value and other		
Gross carrying amount	17.9	15.7
Accumulated amortization	(3.4)	(2.9)
Net carrying amount	14.5	12.8
Total Other intangibles, net	$ 309.1	$ 218.7

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 effects of obsolescence, new technology, and competition. For the three and nine months ended September 30, 2010, the amortization expense on our intangibles totaled $11.5 million and $33.9 million, respectively, and for the same prior year periods, the amortization expense on our intangibles totaled $3.6 million and $10.5 million, respectively. As of September 30, 2010, the weighted average amortization period for our intangible assets was approximately 14 years, and our estimated amortization expense for these assets for each of the next five fiscal years (2011 – 2015) is approximately $39.0 million, $33.6 million, $29.7 million, $26.4 million and $23.5 million, respectively.

4. Debt

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

The net carrying amount of our debt (including both short-term and long-term amounts and excluding the value of interest rate swap agreements) as of September 30, 2010 and December 31, 2009 was $11,688.4 million and $10,592.4 million, respectively. The weighted average interest rate on all of our borrowings (both short-term and long-term) was approximately 4.42% during the third quarter of 2010 and approximately 4.35% during the third quarter of 2009. For the first nine months of 2010 and 2009, the weighted average interest rate on all of our borrowings (both short-term and long-term) was approximately 4.34% and 4.66%, respectively.

Our outstanding short-term debt as of September 30, 2010 was $1,409.8 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 $699.9 million as of September 30, 2010); (ii) $414.8 million of commercial paper borrowings; (iii) $250.0 million in principal amount of 7.50% senior notes due November 1, 2010; (iv) $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); (v) a $9.2 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); (vi) a $7.2 million portion of 5.23% long-term senior notes (our subsidiary Kinder Morgan Texas Pipeline, L.P. is the obligor on the notes); and (vii) $5.0 million in principal amount of 6.00% Development Revenue Bonds due January 1, 2011 and 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

On June 23, 2010, we successfully renegotiated our previous $1.79 billion five-year unsecured revolving bank credit facility that was due August 18, 2010, replacing it with a new $2.0 billion three-year, senior unsecured revolving credit facility that expires June 23, 2013. Similar to our previous facility, our $2.0 billion credit facility is with a syndicate of financial institutions, and the facility permits us to obtain bids for fixed rate loans from members of the lending syndicate. Wells Fargo Bank, National Association is the administrative agent, and borrowings under the credit facility can be used for general partnership purposes and as a backup for our commercial paper program.

The covenants of this credit facility are substantially similar to the covenants of our previous facility; however, the interest rates for borrowings under this facility have increased from our previous facility. Interest on the 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. The credit facility can be amended to allow for borrowings of up to $2.3 billion.

We had no borrowings under our $2.0 billion, senior unsecured revolving credit facility as of September 30, 2010, although the amount available for borrowing under our credit facility was reduced as further discussed below. As of December 31, 2009, the outstanding balance under our previous $1.79 billion credit facility was $300 million, and the weighted average interest rate on those borrowings was 0.59%.

As of September 30, 2010, the amount available for borrowing under our credit facility was reduced by a combined amount of $636.9 million, consisting of $414.8 million of commercial paper borrowings and $222.1 million of letters of credit, consisting of: (i) a $100.0 million letter of credit that supports certain proceedings with the California Public Utilities Commission involving refined products tariff charges on the intrastate common carrier operations of our Pacific operations' pipelines in the state of California; (ii) a combined $89.4 million in three letters of credit that support tax-exempt bonds; (iii) a $16.1 million letter of credit that supports our indemnification obligations on the Series D note borrowings of Cortez Capital Corporation; and (iv) a combined $16.6 million in other letters of credit supporting other obligations of us and our subsidiaries.

Commercial Paper Program

Our commercial paper program provides for the issuance of $2 billion of commercial paper. 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 September 30, 2010, we had $414.8 million of commercial paper outstanding with an average interest rate of 0.66%. In the near term, we expect that our short-term liquidity and financing needs will be met through a combination of borrowings made under our bank credit facility and our commercial paper program.

Senior Notes

On May 19, 2010, we completed a public offering of senior notes. We issued a total of $1 billion in principal amount of senior notes in two separate series, consisting of $600 million of 5.30% notes due September 15, 2020, and $400 million of 6.55% notes due September 15, 2040. We received proceeds from the issuance of the notes, after underwriting discounts and commissions, of $993.1 million, and we used the proceeds to reduce the borrowings under our commercial paper program and our bank credit facility.

Interest Rate Swaps

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

Contingent Debt

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

As of September 30, 2010, our contingent debt obligations with respect to these investments, as well as our obligations with respect to related letters of credit, are summarized below (dollars in millions):

Entity	Our Ownership Interest	Investment Type	Total Entity Debt	Our Contingent Share of Entity Debt(a)
Fayetteville Express Pipeline LLC(b)	50%	Limited Liability	$ 847.0(c)	$ 423.5
Cortez Pipeline Company(d)	50%	General Partner	$ 141.1(e)	$ 86.7(f)
Midcontinent Express Pipeline LLC(g)	50%	Limited Liability	$ 881.2(h)	$ 41.1(i)
Nassau County, Florida Ocean Highway and Port Authority(j)	N/A	N/A	N/A	$ 19.8(k)

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

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

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

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

(e) Amount consists of (i) $32.1 million of fixed rate Series D notes due May 15, 2013 (interest on the Series D notes is paid annually and based on an average interest rate of 7.14% per annum); (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 three-month LIBOR plus a spread); and (iii) $9.0 million of outstanding borrowings under a $40 million committed revolving bank credit facility that is also due December 11, 2012.

(f) We are severally liable for our percentage ownership share (50%) of the Cortez Pipeline Company debt ($70.6 million). In addition, as of September 30, 2010, Shell Oil Company shares our several guaranty obligations jointly and severally for $32.1 million of Cortez's debt balance related to the Series D notes; however, we are obligated to indemnify Shell for the liabilities it incurs in connection with such guaranty. Accordingly, as of September 30, 2010, we have a letter of credit in the amount of $16.1 million issued by JP Morgan Chase, in order to secure our indemnification obligations to Shell for 50% of the Cortez debt balance of $32.1 million related to the Series D notes.

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

(g) Midcontinent Express Pipeline LLC is a limited liability company and the owner of the Midcontinent Express natural gas pipeline system. The remaining limited liability company member interests in Midcontinent Express Pipeline LLC are owned by Regency Energy Partners, L.P. and Energy Transfer Partners, L.P.

(h) Amount consists of (i) outstanding borrowings of $82.2 million under a $175.4 million, unsecured revolving bank credit facility that is due February 28, 2011; and (ii) an aggregate carrying value of $799.0 million in fixed rate senior notes issued by Midcontinent Express Pipeline LLC in a private offering in September 2009. All payments of principal and interest in respect of these senior notes are the sole obligation of Midcontinent Express. Noteholders have no recourse against us or the other member owners of Midcontinent Express Pipeline LLC for any failure by Midcontinent Express to perform or comply with its obligations pursuant to the notes or the indenture.

(i) In addition to our contingent share of entity debt ($41.1 million), there is a letter of credit outstanding to support the construction of the Midcontinent Express natural gas pipeline system. As of September 30, 2010, this letter of credit, issued by the Bank of Tokyo-Mitsubishi UFJ, Ltd., had a face amount of $33.3 million. Our contingent responsibility with regard to this outstanding letter of credit was $16.7 million (50% of total face amount).

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

(k) 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 September 30, 2010, this letter of credit had a face amount of $19.8 million.

We also hold a 50% equity ownership interest in Rockies Express Pipeline LLC, a limited liability company and the owner of the Rockies Express natural gas pipeline system. Subsidiaries of Sempra Energy and ConocoPhillips own the remaining member interests, and pursuant to certain guaranty agreements remaining in effect on December 31, 2009, 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 that is due April 28, 2011. 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.

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

5. Partners’ Capital

Limited Partner Units

As of September 30, 2010 and December 31, 2009, our partners’ capital included the following limited partner units:

	September 30, 2010	December 31, 2009
Common units	217,119,928	206,020,826
Class B units	5,313,400	5,313,400
i-units	90,296,732	85,538,263
Total limited partner units	312,730,060	296,872,489

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 September 30, 2010, our total common units consisted of 200,749,500 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 September 30, 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 September 30, 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 and nine month periods ended September 30, 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 September 30,					
	2010			2009		
	KMP	Noncontrolling interests	Total	KMP	Noncontrolling interests	Total
Beginning Balance	$ 7,023.1	$ 83.1	$ 7,106.2	$ 6,267.7	$ 74.3	$ 6,342.0
Units issued for cash	203.4	-	203.4	146.0	-	146.0
Distributions paid in cash	(333.7)	(4.7)	(338.4)	(448.1)	(5.5)	(453.6)
KMI going-private transaction expenses	1.0	-	1.0	1.5	-	1.5
Cash contributions	-	3.0	3.0	-	2.4	2.4
Other adjustments	(0.1)	-	(0.1)	(0.1)	-	(0.1)
Comprehensive income:						
Net Income	320.8	1.6	322.4	359.5	4.2	363.7
Other comprehensive income (loss):						
Change in fair value of derivatives utilized for hedging purposes	(82.5)	(0.8)	(83.3)	34.7	0.3	35.0
Reclassification of change in fair value of derivatives to net income	47.2	0.4	47.6	20.8	0.2	21.0
Foreign currency translation adjustments	62.2	0.7	62.9	143.0	1.5	144.5
Adjustments to pension and other postretirement benefit plan liabilities	0.3	-	0.3	0.4	-	0.4
Total other comprehensive income	27.2	0.3	27.5	198.9	2.0	200.9
Comprehensive income	348.0	1.9	349.9	558.4	6.2	564.6
Ending Balance	$ 7,241.7	$ 83.3	$ 7,325.0	$ 6,525.4	$ 77.4	$ 6,602.8

	Nine Months Ended September 30,					
	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	5.0	-	5.0
Units issued for cash	636.6	-	636.6	815.5	-	815.5
Distributions paid in cash	(1,282.7)	(16.7)	(1,299.4)	(1,296.2)	(16.3)	(1,312.5)
Adjustments to capital resulting from related party acquisitions	-	-	-	22.9	0.3	23.2
KMI going-private transaction expenses	3.7	-	3.7	4.3	-	4.3
Cash contributions	-	10.2	10.2	-	11.0	11.0
Other adjustments	(0.2)	-	(0.2)	(0.6)	-	(0.6)
Comprehensive income:						
Net Income	907.3	7.6	914.9	947.2	11.9	959.1
Other comprehensive income (loss):						
Change in fair value of derivatives utilized for hedging purposes	83.5	0.9	84.4	(265.9)	(2.7)	(268.6)
Reclassification of change in fair value of derivatives to net income	133.3	1.3	134.6	34.0	0.3	34.3
Foreign currency translation adjustments	35.9	0.4	36.3	215.9	2.2	218.1
Adjustments to pension and other postretirement benefit plan liabilities	(2.1)	-	(2.1)	(2.5)	-	(2.5)
Total other comprehensive income (loss)	250.6	2.6	253.2	(18.5)	(0.2)	(18.7)
Comprehensive income	1,157.9	10.2	1,168.1	928.7	11.7	940.4
Ending Balance	$ 7,241.7	$ 83.3	$ 7,325.0	$ 6,525.4	$ 77.4	$ 6,602.8

During the first nine 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 Ventures, and Divestitures—Acquisitions—USD Terminal Acquisition."

On May 7, 2010, we issued, in a public offering, 6,500,000 of our common units at a price of $66.25 per unit, less commissions and underwriting expenses. After commissions and underwriting expenses, we received net proceeds of $417.4 million for the issuance of these 6,500,000 common units, and we used the proceeds to reduce the borrowings under our commercial paper program and our bank credit facility.

On July 2, 2010, we completed an offering of 1,167,315 of our common units at a price of $64.25 per unit in a privately negotiated transaction. We received net proceeds of $75.0 million for the issuance of these 1,167,315 common units, and we used the proceeds to reduce the borrowings under our commercial paper program and our bank credit facility.

During the three and nine months ended September 30, 2010, we issued 1,899,008 and 2,142,050, respectively, of our common units pursuant to our equity distribution agreement with UBS Securities LLC. After commissions of $1.0 million and $1.1 million, respectively, for the three and nine month periods, we received net proceeds from the issuance of these common units of $128.4 million and $144.2 million, respectively. We used the proceeds to reduce the borrowings under our commercial paper program and our bank credit facility. For additional information regarding our equity distribution agreement, see Note 10 to our consolidated financial statements included in our 2009 Form 10-K.

Equity Issuances Subsequent to September 30, 2010

In October 2010, we issued 178,654 of our common units for the settlement of sales made on or before September 30, 2010 pursuant to our equity distribution agreement. After commissions of $0.1 million, we received net proceeds of $12.1 million for the issuance of these 178,654 common units, and we used the proceeds to reduce the borrowings under our commercial paper program and our bank credit facility.

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 August 13, 2010, we paid a cash distribution of $1.09 per unit to our common unitholders and our Class B unitholders for the quarterly period ended June 30, 2010. KMR, our sole i-unitholder, received a distribution of 1,625,869 i-units from us on August 13, 2010, based on the $1.09 per unit distributed to our common unitholders on that date. The distributions were declared on July 21, 2010, payable to unitholders of record as of July 30, 2010. Our incentive distribution payments to our general partner for the second quarter of 2010 totaled $89.8 million. Our distribution of $1.05 per unit paid on August 14, 2009 for the second quarter of 2009 resulted in incentive distribution payments to our general partner of $231.8 million. Because a portion of our available cash distribution for the second quarter of 2010 was a distribution of cash from interim capital transactions, rather than a distribution of cash from operations, our general partner was not entitled to an incentive distribution of $168.3 million that it would have received if all available cash distributions for the quarter would have consisted of cash from operations. In addition, our general partner waived an incentive distribution amount of $5.3 million related to equity issued to finance our acquisition of a 50% interest in Petrohawk Energy Corporation's natural gas gathering and treating business, and it has agreed not to take incentive distributions related to this acquisition through year-end 2011. In the first nine months of 2010 and 2009, we made incentive distribution payments to our general partner totaling $581.5 million and $671.6 million, respectively.

Subsequent Event

On October 20, 2010, we declared a cash distribution of $1.11 per unit for the quarterly period ended September 30, 2010. The distribution will be paid on November 12, 2010, to unitholders of record as of October 29, 2010. Our common unitholders and Class B unitholders will receive cash. KMR will receive a distribution of 1,611,255 additional i-units based on the $1.11 distribution per common unit. For each outstanding i-unit that KMR holds, a fraction of an i-unit (0.017844) will be issued. This fraction was determined by dividing:

- $1.11, the cash amount distributed per common unit

by

- $62.207, the average of KMR's shares' closing market prices from October 13-26, 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.

Our declared distribution for the third quarter of 2010 of $1.11 per unit will result in incentive distributions to our general partner of $266.7 million. Under the terms of our partnership agreement, our declared distributions to unitholders for the third quarter of 2010 required incentive distributions to our general partner in the amount of $272.5 million; however, our general partner agreed to waive an incentive amount equal to $5.8 million related to equity issued to finance our acquisition of a 50% interest in Petrohawk Energy Corporation's natural gas gathering and treating business. Comparatively, our distribution of $1.05 per unit paid on November 13, 2009 for the third quarter of 2009 resulted in incentive distribution payments to our general partner of $235.0 million.

6. Risk Management

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

Energy Commodity Price Risk Management

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

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

For derivative contracts that are designated and qualify as cash flow hedges pursuant to 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. During the three and nine months ended September 30, 2010, we recognized net losses of $9.5 million and net gains of $4.6 million, respectively, related to crude oil and natural gas hedges and resulting from both hedge ineffectiveness and amounts excluded from effectiveness testing. During the three and nine months ended September 30, 2009, we recognized a net hedging loss of $5.4 million from crude oil hedges that resulted from hedge ineffectiveness and amounts excluded from effectiveness testing.

Additionally, during the three and nine months ended September 30, 2010, we reclassified losses of $47.6 million and $134.6 million, respectively, from "Accumulated other comprehensive loss" into earnings, and for the same comparable periods last year, we reclassified losses of $21.0 million and $34.3 million, respectively, into earnings. No material amounts were reclassified into earnings as a result of the discontinuance of cash flow hedges because it was probable that the original forecasted transactions would no longer occur by the end of the originally specified time period or within an additional two-month period of time thereafter, but rather, were reclassified as a result of the hedged forecasted transactions actually affecting earnings (i.e., when the forecasted sales and purchase actually occurred). The proceeds or payments resulting from the settlement of our cash flow hedges are reflected in the operating section of our statement of cash flows as changes to net income and working capital.

The "Accumulated other comprehensive loss" balance included in our Partners' Capital was $144.2 million as of September 30, 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 $201.5 million as of September 30, 2010 and $418.2 million as of December 31, 2009. Approximately $153.7 million of the total loss amount associated with energy commodity price risk management activities and included in our Partners' Capital as of September 30, 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 September 30, 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 September 30, 2010, we had entered into the following outstanding commodity forward contracts to hedge our forecasted energy commodity purchases and sales:

	Net open position long/(short)
Derivatives designated as hedging contracts	
Crude oil	(22.0) million barrels
Natural gas fixed price	(32.7) billion cubic feet
Natural gas basis	(22.3) billion cubic feet
Derivatives not designated as hedging contracts	
Natural gas basis	(0.2) billion cubic feet

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

Interest Rate Risk Management

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

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

As of 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. In the second quarter of 2010, we entered into three additional fixed-to-variable interest rate swap agreements having a combined notional principal amount of $400 million. Each agreement effectively converts a portion of the interest expense associated with our 5.30% senior notes due September 15, 2020 from a fixed rate to a variable rate based on an interest rate of LIBOR plus a spread.

Accordingly, as of September 30, 2010, we had a combined notional principal amount of $5.6 billion of fixed-to-variable interest rate swap agreements. All of our swap agreements have termination dates that correspond to the maturity dates of the related series of senior notes and, as of September 30, 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 September 30, 2010 and December 31, 2009 (in millions):

Fair Value of Derivative Contracts

		Asset derivatives		Liability derivatives	
		September 30, 2010	December 31, 2009	September 30, 2010	December 31, 2009
	Balance sheet location	Fair value	Fair value	Fair value	Fair value
Derivatives designated as hedging contracts					
Energy commodity derivative contracts	Current	$ 41.2	$ 19.1	$ (202.5)	$ (270.8)
	Non-current	60.9	57.3	(108.2)	(241.5)
Subtotal		102.1	76.4	(310.7)	(512.3)
Interest rate swap agreements	Non-current	654.9	222.5	(16.9)	(218.6)
Total		757.0	298.9	(327.6)	(730.9)
Derivatives not designated as hedging contracts					
Energy commodity derivative contracts	Current	8.8	1.7	(10.6)	(1.2)
Total		8.8	1.7	(10.6	(1.2)
Total derivatives		$ 765.8	$ 300.6	$ (338.2)	$ (732.1)

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 September 30, 2010 and December 31, 2009, this unamortized premium totaled $314.7 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 and nine months ended September 30, 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)			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2010	2009	2010	2009
Interest rate swap agreements	Interest, net - income/(expense)	$ 219.9	$ 108.5	$ 634.1	$ (361.3)
Total		$ 219.9	$ 108.5	$ 634.1	$ (361.3)

Hedged items in fair value hedging relationships	Location of gain/(loss) recognized in income on related hedged item	Amount of gain/(loss) recognized in income on related hedged item(a)			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2010	2009	2010	2009
Fixed rate debt	Interest, net - income/(expense)	$ (219.9)	$ (108.5)	$ (634.1)	$ 361.3
Total		$ (219.9)	$ (108.5)	$ (634.1)	$ 361.3

(a) Amounts reflect the change in the fair value of interest rate swap agreements and the change in the fair value of the associated fixed rate debt which exactly offset each other as a result of no hedge ineffectiveness. Amounts do not reflect the impact on interest expense from the interest rate swap agreements under which we pay variable rate interest and receive fixed rate interest.

Derivatives in cash flow hedging relationships	Amount of gain/(loss) recognized in OCI on derivative (effective portion)		Location of gain/(loss) recognized from Accumulated OCI into income (effective portion)	Amount of gain/(loss) reclassified from Accumulated OCI into income (effective portion)		Location of gain/(loss) recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)	Amount of gain/(loss) recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)	
	Three Months Ended September 30,			Three Months Ended September 30,			Three Months Ended September 30,	
	2010	2009		2010	2009		2010	2009
Energy commodity derivative contracts	$ (83.3)	$ 35.0	Revenues–natural gas sales	$ 3.6	$ 4.8	Revenues–natural gas sales	$ -	$ -
			Revenues–product sales and other	(44.2)	(53.5)	Revenue–product sales and other	(7.9)	(5.4)
			Gas purchases and other costs of sales	(7.0)	27.7	Gas purchases and other costs of sales	(1.6)	-
Total	$ (83.3)	$ 35.0	Total	$ (47.6)	$ (21.0)	Total	$ (9.5)	$ (5.4)
	Nine Months Ended September 30,			Nine Months Ended September 30,			Nine Months Ended September 30,	
	2010	2009		2010	2009		2010	2009
Energy commodity derivative contracts	$ 84.4	$ (268.6)	Revenues–natural gas sales	$ 5.3	$ 11.3	Revenues–natural gas sales	$ -	$ -
			Revenue–product sales and other	(142.6)	(66.4)	Revenue–product sales and other	5.4	(5.4)
			Gas purchases and other costs of sales	2.7	20.8	Gas purchases and other costs of sales	(0.8)	-
Total	$ 84.4	$ (268.6)	Total	$ (134.6)	$ (34.3)	Total	$ 4.6	$ (5.4)

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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 September 30,		Nine Months Ended September 30,	
		2010	2009	2010	2009
Energy commodity derivative contracts	Gas purchases and other costs of sales	$ 0.2	$ (0.8)	$ 1.0	$ (3.1)
Total		$ 0.2	$ (0.8)	$ 1.0	$ (3.1)

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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 September 30, 2010 was (in millions):

	Asset position
Interest rate swap agreements	$ 654.9
Energy commodity derivative contracts	110.9
Gross exposure	765.8
Netting agreement impact	(79.9)
Net exposure	$ 685.9

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 September 30, 2010, we had no outstanding letters of credit supporting our hedging activities; however, as of December 31, 2009, we had outstanding letters of credit totaling $55.0 million 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 September 30, 2010, our counterparties associated with our energy commodity contract positions and over-the–counter swap agreements had margin deposits with us totaling $6.3 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 this amount 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 September 30, 2010, we estimate that if our credit rating was downgraded, we would have the following additional collateral obligations (in millions):

Credit ratings downgraded (a)	Incremental obligations	Cumulative obligations(b)
One notch to BBB-/Baa3	$ -	$ -
Two notches to below BBB-/Baa3 (below investment grade)	$ 73.8	$ 73.8

(a) If there are split ratings among the independent credit rating agencies, most counterparties use the higher credit rating to determine our incremental collateral obligations, while the remaining use the lower credit rating. Therefore, a two notch downgrade to below BBB-/Baa3 by one agency would not trigger the entire $73.8 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 September 30, 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 September 30, 2010				
Energy commodity derivative contracts(a)	$ 110.9	$ -	$ 50.2	$ 60.7
Interest rate swap agreements	$ 654.9	$ -	$ 654.9	$ -
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 September 30, 2010				
Energy commodity derivative contracts(b)	$ (321.3)	$ -	$ (295.2)	$ (26.1)
Interest rate swap agreements	$ (16.9)	$ -	$ (16.9)	$ -
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 natural gas basis swaps, West Texas Sour hedges, and West Texas Intermediate options.

The fair value measurements as of December 31, 2009 in the tables above do not include cash margin deposits, which are reported separately as "Restricted deposits" in our accompanying consolidated balance sheet. The table below provides a summary of changes in the fair value of our Level 3 energy commodity derivative contracts for each of the three and nine months ended September 30, 2010 and 2009 (in millions):

Significant unobservable inputs (Level 3)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	**2009**	**2010**	**2009**
Derivatives-net asset (liability)				
Beginning of Period	$ 46.6	$ 24.0	$ 13.0	$ 44.1
Realized and unrealized net gains and (losses)	(11.4)	2.7	15.3	(19.1)
Purchases and settlements	(0.6)	3.2	6.3	4.9
Transfers in (out) of Level 3	-	-	-	-
End of Period	$ 34.6	$ 29.9	$ 34.6	$ 29.9
Change in unrealized net gains (losses) relating to contracts still held at end of period	$ (12.2)	$ (0.1)	$ 8.3	$ (29.5)

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 September 30, 2010 and December 31, 2009 (both short-term and long-term, but excluding the value of interest rate swaps), is disclosed below (in millions):

	September 30, 2010		December 31, 2009	
	Carrying value	**Estimated fair value**	**Carrying value**	**Estimated fair value**
Total debt	$ 11,688.4	$ 13,004.5	$ 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;
- CO_2—the production and sale of crude oil from fields in the Permian Basin of West Texas and the transportation and marketing of carbon dioxide used as a flooding medium for recovering crude oil from mature oil fields;
- Terminals—the transloading and storing of refined petroleum products and dry and liquid bulk products, including coal, petroleum coke, cement, alumina, salt and other bulk chemicals; and
- Kinder Morgan Canada—the transportation of crude oil and refined products from Alberta, Canada to marketing terminals and refineries in British Columbia, the state of Washington and the Rocky Mountains and Central regions of the United States.

We evaluate performance principally based on each 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 September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Revenues				
Products Pipelines				
Revenues from external customers	$ 227.7	$ 216.7	$ 661.5	$ 611.6
Natural Gas Pipelines				
Revenues from external customers	1,147.6	838.8	3,414.0	2,751.2
CO_2				
Revenues from external customers	296.0	262.3	932.4	749.4
Terminals				
Revenues from external customers	321.2	282.8	945.3	814.2
Intersegment revenues	0.3	0.2	0.8	0.7
Kinder Morgan Canada				
Revenues from external customers	67.5	60.1	197.9	166.1
Total segment revenues	2,060.3	1,660.9	6,151.9	5,093.2
Less: Total intersegment revenues	(0.3)	(0.2)	(0.8)	(0.7)
Total consolidated revenues	$ 2,060.0	$ 1,660.7	$ 6,151.1	$ 5,092.5

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Segment earnings before depreciation, depletion, amortization and amortization of excess cost of equity investments(a)				
Products Pipelines(b)	$ 167.5	$ 167.9	$ 339.1	$ 468.3
Natural Gas Pipelines	187.3	197.8	592.9	560.7
CO_2	221.5	193.2	724.1	563.3
Terminals	159.2	155.2	475.2	432.8
Kinder Morgan Canada	44.0	47.7	132.9	113.9
Total segment earnings before DD&A	779.5	761.8	2,264.2	2,139.0
Total segment depreciation, depletion and amortization	(224.1)	(202.9)	(674.6)	(616.2)
Total segment amortization of excess cost of investments	(1.4)	(1.4)	(4.3)	(4.3)
General and administrative expenses	(93.6)	(83.7)	(288.1)	(238.8)
Unallocable interest expense, net of interest income	(133.8)	(107.8)	(373.9)	(313.7)
Unallocable income tax expense	(4.2)	(2.3)	(8.4)	(6.9)
Total consolidated net income	$ 322.4	$ 363.7	$ 914.9	$ 959.1

	September 30, 2010	December 31, 2009
Assets		
Products Pipelines	$ 4,323.8	$ 4,299.0
Natural Gas Pipelines	8,762.9	7,772.7
CO_2	2,136.3	2,224.5
Terminals	4,048.0	3,636.6
Kinder Morgan Canada	1,817.4	1,797.7
Total segment assets	21,088.4	19,730.5
Corporate assets(c)	964.2	531.7
Total consolidated assets	$ 22,052.6	$ 20,262.2

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

(b) Nine month 2010 amount includes a $158.0 million increase in expense associated with rate case liability adjustments. For more information on our rate case proceedings, see Note 10.

(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. We received a principal repayment amount of $1.3 million in June 2010. The outstanding note receivable balance was $83.5 million as of September 30, 2010 and $84.8 million as of December 31, 2009. We included $2.7 million and $2.6 million within "Accounts, notes and interest receivable, net," on our accompanying consolidated balance sheets as of September 30, 2010 and December 31, 2009, respectively, and the remaining outstanding balance 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 September 30, 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 $110.4 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 September 30, 2010 and December 31, 2009, our related party receivables (other than notes receivable discussed above in "—Notes Receivable") totaled $9.5 million and $13.8 million, respectively. The September 30, 2010 amount is included within "Accounts, notes and interest receivable, net" and primarily related to accounts and interest receivables due from Plantation Pipe Line Company, KinderHawk Field Services LLC and the Express pipeline system. 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 Natural Gas Pipeline Company of America LLC, a 20%-owned equity investee of KMI and referred to in this report as NGPL; and (ii) $3.1 million of natural gas imbalance receivables included within "Other current assets" and consisting primarily of amounts due from NGPL.

As of September 30, 2010 and December 31, 2009, our related party payables totaled $10.3 million and $13.4 million, respectively. The September 30, 2010 amount consisted of (i) $5.5 million included within "Accounts payable" and primarily related to amounts due to KMI; and (ii) $4.8 million of natural gas imbalance payables included within "Accrued other current liabilities" and consisting primarily of amounts due to NGPL. The December 31, 2009 related party payable amounts are included within "Accounts payable" on our accompanying balance sheet, and primarily consisted of amounts we owed to KMI.

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 September 30, 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.

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 September 30, 2010 and December 31, 2009 (in millions):

	September 30, 2010	December 31, 2009
Derivatives – asset/(liability)		
Current assets	$ -	$ 4.3
Noncurrent assets	$ 17.2	$ 18.4
Current liabilities	$ (131.3)	$ (96.8)
Noncurrent liabilities	$ (76.9)	$ (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 the owners of KMI. Accordingly, certain conflicts of interest could arise as a result of the relationships among KMR, our general partner, KMI and us.

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

For a more complete discussion of our related party transactions, including (i) the accounting for our general and administrative expenses; (ii) KMI's operation and maintenance of the assets comprising our Natural Gas Pipelines business segment; and (iii) our partnership interests and distributions, see Note 11 to our consolidated financial statements included in our 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 nine months ended September 30, 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 nine months ended September 30, 2010, and a description of any material events occurring subsequent to September 30, 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; 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; Valero Energy Corporation as Valero; Valero Marketing and Supply Company as Valero Marketing; Continental Airlines, Inc., Northwest Airlines, Inc., Southwest Airlines Co. and US Airways, Inc., collectively, as the Airlines; our subsidiary Kinder Morgan CO_2 Company, L.P. (the successor to Shell CO_2 Company, Ltd.) as Kinder Morgan CO_2; the United States Court of Appeals for the District of Columbia Circuit as the D.C. Circuit; the Federal Energy Regulatory Commission as the FERC; the California Public Utilities Commission as the CPUC; the 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 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

The tariffs and rates charged by SFPP and Calnev are subject to numerous ongoing proceedings at the FERC, including the shippers' complaints and protests regarding interstate rates on the pipeline systems listed below. These complaints and protests have been filed over numerous years beginning in 1992 through and including 2009. In general, these complaints and protests allege the rates and tariffs charged by SFPP are not just and reasonable. If the shippers are successful in proving their claims, they are entitled to seek reparations (which may reach up to two years prior to the filing of their complaints) or refunds of any excess rates paid, and SFPP may be required to reduce its rates going forward. These proceedings tend to be protracted, with decisions of the FERC often appealed to the federal courts.

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.

SFPP

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.

As a result of FERC's approval in May 2010 of a settlement agreement with eleven of twelve shippers, a wide range of rate challenges dating back to 1992 were resolved (Historical Cases Settlement). The Historical Cases Settlement resolves all but two of the cases outstanding between SFPP and the eleven shippers, and SFPP does not expect any material adverse impacts from the remaining two unsettled cases with the eleven shippers.

The Historical Cases Settlement and other legal reserves related to SFPP rate litigation resulted in a $158.0 million charge to earnings in the first quarter of 2010. From a cash perspective, a portion of our partnership distributions for the second quarter of 2010 (which we paid in August 2010) was a distribution of cash from interim capital transactions (ICT Distribution), rather than a distribution of cash from operations. As a result, our general partner's cash distributions for the second quarter of 2010 were reduced by $170.0 million. As provided in our partnership agreement, our general partner receives no incentive distribution on ICT Distributions; therefore, there was no practical impact to our limited partners from this ICT Distribution because (i) the expected cash distribution to the limited partners did not change; (ii) fewer dollars in the aggregate were distributed (because there were no incentive distributions paid to the general partner related to the portion of the quarterly distribution that was an ICT Distribution); and (iii) our general partner, in this instance, agreed to waive any resetting of the incentive distribution target levels, as would otherwise occur according to our partnership agreement.

We expect that our second quarter ICT Distribution will allow us to resolve our remaining FERC rate cases (discussed above) and CPUC rate cases (discussed below) without impacting future distributions, and 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. Furthermore, our declared cash distribution for the third quarter of 2010 of $1.11 per unit (which we will pay in November 2010) contains no ICT Distribution, but instead consists entirely of distributions of cash from operations.

Chevron is the only shipper who is not a party to the Historical Cases Settlement, and the following dockets remain pending only as to Chevron:

- FERC Docket Nos. OR92-8, et al. (West and East Line Rates)—Chevron protests of compliance filings pending with FERC and appeals pending at the D.C. Circuit;
- FERC Docket Nos. OR96-2, et al. (All SFPP Rates)—Chevron (as a successor-in-interest to Texaco) protests of compliance filings pending with FERC;
- FERC Docket No. OR02-4 (All SFPP Rates)—Chevron appeal of complaint dismissal pending at the D.C. Circuit;
- FERC Docket No. OR03-5 (West, East, North, and Oregon Line Rates)—Chevron exceptions to initial decision pending at FERC;
- FERC Docket No. OR07-4 (All SFPP Rates)—Chevron complaint held in abeyance;
- FERC Docket No. OR09-8 (consolidated) (2008 Index Increases)—Hearing regarding Chevron complaint held in abeyance pending settlement discussions;
- FERC Docket No. IS98-1 (Sepulveda Line Rates)—Chevron protests to compliance filing pending at FERC;
- FERC Docket No. IS05-230 (North Line Rates)—Chevron exceptions to initial decision pending at FERC;
- FERC Docket No. IS07-116 (Sepulveda Line Rates)—Chevron protest subject to resolution of IS98-1 proceeding;
- FERC Docket No. IS08-137 (West and East Line Rates)—Chevron protest subject to resolution of the OR92-8/OR96-2 proceeding;
- FERC Docket No. IS08-302 (2008 Index Rate Increases)—Chevron protest subject to the resolution of proceedings regarding the West, North and Sepulveda Lines; and
- FERC Docket No. IS09-375 (2009 Index Rate Increases)—Chevron protest subject to resolution of proceedings regarding the North, West and Sepulveda Lines.

The following dockets are pending as to all protesting shippers:

- FERC Docket No. IS08-390 (West Line Rates)—Protestants: BP, ExxonMobil, ConocoPhillips, Valero Marketing, Chevron, the Airlines—Status: Exceptions to initial decision pending at FERC; and
- FERC Docket No. IS09-437 (East Line Rates)—Protestants: BP, ExxonMobil, ConocoPhillips, Valero, Chevron, Western Refining, and Southwest Airlines—Status: Awaiting Initial Decision expected in January 2011.

Calnev

- FERC Docket Nos. OR07-7, OR07-18, OR07-19 & OR07-22 (not consolidated) (Calnev Rates)—Complainants: Tesoro, Airlines, BP, Chevron, ConocoPhillips and Valero Marketing—Status: Complaint amendments pending before FERC;
- FERC Docket No. IS09-377 (2009 Index Rate Increases)—Protestants: BP, Chevron, and Tesoro—Status: Requests for rehearing of FERC dismissal pending before FERC;
- FERC Docket Nos. OR09-11/OR09-14 (not consolidated) (2007 and 2008 Page 700 Audit Request)—Complainants: BP/Tesoro—Status: BP petition for review at D.C. Circuit dismissed, mandate issued in June 2010;
- FERC Docket Nos. OR09-15/OR09-20 (not consolidated) (Calnev Rates)—Complainants: Tesoro/BP—Status: Complaints pending at FERC; and
- FERC Docket Nos. OR09-18/OR09-22 (not consolidated) (2009 Index Increases)—Complainants: Tesoro/BP—Status: BP petition for review at D.C. Circuit dismissed, mandate issued.

Trailblazer Pipeline Company LLC

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

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 filed comments on May 3, 2010 outlining the errors in law and fact within the proposed decision and on May 5, 2010, SFPP made oral arguments before the full CPUC. The matter remains pending before the CPUC, which is expected to address the subject matters before the end of the year. 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, as discussed above.

Carbon Dioxide Litigation

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

Kinder Morgan CO_2, 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. The plaintiffs appealed to the United States Fifth Circuit Court of Appeals. On June 16, 2010, the Fifth Circuit Court of Appeals affirmed the trial court's summary judgment decision. Gerald Bailey subsequently filed a petition for writ of certiorari to the U.S. Supreme Court seeking further appellate review of the Fifth Circuit Court of Appeals' decision.

CO_2 Claims Arbitration

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

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

On October 2, 2007, the plaintiffs initiated a second arbitration (*CO_2 Committee, Inc. v. Shell CO_2 Company, Ltd., aka Kinder Morgan CO_2 Company, L.P., et al.*) against Cortez Pipeline Company, Kinder Morgan CO_2 and an ExxonMobil entity. The second arbitration asserts claims similar to those asserted in the first arbitration. A second arbitration panel has convened and a final hearing on the parties' claims and defenses is expected to occur in 2011.

MMS Notice of Noncompliance and Civil Penalty

On December 20, 2006, Kinder Morgan CO_2 received from the MMS a "Notice of Noncompliance and Civil Penalty: Knowing or Willful Submission of False, Inaccurate, or Misleading Information—Kinder Morgan CO_2 Company, L.P., case no. CP07-001." This Notice, and the MMS's position that Kinder Morgan CO_2 has violated certain reporting obligations, relates to a disagreement between the MMS and Kinder Morgan CO_2 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 assessed 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 CO_2's alleged submission of false, inaccurate, or misleading information relating to the transportation allowance, and federal royalties for CO_2 produced at McElmo Dome, during the period from June 2005 through October 2006. The MMS stated that civil penalties would continue to accrue at the same rate until the alleged violations are corrected.

On January 3, 2007, Kinder Morgan CO_2 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 CO_2 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 in principle of the Notice of Noncompliance and Civil Penalty, subject to final approval by the MMS and the Department of the Interior. On September 8, 2010, the United States Department of the Interior, Bureau of Ocean Energy Management, Regulation, and Enforcement (formerly known as the MMS) approved the settlement, which is now final.

MMS Orders to Report and Pay

On March 20, 2007, Kinder Morgan CO_2 received an Order to Report and Pay from the MMS. The MMS contends that Kinder Morgan CO_2 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 CO_2 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 CO_2'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 CO_2 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 CO_2 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 CO_2 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 in principle 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 September 8, 2010, the United States Department of the Interior, Bureau of Ocean Energy Management, Regulation, and Enforcement (formerly known as the MMS) approved the settlement, which is now final.

Colorado Severance Tax Assessment

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

Montezuma County, Colorado Property Tax Assessment

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

Other

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

Commercial Litigation Matters

Union Pacific Railroad Company Easements

SFPP and UPRR are engaged in a proceeding to determine the extent, if any, to which the rent payable by SFPP for the use of pipeline easements on rights-of-way held by UPRR should be adjusted pursuant to existing contractual arrangements for the ten year period beginning January 1, 2004 (*Union Pacific Railroad Company 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 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. On September 15, 2010, our subsidiary KM Ship Channel Services LLC, as owner of the *JR Nicholls*, agreed to pay a civil penalty of $7,500 for the unintentional discharge of diesel fuel which occurred when the vessel sank.

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.

Pasadena Terminal Fire

On September 23, 2008, a fire occurred in the pit 3 manifold area of our Pasadena, Texas liquids terminal facility. 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 in September 2008. We have reached an agreement with the TCEQ to settle this matter for $40,000. We expect that the settlement will be finalized prior to December 31, 2010.

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.

Rockies Express Pipeline LLC Indiana Construction Incident

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

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

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 September 30, 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 $157.9 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 both a $158.0 million increase in expense in the first quarter of 2010 associated with various rate case liability adjustments that increased our overall rate case liability, and a $206.3 million payment in the second quarter of 2010 that reduced the liability. 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 end of 2010. The judge has set a hearing for December 10, 2010 to rule on the stay. During the stay, the parties deemed responsible by the local regulatory agency have worked with that agency concerning the scope of the required cleanup. 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 was owned by Pacific Atlantic Terminals, LLC, and is now owned by Plains Products, and it too is a party to the lawsuit.

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

On June 25, 2007, the New Jersey Department of Environmental Protection, the Commissioner of the New Jersey Department of Environmental Protection and the Administrator of the New Jersey Spill Compensation Fund, referred to collectively as the plaintiffs, filed a complaint against ExxonMobil Corporation and 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/Plains seeking to bring Support Terminals/Plains into the case. Support Terminals/Plains filed motions to dismiss the third party complaints, which were denied. Support Terminals/Plains is now joined in the case, and it filed an Answer denying all claims. The court has consolidated the two cases.

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, 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 September 30, 2010, we have accrued an environmental reserve of $77.7 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 September 30, 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 nine months ended September 30, 2010. This note also contains a description of any material regulatory matters initiated during the nine months ended September 30, 2010 in which we are involved. In this note, we refer to the Federal Energy Regulatory Commission as the FERC.

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 was made available as of October 5, 2010. The total FERC authorized cost for the proposed project was 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. 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 service on the expanded storage project effective February 1, 2010. KMIGT commenced placing all remaining facilities into service on August 13, 2010.

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

KMIGT has filed a prior notice request to expand and replace certain mainline pipeline facilities to create up to 10,000 dekatherms per day of firm transportation capacity to serve an ethanol plant located near Aurora, Nebraska. The estimated cost of the proposed facilities is $18.9 million. On September 24, 2010 Seminole Energy Services, LLC filed a protest to the construction of this project, and the protest was subsequently denied by the FERC in an order issued October 15, 2010. KMIGT is proceeding with the construction of this project which is expected to be completed in December 2010.

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

Construction is nearly completed on our previously announced Fayetteville Express Pipeline project. The Fayetteville Express Pipeline is owned by Fayetteville Express Pipeline LLC, a 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 begins in Conway County, Arkansas, continues eastward through White County, Arkansas, and terminates 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 the pipeline's certificate application authorizing pipeline construction, and initial construction on the project began in January 2010. The pipeline began interim service on October 12, 2010, and is expected to be fully operational by December 1, 2010. We estimate that the total costs of this pipeline project will be slightly above $1.0 billion (versus the original budget of $1.3 billion and consistent with our October 20, 2010 third quarter earnings press release).

12. Recent Accounting Pronouncements

Accounting Standards Updates

None of the Accounting Standards Updates that we adopted and that became effective January 1, 2010 had 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.

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

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

With respect to our interstate natural gas pipelines and related storage facilities, the revenues from these assets tend to be received under contracts with terms that are fixed for various and extended periods of time. To the extent practicable and economically feasible in light of our strategic plans and other factors, we generally attempt to mitigate risk of reduced volumes and prices by negotiating contracts with longer terms, with higher per-unit pricing and for a greater percentage of our available capacity. These long-term contracts are typically structured with a fixed-fee reserving the right to transport natural gas and specify that we receive the majority of our fee for making the capacity available, whether or not the customer actually chooses to utilize the capacity. Therefore, where we have long-term contracts we are not exposed to short-term changes in commodity supply or demand. However, as contracts expire, we do have exposure to the longer term trends in supply and demand for natural gas. Currently, the remaining average contract life of our natural gas transportation contracts is in excess of eight years.

Our CO_2 sales and transportation business, like our natural gas pipelines business, generally has fixed fee contracts with minimum volume requirements. In the long-term, our success in this business is driven by the demand for carbon dioxide. However, short-term changes in the demand for carbon dioxide typically do not have a significant impact on us due to the required minimum transport volumes under many of our contracts. In the oil and gas producing activities within our CO_2 business segment, we monitor the amount of capital we expend in relation to the amount of production that we expect to add. In that regard, our production during any period is an important measure. In addition, the revenues we receive from our crude oil, natural gas liquids and carbon dioxide sales are affected by the prices we realize from the sale of these products. Over the long-term, we will tend to receive prices that are dictated by the demand and overall market price for these products. In the shorter term, however, market prices are likely not indicative of the revenues we will receive due to our risk management, or hedging, program, in which the prices to be realized for certain of our future sales quantities are fixed, capped or bracketed through the use of financial derivative contracts, particularly for crude oil.

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

In our discussions of the operating results of individual businesses that follow, we generally identify the important fluctuations between periods that are attributable to acquisitions and dispositions separately from those that are attributable to businesses owned in both periods. We believe that we have a history of making accretive acquisitions and economically advantageous expansions of existing businesses—since 1998, we have invested over $20 billion of capital for both strategic business acquisitions and expansions of existing assets. Our capital investments have helped us to achieve compound annual growth rates in cash distributions to our limited partners of 4.5%, 8.8%, and 7.9%, respectively, for the one-year, three-year, and five-year periods ended December 31, 2009.

Thus, the amount that we are able to increase distributions to our unitholders will, to some extent, be a function of our ability to complete successful acquisitions and expansions. We believe we will continue to have opportunities for expansion of our facilities in many markets, and we have budgeted approximately $1.5 billion for our 2010 capital expansion program, including for small acquisitions. Based on our historical record and because there is continued demand for energy infrastructure in the areas we serve, we expect to continue to have such opportunities in the future, although the level of such opportunities is difficult to predict.

Our ability to make accretive acquisitions is a function of the availability of suitable acquisition candidates at the right cost, and includes factors over which we have limited or no control. Thus, we have no way to determine the number or size of accretive acquisition candidates in the future, or whether we will complete the acquisition of any such candidates.

In addition, our ability to make accretive acquisitions or expand our assets is impacted by our ability to maintain adequate liquidity and to raise the necessary capital needed to fund such acquisitions. As a master limited partnership, we distribute all of our available cash and we access capital markets to fund acquisitions and asset expansions. Historically, we have succeeded in raising necessary capital in order to fund our acquisitions and expansions, often doing so during periods of notably tight financial conditions. For example, in December 2008, we raised a combined $675 million in cash from public debt and equity offerings. Although we cannot predict future changes in the overall equity and debt capital markets (in terms of tightening or loosening of credit), we believe that our stable cash flows, our investment grade credit rating, and our historical record of successfully accessing both equity and debt funding sources should allow us to continue to execute our current investment, distribution and acquisition strategies, as well as refinance maturing debt when required. For a further discussion of our liquidity, including our public debt and equity offerings in 2010, please see "—Financial Condition" below.

Critical Accounting Policies and Estimates

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

With regard to goodwill impairment testing, we review our goodwill for impairment annually, and we evaluated our goodwill for impairment on May 31, 2010. Our goodwill impairment analysis performed on that date did not result in an impairment charge, and no event indicating an impairment has occurred subsequent to that date. For more information on our goodwill impairment analysis, see Note 3 “Intangibles—Goodwill” to our consolidated financial statements included elsewhere in this report.

Further information about us and information regarding our accounting policies and estimates that we consider to be “critical” can be found in our 2009 Form 10-K. There have not been any significant changes in these policies and estimates during the nine months ended September 30, 2010.

Results of Operations

Consolidated

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Earnings increase/(decrease)	
	(In millions, except percentages)			
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments(a)				
Products Pipelines(b)	$ 167.5	$ 167.9	$ (0.4)	-
Natural Gas Pipelines(c)	187.3	197.8	(10.5)	(5)%
CO_2(d)	221.5	193.2	28.3	15 %
Terminals(e)	159.2	155.2	4.0	3 %
Kinder Morgan Canada	44.0	47.7	(3.7)	(8)%
Segment earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	779.5	761.8	17.7	2 %
Depreciation, depletion and amortization expense	(224.1)	(202.9)	(21.2)	(10)%
Amortization of excess cost of equity investments	(1.4)	(1.4)	-	-
General and administrative expense(f)	(93.6)	(83.7)	(9.9)	(12)%
Unallocable interest expense, net of interest income(g)	(133.8)	(107.8)	(26.0)	(24)%
Unallocable income tax expense	(4.2)	(2.3)	(1.9)	(83)%
Net income	322.4	363.7	(41.3)	(11)%
Net income attributable to noncontrolling interests(h)	(1.6)	(4.2)	2.6	62 %
Net income attributable to Kinder Morgan Energy Partners, L.P.	$ 320.8	$ 359.5	$ (38.7)	(11)%

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009	Earnings increase/(decrease)	
	(In millions, except percentages)			
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments(a)				
Products Pipelines(i)	$ 339.1	$ 468.3	$ (129.2)	(28)%
Natural Gas Pipelines(j)	592.9	560.7	32.2	6%
CO_2(k)	724.1	563.3	160.8	29%
Terminals(l)	475.2	432.8	42.4	10%
Kinder Morgan Canada(m)	132.9	113.9	19.0	17%
Segment earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	2,264.2	2,139.0	125.2	6%
Depreciation, depletion and amortization expense	(674.6)	(616.2)	(58.4)	(9)%
Amortization of excess cost of equity investments	(4.3)	(4.3)	-	-
General and administrative expense(n)	(288.1)	(238.8)	(49.3)	(21)%
Unallocable interest expense, net of interest income(o)	(373.9)	(313.7)	(60.2)	(19)%
Unallocable income tax expense	(8.4)	(6.9)	(1.5)	(22)%
Net income	914.9	959.1	(44.2)	(5)%
Net income attributable to noncontrolling interests(p)	(7.6)	(11.9)	4.3	36%
Net income attributable to Kinder Morgan Energy Partners, L.P.	$ 907.3	$ 947.2	$ (39.9)	(4)%

(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 $2.5 million increase in expense from environmental liability adjustments, and a $1.9 million increase in property environmental expense related to the retirement of our Gaffey Street, California land. 2009 amount includes a $0.1 million increase in income from hurricane casualty gains. 2010 and 2009 amounts also include increases in income of $0.3 million and $1.1 million, respectively, resulting from unrealized foreign currency gains and losses on long-term debt transactions.

(c) 2010 amount includes a $1.6 million unrealized loss on derivative contracts used to hedge forecasted natural gas sales. 2009 amount includes a $3.7 million increase in income from hurricane casualty gains, and a $0.7 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 and 2009 amounts include unrealized losses of $7.9 million and $5.4 million, respectively, on derivative contracts used to hedge forecasted crude oil sales.

(e) 2010 amount includes a $5.0 million increase in expense from casualty insurance deductibles, and a $0.2 million decrease in expense from certain measurement period adjustments related to our March 5, 2010 Slay Industries terminal acquisition. 2009 amount includes an $11.2 million increase in income from fire and hurricane casualty gains.

(f) Includes unallocated litigation and environmental expenses. 2010 and 2009 amounts include (i) increases in expense of $1.0 million and $1.5 million, respectively, from non-cash compensation expense allocated to us from KMI (we do not have any obligation, nor do we expect to pay any amounts related to these expenses), and (ii) increases in expense of $1.1 million and $0.5 million, respectively, for certain asset and business acquisition costs that would have been capitalized under prior accounting standards. 2009 amount also includes a $0.9 million decrease in expense related to capitalized overhead costs associated with the 2008 hurricane season.

(g) 2010 and 2009 amounts include increases in imputed interest expense of $0.2 million and $0.4 million, respectively, related to our January 1, 2007 Cochin Pipeline acquisition.

(h) 2010 and 2009 amounts include a $1.9 million decrease and a $0.1 million increase, respectively, in net income attributable to our noncontrolling interests, related to the effect from all of the three month 2010 items previously disclosed in these footnotes.

(i) 2010 amount includes a $158.0 million increase in expense associated with rate case liability adjustments, and a $17.4 million decrease in income associated with combined property environmental expenses and the demolition of physical assets in preparation for the sale of our Gaffey Street, California land. 2009 amount includes a $0.1 million increase in income from hurricane casualty gains. 2010 and 2009 amounts also include (i) increases in expense of $2.5 million and $3.8 million, respectively, associated with environmental liability adjustments; and (ii) increases in income of $0.4 million and $1.5 million, respectively, resulting from unrealized foreign currency gains and losses on long-term debt transactions.

(j) 2010 amount includes a $0.8 million unrealized loss 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 $4.5 million decrease in income resulting from unrealized mark to market gains and losses due to the discontinuance of hedge accounting at Casper Douglas, and a $3.7 million increase in income from hurricane casualty gains.

(k) 2010 and 2009 amounts include a $5.4 million unrealized gain and a $5.4 million unrealized loss, respectively, on derivative contracts used to hedge forecasted crude oil sales.

(l) 2010 amount includes (i) a $6.7 million casualty indemnification gain related to a 2008 fire at our Pasadena, Texas liquids terminals; (ii) a $0.2 million decrease in expense from certain measurement period adjustments related to our March 5, 2010 Slay Industries terminal acquisition; (iii) a $5.0 million increase in expense from casualty insurance deductibles; and (iv) a $0.6 million increase in expense related to storm and flood clean-up and repair activities. 2009 amount includes (i) an $11.2 million increase in income from fire and hurricane casualty gains; (ii) a $0.5 million decrease in expense associated with legal liability adjustments related to a litigation matter involving our Staten Island liquids terminal; and (iii) a $0.1 million increase in expense associated with environmental liability adjustments.

(m) 2009 amount includes a $14.9 million increase in expense primarily due to certain non-cash regulatory accounting adjustments to the carrying amount of Trans Mountain pipeline system's previously established deferred tax liability, and a $3.7 million decrease in expense due to a certain non-cash accounting adjustment related to book tax accruals made by the Express pipeline system.

(n) Includes unallocated litigation and environmental expenses. 2010 and 2009 amounts include (i) increases in expense of $3.7 million and $4.3 million, respectively, from non-cash compensation expense allocated to us from KMI (we do not have any obligation, nor do we expect to pay any amounts related to these expenses); (ii) increases in expense of $3.5 million and $0.6 million, respectively, for certain asset and business acquisition costs; and (iii) decreases in expense of $0.2 million and $2.4 million, respectively, related to capitalized overhead costs associated with the 2008 hurricane season. 2010 amount also includes a $1.6 million increase in legal expense associated with items disclosed in these footnotes such as legal settlements and pipeline failures.

(o) 2010 and 2009 amounts include increases in imputed interest expense of $0.8 million and $1.2 million, respectively, related to our January 1, 2007 Cochin Pipeline acquisition.

(p) 2010 and 2009 amounts include decreases of $4.3 million and $0.1 million, respectively, in net income attributable to our noncontrolling interests, related to all of the nine month 2010 and 2009 items previously disclosed in these footnotes.

Net income attributable to our partners—including all of our limited partner unitholders and our general partner—totaled $320.8 million for the three months ended September 30, 2010. This compares to net income attributable to our partners of $359.5 million for the third quarter of 2009. For the nine months ended September 30, 2010 and 2009, net income attributable to our partners totaled $907.3 million and $947.2 million, respectively. We earned total revenues of $2,060.0 million and $1,660.7 million, respectively, in the three month periods ended September 30, 2010 and 2009, and revenues of $6,151.1 million and $5,092.5 million, respectively, in the nine month periods ended September 30, 2010 and 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.

Compared to the third quarter of 2009, total segment earnings before depreciation, depletion and amortization increased $17.7 million (2%) in the third quarter of 2010. The overall increase included a $28.4 million decrease in earnings from the effect of the certain items described in the footnotes to the tables above (which combined to decrease total segment EBDA by $18.4 million in the third quarter of 2010 and increase total segment EBDA by $10.0 million in the third quarter of 2009). The remaining $46.1 million (6%) increase in quarterly segment earnings before depreciation, depletion and amortization included higher earnings in 2010 from our CO_2, Terminals, and Products Pipelines business segments, partially offset with lower earnings from our Natural Gas Pipelines and Kinder Morgan Canada business segments.

For the comparable nine month periods, total segment earnings before depreciation, depletion and amortization increased $125.2 million (6%) in 2010; however, the overall increase included a decrease in earnings of $163.2 million from the combined effect of the certain items described in the footnotes to the tables above (combining to decrease total segment EBDA by $171.2 million and $8.0 million in the first nine months of 2010 and 2009, respectively). The remaining $288.4 million (13%) increase in total segment earnings before depreciation, depletion and amortization in the first nine months of 2010 versus the first nine months of 2009 resulted from better performance from all five of our reportable business segments, mainly due to increases attributable to our CO_2, Terminals, and Products Pipelines business segments.

Products Pipelines

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(In millions, except operating statistics)			
Revenues	$ 227.7	$ 216.7	$ 661.5	$ 611.6
Operating expenses(a)	(67.8)	(56.8)	(341.7)	(165.8)
Other income (expense)(b)	(0.1)	0.1	(4.0)	0.1
Earnings from equity investments	7.6	6.5	22.2	19.9
Interest income and Other, net-income(c)	2.1	3.5	6.0	9.8
Income tax expense	(2.0)	(2.1)	(4.9)	(7.3)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 167.5	$ 167.9	$ 339.1	$ 468.3
Gasoline (MMBbl)(d)	102.2	101.4	299.4	301.2
Diesel fuel (MMBbl)	38.4	35.9	109.5	107.9
Jet fuel (MMBbl)	27.1	28.8	78.1	83.7
Total refined product volumes (MMBbl)	167.7	166.1	487.0	492.8
Natural gas liquids (MMBbl)	6.7	6.2	18.3	18.4
Total delivery volumes (MMBbl)(e)	174.4	172.3	505.3	511.2
Ethanol (MMBbl)(f)	7.6	6.1	22.4	16.7

(a) Three and nine month 2010 amounts include increases in expense of $2.5 million from environmental liability adjustments, and increases in expense of $1.9 million and $13.5 million, respectively, associated with environmental clean-up expenses and the demolition of physical assets in preparation for the sale of our of our Gaffey Street, California land. Nine month 2010 amount also includes a $158.0 million increase in expense associated with rate case liability adjustments. Nine month 2009 amount includes a $3.8 million increase in expense associated with environmental liability adjustments.

(b) Nine month 2010 amount includes disposal losses of $3.9 million related to the retirement of our Gaffey Street, California land. Three and nine month 2009 amounts represent gains from hurricane casualty indemnifications.

(c) Three and nine month 2010 amounts include increases in income of $0.3 million and $0.4 million, respectively, and three and nine month 2009 amounts include increases in income of $1.1 million and $1.5 million, respectively, all resulting from unrealized foreign currency gains and losses on long-term debt transactions.

(d) Volumes include ethanol pipeline volumes.

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

(f) Represents total ethanol volumes, including ethanol pipeline volumes.

For the three and nine months ended September 30, 2010, the certain items described in the footnotes to the table above decreased earnings before depreciation, depletion and amortization expenses by $5.3 million and $175.3 million, respectively, when compared to the same periods of 2009. Following is information for each of the comparable three and nine month periods of 2010 and 2009 related to the segment’s (i) remaining $4.9 million (3%) and $46.1 million (10%)

increases in earnings before depreciation, depletion and amortization; and (ii) $11.0 million (5%) and $49.9 million (8%) increases in operating revenues:

Three months ended September 30, 2010 versus Three months ended September 30, 2009

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Pacific operations	$ 8.4	12 %	$ 12.4	12 %
West Coast Terminals	2.7	16 %	3.5	15 %
Cochin Pipeline	1.3	15 %	1.2	10 %
Transmix operations	(6.0)	(39)%	(6.2)	(34)%
Central Florida Pipeline	(0.9)	(7)%	0.4	2 %
Southeast Terminals	(0.8)	(5)%	(0.5)	(2)%
All others (including intrasegment eliminations)	0.2	1 %	0.2	1 %
Total Products Pipelines	$ 4.9	3 %	$ 11.0	5 %

Nine months ended September 30, 2010 versus Nine months ended September 30, 2009

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Pacific operations	$ 31.5	16 %	$ 38.0	13 %
Southeast Terminals	11.4	29 %	10.3	18 %
West Coast Terminals	7.4	15 %	7.3	11 %
Central Florida Pipeline	3.2	8 %	1.9	4 %
Cochin Pipeline	(10.8)	(31)%	(6.7)	(17)%
Transmix operations	(1.6)	(6)%	(4.7)	(12)%
All others (including intrasegment eliminations)	5.0	7 %	3.8	5 %
Total Products Pipelines	$ 46.1	10 %	$ 49.9	8 %

The increases in our Products Pipelines business segment's earnings before depreciation, depletion and amortization expenses in both the third quarter and first nine months of 2010, when compared to the same two periods a year ago, were driven by higher earnings from our Pacific operations. The earnings increases were largely revenue related, due to increases of $7.8 million (11%) and $25.8 million (12%), respectively, in mainline delivery revenues, and increases of $4.6 million (18%) and $12.2 million (16%), respectively, in fee-based terminal revenues. The increases in pipeline delivery revenues year to date were attributable to higher average tariff rates in 2010 (due in part to FERC-approved rate increases), military tender rate increases, and for the comparable three month periods, to an overall 1% increase in mainline delivery volumes. The increases in terminal revenues were mainly attributable to incremental ethanol handling services that were due in part to mandated increases in ethanol blending rates in California since the end of the third quarter of 2009.

Other period-to-period increases and decreases in segment earnings before depreciation, depletion and amortization in the comparable three and nine month periods of 2010 and 2009 included the following:

- increases of $2.7 million (16%) and $7.4 million (15%), respectively, from our West Coast terminal operations. The increases were driven by higher warehousing revenues and incremental customers at our combined Carson/Los Angeles Harbor terminal system, incremental biodiesel revenues from our liquids facilities located in Portland, Oregon, and incremental earnings contributions from the terminals' Portland, Oregon Airport pipeline, which was acquired on July 31, 2009;

- an increase of $1.3 million (15%) and a decrease of $10.8 million (31%), respectively, from our Cochin pipeline system. The quarterly increase was chiefly due to a 5% increase in total pipeline throughput volumes in the third quarter of 2010 versus the same prior year quarter. For the comparable nine month periods, the decrease in earnings was primarily attributable to a 23% decline in system delivery volumes in 2010, due in part to the negative impacts from unfavorable tariff changes in 2010;

- decreases of $6.0 million (39%) and $1.6 million (6%), respectively, from our Transmix processing operations. The lower period-to-period earnings were mainly due to a combined $8.0 million increase in revenues recognized in August 2009. At that time, we recorded certain true-ups related to transmix settlement gains (including tank gains and incremental loss allowance gains);

- a decrease of $0.9 million (7%) and an increase of $3.2 million (8%), respectively, from our Central Florida Pipeline. Earnings remained essentially flat across both quarterly periods, but for the comparable nine months, earnings increased in 2010 due to both incremental product inventory gains and higher ethanol handling revenues; and

- a decrease of $0.8 million (5%) and an increase of $11.4 million (29%), respectively, from our Southeast terminal operations. Earnings were flat across both quarterly periods, but for the comparable nine months, earnings increased in 2010 due to both increased ethanol throughput and higher product inventory sales at higher prices.

For all segment assets combined, ethanol volumes handled increased 25% in the third quarter of 2010, and increased 34% in the first nine months of 2010, when compared to the same periods last year. 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.

Natural Gas Pipelines

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	**2009**	**2010**	**2009**
	(In millions, except operating statistics)			
Revenues(a)	$ 1,147.6	$ 838.8	$ 3,414.0	$ 2,751.2
Operating expenses(b)	(1,001.8)	(696.1)	(2,938.1)	(2,325.9)
Other income(c)	-	3.7	-	3.7
Earnings from equity investments	42.0	48.7	115.9	104.7
Interest income and Other, net-income	0.6	3.8	2.9	31.1
Income tax expense	(1.1)	(1.1)	(1.8)	(4.1)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 187.3	$ 197.8	$ 592.9	$ 560.7
Natural gas transport volumes (Bcf)(d)	652.5	633.3	1,920.8	1,683.6
Natural gas sales volumes (Bcf)(e)	214.1	200.5	602.1	602.3

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

(b) Three and nine month 2010 amounts include unrealized losses of $1.6 million and $0.8 million, respectively, on derivative contracts used to hedge forecasted natural gas sales. Three and nine month 2009 amounts include decreases in income of $0.7 million and $4.5 million, respectively, 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) Three and nine month 2009 amounts represent gains from hurricane casualty indemnifications.

(d) 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.

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

For the three and nine months ended September 30, 2010, the certain items described in the footnotes to the table above decreased earnings before depreciation, depletion and amortization expenses by $4.6 million and increased earnings before depreciation, depletion and amortization expenses by $0.4 million, respectively, when compared to the same periods of 2009, and also increased revenues in the first nine months of 2010 by $0.4 million, when compared to the first nine months of 2009. Following is information for each of the comparable three and nine month periods of 2010 and 2009, related to the segment's (i) remaining $5.9 million (3%) decrease and $31.8 million (6%) increase in earnings before depreciation, depletion and amortization; and (ii) $308.8 million (37%) and remaining $662.4 million (24%) increases in operating revenues:

Three months ended September 30, 2010 versus Three months ended September 30, 2009

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Kinder Morgan Natural Gas Treating	$ 10.9	n/a	$ 15.7	n/a
Kinder Morgan Louisiana Pipeline	5.7	62 %	8.4	100 %
KinderHawk Field Services(a)	5.1	n/a	-	-
Midcontinent Express Pipeline(a)	1.1	16 %	-	-
Texas Intrastate Natural Gas Pipeline Group	(14.7)	(17)%	270.5	36 %
Rockies Express Pipeline(a)	(14.3)	(41)%	-	-
Kinder Morgan Interstate Gas Transmission	(2.3)	(9)%	9.4	22 %
All others (including intrasegment eliminations)	2.6	8 %	4.8	10 %
Total Natural Gas Pipelines	$ (5.9)	(3)%	$ 308.8	37 %

Nine months ended September 30, 2010 versus Nine months ended September 30, 2009

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Kinder Morgan Natural Gas Treating	$ 32.0	n/a	$ 46.1	n/a
Kinder Morgan Louisiana Pipeline	13.8	49 %	42.4	501 %
Midcontinent Express Pipeline(a)	13.2	172 %	-	-
KinderHawk Field Services(a)	6.8	n/a	-	-
Texas Intrastate Natural Gas Pipeline Group	(20.8)	(8)%	544.7	22 %
Rockies Express Pipeline(a)	(12.1)	(16)%	-	-
Kinder Morgan Interstate Gas Transmission	(9.2)	(10)%	3.6	3 %
All others (including intrasegment eliminations)	8.1	8 %	25.6	19 %
Total Natural Gas Pipelines	$ 31.8	6 %	$ 662.4	24 %

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

Increases in our Natural Gas Pipelines segment's earnings before depreciation, depletion and amortization expenses in the third quarter and first nine months of 2010 versus the same periods of 2009 were driven by incremental contributions from our Kinder Morgan Natural Gas Treating operations and our Kinder Morgan Louisiana natural gas pipeline system.

Our Kinder Morgan Louisiana pipeline system began full transportation service on June 21, 2009, and we acquired the majority of our Kinder Morgan Natural Gas Treating operations from CrossTex Energy, Inc. on October 1, 2009, and we acquired the remaining portion from Gas-Chill, Inc. on September 1, 2010. Combined, these assets contributed incremental earnings before depreciation, depletion and amortization of $10.9 million, revenues of $15.7 million and operating expenses of $4.8 million in the third quarter of 2010, and incremental earnings before depreciation, depletion and amortization of $32.0 million, revenues of $46.1 million and operating expenses of $14.1 million in the first nine months of 2010.

Other period-to-period increases and decreases in segment earnings before depreciation, depletion and amortization in the comparable three and nine month periods of 2010 and 2009 included the following:

- increases of $5.1 million and $6.8 million, respectively, due to incremental equity earnings from our 50%-owned KinderHawk Field Services LLC. We acquired our 50% ownership interest on May 21, 2010. KinderHawk's assets consist of more than 300 miles of pipeline currently in service, with projected throughput of approximately 800 million cubic feet per day of natural gas by the end of 2010. Additionally, the system's natural gas amine treating plants have a current capacity of approximately 2,135 gallons per minute.

  KinderHawk has also received a dedication to transport and treat all of Petrohawk Energy Corporation's operated Haynesville and Bossier shale gas production in northwest 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 transportation services to third-party producers;

- increases of $1.1 million (16%) and $13.2 million (172%), respectively, due to incremental equity earnings from our 50%-owned Midcontinent Express natural gas pipeline system. The incremental earnings from our investment in Midcontinent Express were driven by the commencement and/or expansion of natural gas transportation service since the end of the third quarter of 2009. The Midcontinent Express system initiated interim natural gas transportation service for its Zone 1 on April 10, 2009, achieved full Zone 1 service on May 21, 2009, and achieved full Zone 2 service on August 1, 2009. In addition, in June 2010, Midcontinent Express completed two natural gas compression projects that increased Zone 1 capacity from 1.5 to 1.8 billion cubic feet per day, and Zone 2 capacity from 1.0 to 1.2 billion cubic feet per day. The incremental capacity is fully subscribed with ten-year binding shipper agreements;

- decreases of $14.7 million (17%) and $20.8 million (8%), respectively, from our Texas intrastate natural gas pipeline group. The overall decreases in earnings were driven by (i) decreases of $9.9 million and $13.0 million, respectively, from overall storage activities (primarily due to lower price spreads relative to 2009); and (ii) decreases of $2.5 million and $4.1 million, respectively, due to lower natural gas gains. For the comparable nine month periods, the overall decrease in earnings also included (i) a $6.0 million decrease in natural gas sales margins, largely attributable to higher costs of natural gas supplies relative to sales price; (ii) a $3.5 million decrease from lower interest income, due to a one-time natural gas loan to a single customer in 2009; and (iii) a $7.6 million increase in natural gas processing margins, due mainly to higher natural gas liquids prices relative to 2009;

- decreases of $14.3 million (41%) and $12.1 million (16%), respectively, from our 50%-owned Rockies Express pipeline system, primarily due to lower net income earned by Rockies Express Pipeline LLC in the third quarter of 2010. The quarter to quarter decrease in Rockies Express' 100% net income was mainly due to (i) a $14.2 million increase in interest expenses, due to the debt mix shifting to longer term maturities; (ii) a $14.1 million increase in depreciation and amortization expenses, due to a higher depreciable asset base; and (iii) a $26.6 million increase in property tax expenses, including an $11.7 million increase associated with a higher than expected assessment in the state of Ohio.

  Partially offsetting the decreases in earnings described above were increases in earnings (primarily from incremental natural gas transportation revenues) in both the third quarter and first nine months of 2010 related to the completion and start-up of the Rockies Express-East pipeline segment, which began initial pipeline service on June 29, 2009, and began full operations on November 12, 2009. Our operating results for the first nine months of 2010 were also negatively impacted, however, by a portion of the 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, and full service was restored on February 6, 2010. The shutdown cost us approximately $15 million in demand charge credits in the first quarter of 2010; and

- decreases of $2.3 million (9%) and $9.2 million (10%), respectively, from our Kinder Morgan Interstate Gas Transmission pipeline system—due largely to lower margins on operational sales of natural gas (due mainly to lower average natural gas prices in 2010), lower pipeline net fuel recoveries, and lower earnings from short-term natural gas balancing services.

The overall changes in both segment revenues and segment operating expenses (which include natural gas costs of sales) in the comparable three and nine month periods of 2010 and 2009 primarily relate to the natural gas purchase and sale activities of our Texas 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 intrastate group both purchases and sells significant volumes of natural gas, which is often stored and/or transported on its pipelines, and because the group generally sells natural gas in the same price environment in which it is purchased, the increases and decreases in its gas sales revenues are largely offset by corresponding increases and decreases in its gas purchase costs. Our intrastate group accounted for 88% of the segment's total revenues and 94% of the segment's total operating expenses in each of the third quarters of 2010 and 2009, respectively. For the comparable nine month periods of 2010 and 2009, the intrastate group accounted for 89% and 90%, respectively, of total revenues, and 95% and 96%, respectively, of total segment operating expenses.

CO_2

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(In millions, except operating statistics)			
Revenues(a)	$ 296.0	$ 262.3	$ 932.4	$ 749.4
Operating expenses	(78.2)	(72.5)	(229.9)	(198.4)
Earnings from equity investments	4.7	5.5	17.7	16.4
Interest income and Other, net-income (expense)	-	(1.2)	1.9	(1.2)
Income tax benefit (expense)	(1.0)	(0.9)	2.0	(2.9)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 221.5	$ 193.2	$ 724.1	$ 563.3
Carbon dioxide delivery volumes (Bcf)(b)	175.6	178.3	558.2	579.7
SACROC oil production (gross)(MBbl/d)(c)	29.0	29.6	29.4	30.2
SACROC oil production (net)(MBbl/d)(d)	24.2	24.7	24.5	25.2
Yates oil production (gross)(MBbl/d)(c)	23.2	26.4	24.4	26.6
Yates oil production (net)(MBbl/d)(d)	10.3	11.7	10.8	11.8
Natural gas liquids sales volumes (net)(MBbl/d)(d)	10.0	9.5	9.9	9.3
Realized weighted average oil price per Bbl(e)(f)	$ 59.54	$ 51.42	$ 59.88	$ 48.27
Realized weighted average natural gas liquids price per Bbl(f)(g)	$ 46.73	$ 40.28	$ 50.06	$ 34.31

(a) Three and nine month 2010 amounts include unrealized losses (from decreases in revenues) of $7.9 million and unrealized gains (from increases in revenues) of $5.4 million, respectively, on derivative contracts used to hedge forecasted crude oil sales. Three and nine month 2009 amounts include unrealized losses (from decreases in revenues) of $5.4 million 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 CO_2 segment's primary businesses involve the production, marketing and transportation of both carbon dioxide (commonly called CO_2) and crude oil, and the production and marketing of natural gas and natural gas liquids. We refer to the segment's two primary businesses as its Oil and Gas Producing Activities and Sales and Transportation Activities.

For the three and nine months ended September 30, 2010, the unrealized gains and losses on derivative contracts used to hedge forecasted crude oil sales described in footnote (a) to the table above decreased both earnings before depreciation, depletion and amortization expenses and revenues by $2.5 million and increased both earnings before depreciation, depletion and amortization expenses and revenues by $10.8 million, respectively, when compared to the same two periods of 2009. For each of the segment's two primary businesses, following is information for each of the comparable three and nine month periods of 2010 and 2009, related to the segment's (i) remaining $30.8 million (16%) and $150.0 million (26%) increases in earnings before depreciation, depletion and amortization; and (ii) remaining $36.2 million (14%) and $172.2 million (23%) increases in operating revenues:

Three months ended September 30, 2010 versus Three months ended September 30, 2009

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Oil and Gas Producing Activities	$ 19.7	13 %	$ 26.5	12 %
Sales and Transportation Activities	11.1	22 %	12.0	20 %
Intrasegment eliminations	-	-	(2.3)	(22)%
Total CO_2	$ 30.8	16 %	$ 36.2	14 %

Nine months ended September 30, 2010 versus Nine months ended September 30, 2009

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Oil and Gas Producing Activities	$ 115.0	28 %	$ 145.9	24 %
Sales and Transportation Activities	35.0	22 %	31.6	17 %
Intrasegment eliminations	-	-	(5.3)	(16)%
Total CO_2	$ 150.0	26 %	$ 172.2	23 %

The segment's overall period-to-period increases in earnings before depreciation, depletion and amortization expenses were primarily due to higher earnings from its oil and gas producing activities, which include the operations associated with our ownership interests in oil-producing fields and natural gas processing plants. The increases in earnings from oil and gas producing activities in the three and nine month periods ended September 30, 2010 compared to the three and nine month periods ended September 30, 2009 were mainly due to the following:

- increases of $24.6 million (12%) and $138.4 million (24%), respectively, in combined crude oil and natural gas plant products sales revenues, due largely to increases of 16% and 24%, respectively, in our realized weighted average price per barrel of crude oil, and increases of 16% and 46%, respectively, in our realized weighted average price per barrel of natural gas liquids. We also benefitted from increases in natural gas liquids sales volumes of 5% in the third quarter of 2010 and 6% in the first nine months of 2010, when compared to the same periods a year ago. Overall operating revenues were somewhat offset by a decrease in crude oil sales volumes of 5% in both the third quarter and first nine months of 2010;

- increases of $1.9 million (24%) and $7.5 million (38%), respectively, in other revenues, driven by higher net profits interest revenues in 2010 from our 28% net profits interest in the Snyder, Texas natural gas processing plant, due to higher natural gas liquid production; and

- decreases of $6.8 million (9%) and $32.8 million (17%), respectively, due to higher operating expenses, driven by (i) increases in tax expenses, other than income tax expenses, resulting primarily from reductions in severance tax expense in the first nine months of 2009 related to prior year overpayments; and (ii) for the comparable nine month periods, higher operating and maintenance expenses resulting from increased natural gas processing volumes in 2010.

The overall period-to-period increases in earnings from the segment's sales and transportation activities were mainly due to increases of $10.6 million (26%) and $31.4 million (25%), respectively, in carbon dioxide sales revenues. The period-to-period increases in sales revenues were primarily price related, and for the comparable nine month periods, partly volume related. The segment's average price received for all carbon dioxide sales in the third quarter and first nine months of 2010 increased 27% and 25%, respectively, reflecting continuing strong demand for carbon dioxide's oil recovery use in mature oil fields. Overall carbon dioxide sales volumes were essentially flat across both quarterly periods, but increased 1% in the first nine months of 2010 versus the same prior year period.

Terminals

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(In millions, except operating statistics)			
Revenues	$ 321.5	$ 283.0	$ 946.1	$ 814.9
Operating expenses(a)	(163.7)	(137.6)	(480.3)	(395.1)
Other income (expense)(b)	(0.1)	10.7	10.4	14.3
Earnings from equity investments	0.7	0.2	1.3	0.3
Interest income and Other, net-income	2.8	1.3	3.2	2.4
Income tax expense(c)	(2.0)	(2.4)	(5.5)	(4.0)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 159.2	$ 155.2	$ 475.2	$ 432.8
Bulk transload tonnage (MMtons)(d)	24.4	22.8	71.0	61.8
Ethanol (MMBbl)	14.1	8.1	44.1	24.7
Liquids leaseable capacity (MMBbl)	58.2	55.6	58.2	55.6
Liquids utilization %	96.2 %	96.7 %	96.2 %	96.7 %

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(a) Three and nine month 2010 amounts include a $5.0 million increase in expense from casualty insurance deductibles and a $0.2 million decrease in expense from certain measurement period adjustments related to our March 5, 2010 Slay Industries terminal acquisition. Nine month 2010 amount also includes a $0.6 million increase in expense related to storm and flood clean-up and repair activities. Nine month 2009 amounts include a $0.5 million decrease in expense associated with legal liability adjustments related to a litigation matter involving our Staten Island liquids terminal, and a $0.1 million increase in expense associated with environmental liability adjustments.

(b) Nine month 2010 amount includes a $6.7 million casualty indemnification gain related to a 2008 fire at our Pasadena, Texas liquids terminal. Three and nine month 2009 amounts include gains of $11.3 million from hurricane and fire casualty indemnifications.

(c) Three and nine month 2009 amounts include a $0.1 million increase in expense related to hurricane casualty gains.

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

Our Terminals business segment includes the operations of our petroleum, chemical and other liquids terminal facilities (other than those included in our Products Pipelines segment), and all of our coal, petroleum coke, fertilizer, steel, ores and other dry-bulk material services facilities. 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.

In addition to the $0.2 million decrease in expense from certain measurement period adjustments related to our March 5, 2010 Slay Industries terminal acquisition described in footnote (a) to the table above, our acquired terminal operations accounted for incremental amounts of earnings before depreciation, depletion and amortization of $8.3 million, revenues of $15.7 million, operating expenses of $7.3 million, and equity earning losses of $0.1 million in the third quarter of 2010. For the first nine months of 2010, acquired assets contributed incremental earnings before depreciation, depletion and amortization of $23.1 million, revenues of $47.4 million, operating expenses of $24.2 million, and equity earning losses of $0.1 million.

All of the incremental amounts listed above represent the earnings, revenues and expenses from acquired terminals' operations during the additional months of ownership in 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 nine months of 2010, see Note 2 "Acquisitions, Joint Ventures, and Divestitures—Acquisitions" to our consolidated financial statements included elsewhere in this report.

For all other terminal operations (those owned during identical periods in both 2010 and 2009), the certain items described in the footnotes to the table accounted for decreases in earnings before depreciation, depletion and amortization of $16.2 million in the third quarter of 2010 and $10.5 million in the first nine months of 2010, when compared to the same two periods last year. Following is information for these terminal operations, for each of the comparable three and nine month periods and by terminal operating region, related to (i) the remaining $11.7 million (8%) and $29.6 million (7%) increases in earnings before depreciation, depletion and amortization; and (ii) the $22.8 million (8%) and $83.8 million (10%) increases in operating revenues:

Three months ended September 30, 2010 versus Three months ended September 30, 2009

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Gulf Coast	$ 8.1	22 %	$ 7.7	16 %
West	1.9	13 %	4.3	18 %
Texas Petcoke	1.4	8 %	3.1	8 %
Mid River	0.7	14 %	3.6	22 %
Ohio Valley	0.3	5 %	2.0	13 %
Southeast	0.3	3 %	1.1	4 %
Lower River (Louisiana)	0.1	-	3.4	15 %
Midwest	(0.9)	(7)%	0.5	2 %
All others (including intrasegment eliminations and unallocated income tax expenses)	(0.2)	-	(2.9)	(4)%
Total Terminals	$ 11.7	8 %	$ 22.8	8 %

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Nine months ended September 30, 2010 versus Nine months ended September 30, 2009

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
West	$ 12.4	36 %	$ 26.0	43 %
Gulf Coast	12.0	11 %	14.1	10 %
Mid River	6.4	50 %	19.2	47 %
Southeast	4.8	15 %	9.7	14 %
Ohio Valley	3.3	26 %	8.5	20 %
Lower River (Louisiana)	(2.9)	(8)%	6.5	9 %
Midwest	(2.1)	(6)%	1.9	3 %
Texas Petcoke	(2.0)	(4)%	2.8	3 %
All others (including intrasegment eliminations and unallocated income tax expenses)	(2.3)	(2)%	(4.9)	(2)%
Total Terminals	$ 29.6	7 %	$ 83.8	10 %

The earnings increases from our Gulf Coast terminals were 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 third quarter of 2009. For all liquids terminals combined, both our terminal acquisitions and our terminal expansion projects completed since the end of the third quarter last year increased our liquids terminals' leasable capacity by 2.6 million barrels (4.7%).

The increases in earnings from our West region terminals were driven by higher period-to-period earnings from our Canadian and Washington State terminals due to increased agricultural product volumes, favorable currency impacts from a strengthening of the Canadian dollar since the end of the third quarter last year, and higher rate tonnage in both the third quarter and first nine months of 2010.

Compared to the same periods last year, earnings from our Texas Petcoke operations increased in the third quarter of 2010, due primarily to higher revenues from incremental stevedoring and railcar services, and decreased in the first nine months of 2010, due primarily to both lower average rates per ton of petroleum coke moved and lower margins from our sulfur handling operations (total petroleum coke volumes were flat across both nine month periods). The lower rates resulted largely from a decline in Producer Price Index escalators in certain key customer contracts.

Earnings from our Mid-River, Ohio Valley, and Southeast terminals, which are located in the Central and Southeast regions of the U.S., increased across both three and nine month periods in 2010, due largely to increased steel volumes from rebounding steel consumption consistent with the ongoing economic recovery. For our Terminals segment combined, bulk traffic tonnage increased by 1.6 million tons (7%) in the third quarter of 2010 and by 9.2 million tons (15%) in the first nine months of 2010, when compared with the same prior year periods.

For the first nine months of 2010, earnings from both our Lower River (Louisiana) and Midwest terminal operations decreased versus the same period of 2009. The decrease in earnings from our Lower River terminals was primarily due to a property casualty gain recognized in the second quarter of 2009 on a vessel dock that was damaged in 2008. The decrease in earnings from our Midwest terminals was largely due to a 14% drop in coal transfer volumes at our Cora, Illinois terminal.

Kinder Morgan Canada

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(In millions, except operating statistics)			
Revenues	$ 67.5	$ 60.1	$ 197.9	$ 166.1
Operating expenses	(23.6)	(19.1)	(66.8)	(52.4)
Earnings from equity investments	(1.3)	(1.1)	(1.5)	(1.4)
Interest income and Other, net-income	4.7	10.3	12.3	19.2
Income tax expense(a)	(3.3)	(2.5)	(9.0)	(17.6)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 44.0	$ 47.7	$ 132.9	$ 113.9
Transport volumes (MMBbl)(b)	27.2	28.1	79.3	75.0

(a) Nine month 2009 amount includes both 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, and a $3.7 million decrease in expense due to a certain non-cash accounting adjustment related to book tax accruals made by the Express pipeline system.

(b) Represents Trans Mountain pipeline system volumes.

Our Kinder Morgan Canada business segment includes the operations of our Trans Mountain and Jet Fuel pipeline systems, and our one-third equity ownership interest in the Express pipeline system. As described in footnote (a) to the table above, the segment's overall increase in earnings before depreciation, depletion and amortization expenses in the nine months ended September 30, 2010, compared to the same period of 2009, included an increase of $11.2 million related to certain non-cash regulatory adjustments to income tax expense recorded in the first nine months of 2009.

Following is information, for each of the comparable three and nine month periods of 2010 and 2009, related to the segment's (i) $3.7 million (8%) decrease and remaining $7.8 million (6%) increase in earnings before depreciation, depletion and amortization, respectively; and (ii) $7.4 million (12%) and $31.8 million (19%) increases in operating revenues:

Three months ended September 30, 2010 versus Three months ended September 30, 2009

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Trans Mountain Pipeline	$ (2.7)	(6)%	$ 7.0	12 %
Jet Fuel Pipeline	(0.6)	(34)%	0.4	43 %
Express Pipeline	(0.4)	(18)%	-	-
Total Kinder Morgan Canada	$ (3.7)	(8)%	$ 7.4	12 %

Nine months ended September 30, 2010 versus Nine months ended September 30, 2009

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Trans Mountain Pipeline	$ 7.4	6 %	$ 30.0	18 %
Express Pipeline	0.9	12 %	-	-
Jet Fuel Pipeline	(0.5)	(15)%	1.8	70 %
Total Kinder Morgan Canada	$ 7.8	6 %	$ 31.8	19 %

The decline in earnings before depreciation, depletion and amortization in the third quarter of 2010 compared to the third quarter last year reflects changes in the Canadian to U.S. dollar exchange rate. While the Canadian dollar did strengthen during the third quarter of 2010, the impact was not as favorable as in the third quarter of 2009. For the comparable nine month periods of 2010 and 2009, the segment's increase in earnings in 2010 was driven by both favorable currency impacts from a strengthening of the Canadian dollar and increased volumes moving across our Trans Mountain tanker dock in Vancouver harbor.

Other

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	(In millions)			
General and administrative expenses(a)	$ 93.6	$ 83.7	$ 288.1	$ 238.8
Unallocable interest expense, net of interest income(b)	$ 133.8	$ 107.8	$ 373.9	$ 313.7
Unallocable income tax expense	$ 4.2	$ 2.3	$ 8.4	$ 6.9
Net income attributable to noncontrolling interests(c)	$ 1.6	$ 4.2	$ 7.6	$ 11.9

(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. Three and nine month 2010 amounts include (i) increases in expense of $1.0 million and $3.7 million, respectively, from non-cash compensation expense allocated to us from KMI (we do not have any obligation, nor do we expect to pay any amounts related to these expenses); and (ii) increases in expense of $1.1 million and $3.5 million, respectively, for certain asset and business acquisition costs. Nine month 2010 amount also includes an increase in legal expense of $1.6 million associated with certain items such as legal settlements and pipeline failures, and a decrease in expense of $0.2 million related to capitalized overhead costs associated with the 2008 hurricane season. Three and nine month 2009 amounts include (i) increases in expense of $1.5 million and $4.3 million, respectively, from non-cash compensation expense allocated to us from KMI (we do not have any obligation, nor do we expect to pay any amounts related to these expenses); (ii) increases in expense of $0.5 million and $0.6 million, respectively, for certain asset and business acquisition costs that were capitalized under prior accounting standards; and (iii) decreases in expense of $0.9 million and $2.4 million, respectively, from capitalized overhead costs associated with the 2008 hurricane season.

(b) Three and nine month 2010 amounts include increases in imputed interest expense of $0.2 million and $0.8 million, respectively, and three and nine month 2009 amounts include increases in imputed interest expense of $0.4 million and $1.2 million, respectively, all related to our January 1, 2007 Cochin Pipeline acquisition.

(c) Three and nine month 2010 amounts include decreases of $1.9 million and $4.3 million, respectively, in net income attributable to our noncontrolling interests, and the three and nine month 2009 amounts include an increase of $0.1 million and a decrease of $0.1 million, respectively, in net income attributable to our noncontrolling interests, all related to the combined effect of the three and nine month 2010 and 2009 items previously disclosed in the footnotes to the tables included above in "—Results of Operations."

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

For the three and nine months ended September 30, 2010, the certain items described in footnote (a) to the table above increased our general and administrative expenses by $1.0 million and $6.1 million, respectively, when compared with the same periods last year. The remaining $8.9 million (11%) quarter-to-quarter increase in expenses included increases of $4.9 million from higher employee benefit and payroll tax expenses and $2.0 million from higher legal expenses. For the comparable nine month periods, the remaining $43.2 million (18%) period-to-period increase in expenses included increases of (i) $17.4 million from higher employee benefit and payroll tax expenses; (ii) $8.0 million from higher overall corporate insurance expenses; (iii) $4.7 million from lower capitalization of overhead expenses (other than benefits and payroll taxes); and (iv) $4.1 million from higher legal expenses.

The increases in benefit and payroll tax expenses were 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 increases in insurance expenses were primarily due to higher expense accruals in 2010, related to year-over-year increases in commercial property and liability insurance costs, and partly due to incremental premium taxes. The drops in capitalized expenses were due to lower capital spending in the first nine months of 2010, relative to the first nine months of 2009, and the increases in legal expenses were primarily due to higher outside legal services in 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 items described in footnote (b) to the table above, our unallocable interest expense increased $26.2 million (24%) in the third quarter of 2010 and $60.6 million (19%) in the first nine months of 2010, when compared to the same periods a year earlier. The quarterly increase in interest expense in 2010 was mainly attributable to a higher average debt balance and partly attributable to a slight (1.5%) increase in our weighted average interest rate, when compared to the third quarter of 2009. Average borrowings for the three and nine month periods ended September 30, 2010 increased 19% and 17%, respectively, when compared to the same periods a year ago, largely due to the capital expenditures, business acquisitions, and joint venture contributions we have made since the end of the third quarter of 2009.

For the comparable nine month periods, the overall increase in interest expense was partially offset by lower effective interest rates in 2010 versus 2009. Due to a general drop in variable interest rates since the end of the third quarter of 2009, the weighted average interest rate on all of our borrowings decreased almost 7% in the first nine months of 2010, when compared to the same prior year period.

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 September 30, 2010, approximately 52% of our $11,688.4 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

As of September 30, 2010, we had $191.6 million of cash and cash equivalents. We provide for additional liquidity by maintaining a sizable amount of excess borrowing capacity related to our committed $2.0 billion senior unsecured revolving bank credit facility. After reduction for (i) our letters of credit; and (ii) borrowings under our commercial paper program, the remaining available borrowing capacity under our credit facility was $1,363.1 million as of September 30, 2010. We believe our cash position and our remaining borrowing capacity allow us to manage our day-to-day cash requirements and any anticipated obligations.

Additionally, we have consistently generated strong cash flow from operations (discussed below in "—Operating Activities"), generating $1,527.3 million and $1,377.0 million in cash from operations in the first nine months of 2010 and 2009, respectively, and we continue to have substantial flexibility in the equity market, as demonstrated by the issuance of an additional 3,066,323 common units from equity sales in the third quarter of 2010. We received net proceeds of $203.4 million for the issuance of these common units.

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.

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 some access to the commercial paper market that was not available prior to this rating change. Therefore, we expect that our short-term liquidity needs will be met through borrowings made under our bank credit facility and our commercial paper program. Nevertheless, our ability to satisfy our financing requirements or fund our planned capital expenditures will depend upon our future operating performance, which will be affected by prevailing economic conditions in the energy and terminals industries and other financial and business factors, some of which are beyond our control.

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

Short-term Liquidity

Our principal sources of short-term liquidity are our (i) $2.0 billion senior unsecured revolving bank credit facility that matures June 23, 2013; and (ii) cash from operations. 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 $2.3 billion. We provide for additional liquidity by maintaining a sizable amount of excess borrowing capacity related to our bank credit facility (discussed above in "—General") and currently, we believe our liquidity to be adequate.

Our outstanding short-term debt as of September 30, 2010 was $1,409.8 million, primarily consisting of (i) $700.0 million in principal amount of 6.75% senior notes that mature March 15, 2011; (ii) $414.8 million of commercial paper borrowings; and (iii) $250.0 million in principal amount of 7.50% senior notes that mature November 1, 2010. We intend to refinance our current short-term debt and any additional short-term debt incurred during the remainder of the year through a combination of long-term debt, equity, and either the issuance of additional commercial paper or additional bank credit facility borrowings to replace maturing commercial paper and bank credit facility borrowings and current maturities of long-term debt.

We had working capital deficits (current assets minus current liabilities) of $1,505.0 million as of September 30, 2010 and $772.9 million as of December 31, 2009. The unfavorable change from year-end 2009 was primarily due to $700.0 million in principal amount of 6.75% senior notes due March 15, 2011 being re-classified from long-term to short-term debt. 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 of cash from operations 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. For more information on our 2010 equity issuances, see Note 5 "Partners' Capital—Equity Issuances" to our consolidated financial statements included elsewhere in this report.

From time to time we issue long-term debt securities, often referred to as our senior notes. All of our senior notes issued to date, other than those issued by our subsidiaries and operating partnerships, generally have very similar terms, except for interest rates, maturity dates and prepayment premiums. For more information on our 2010 debt related transactions, including our issuances of senior notes, see Note 4 "Debt" to our consolidated financial statements included elsewhere in this report.

As of September 30, 2010 and December 31, 2009, the net carrying value of the various series of our senior notes was $11,126.1 million and $10,125.3 million, respectively, and the total liability balance due on the various borrowings of our operating partnerships and subsidiaries was $147.5 million and $167.1 million, respectively. To date, our debt balances have not adversely affected our operations, our ability to grow or our ability to repay or refinance our indebtedness. Based on our historical record, we believe that our capital structure will continue to allow us to achieve our business objectives. For additional information regarding our debt securities, see Note 8 "Debt" to our consolidated financial statements included in our 2009 Form 10-K.

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

Capital Structure

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

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

Capital Expenditures

Our sustaining capital expenditures—defined as capital expenditures which do not increase the capacity of an asset—totaled $120.9 million in the first nine months of 2010, compared to $112.0 million for the first nine months of 2009. These sustaining expenditure amounts include $0.1 million in the first nine months of 2010 and $0.2 million in the first nine months of 2009, for our proportionate share of the sustaining capital expenditures of (i) Rockies Express Pipeline LLC; (ii) Midcontinent Express Pipeline LLC; and (iii) for 2010 only, KinderHawk Field Services LLC. Additionally, our forecasted expenditures for the remaining three months of 2010 for sustaining capital expenditures are approximately $60.7 million, including less than $0.1 million for our proportionate shares of Rockies Express, Midcontinent Express, and KinderHawk Field Services.

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, both 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 member owners. We have no contingent debt obligation with respect to Rockies Express Pipeline LLC, and for information on our contingent debt obligation with respect to Midcontinent Express Pipeline LLC, see Note 4 "Debt—Contingent Debt" to our consolidated financial statements included elsewhere in this report.

Similarly, KinderHawk Field Services can fund its cash requirements for expansion capital expenditures with cash generated from its own operations, through borrowings under its own credit facility, or with proceeds from contributions received from its two member owners. Its $200 million three-year, revolving bank credit facility (due in May 2013) is nonrecourse to its member owners.

All of our capital expenditures, with the exception of sustaining capital expenditures, are classified as discretionary. Our discretionary capital expenditures totaled $601.3 million in the first nine months of 2010 and $963.6 million in the first nine months of 2009. The period-to-period decrease in discretionary capital expenditures was mainly due to higher capital expenditures made during the first nine months of 2009 on both major natural gas pipeline projects and expansions and improvements within our Terminals and Products Pipelines business segments. Generally, we fund our discretionary capital expenditures and our investment contributions through borrowings under our bank credit facility or our commercial paper program. To the extent these sources of funding are not sufficient, we generally fund additional amounts through the issuance of long-term notes or common units for cash.

Capital Requirements for Recent Transactions

In the first nine months of 2010, our cash outlays for the acquisitions of assets and equity investments totaled $1,172.8 million. With the exception of our acquisition of terminal assets from US Development Group LLC, which was partially acquired by the issuance of additional common units, we utilized our commercial paper program to fund these acquisitions and then reduced our short-term borrowings with the proceeds from our 2010 equity issuances and our May 2010 issuance of long-term senior notes.

Operating Activities

Net cash provided by operating activities was $1,527.3 million for the nine months ended September 30, 2010, versus $1,377.0 million in the same comparable period of 2009. The period-to-period increase of $150.3 million (11%) in cash flow from operations primarily consisted of:

- a $276.5 million increase in cash relative to net changes in working capital items, primarily due to (i) a $203.4 million increase in cash from the collection and payment of trade and related party receivables and payables (including collections and payments on natural gas transportation and exchange imbalance receivables and payables), due primarily to the timing of invoices received from customers and paid to vendors and suppliers; (ii) a $45.8 million increase in cash from higher payments in the first nine months of 2009 for natural gas storage on our Kinder Morgan Texas Pipeline system; (iii) a $27.5 million increase in cash from higher payments in the first nine months of 2009 for the settlement of certain refined products imbalance liabilities owed to U.S. military customers of our Products Pipelines business segment; and (iv) a $68.8 million decrease in cash due to higher interest payments (net of interest collections) in 2010, due to higher average borrowings (partially offset by lower average interest rates) relative to the first nine months a year ago;

- a $190.1 million increase in cash from overall higher partnership income from our five reportable business segments—after adjusting for the following five non-cash items: (i) depreciation, depletion and amortization expenses (including amortization of excess cost of equity investments); (ii) undistributed earnings from equity investees; (iii) income from the allowance for equity funds used during construction; (iv) income from the sale or casualty 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 in the first nine months of 2010 versus the first nine months of 2009 is discussed above in "—Results of Operations" (including all of the certain items disclosed in the associated table footnotes);

- a $190.8 million decrease in cash attributable to higher payments made in 2010 for transportation rate settlements, refunds and reparations made pursuant to certain legal settlements reached with various shippers on our Pacific operations' refined products pipelines. In May 2010, we paid $206.3 million to eleven of twelve shippers regarding the settlement of various transportation rate challenges filed with the Federal Energy Regulatory Commission (FERC) dating back as early as 1992. In May 2009, we made refund and settlement payments totaling $15.5 million to various shippers in connection with certain East Line rate settlement agreements; 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.

Investing Activities

Net cash used for investing activities was $1,908.3 million in the nine month period ended September 30, 2010, compared to $2,616.5 million in the comparable 2009 period. The $708.2 million (27%) period-to-period increase in cash was due to lower cash expended for investing activities during 2010, primarily attributable to:

- a $1,409.3 million increase in cash due to lower contributions to equity investees. We contributed $209.8 million to our equity investees in the first nine months of 2010, versus $1,619.1 million in the same comparable period a year ago. In the first nine months of 2009, we contributed a combined $1,610.3 million to Rockies Express Pipeline LLC, Midcontinent Express Pipeline LLC, and Fayetteville Express Pipeline LLC to partially fund our respective share of Rockies Express, Midcontinent Express, and Fayetteville Express pipeline system construction and/or pre-construction costs;

- a $353.3 million increase in cash due to lower capital expenditures—largely due to the higher investment undertaken in the first nine months of 2009 to construct our Kinder Morgan Louisiana Pipeline and to expand and improve our Terminals business segment;

- a $153.2 million increase in cash due to capital distributions (distributions in excess of cumulative earnings) received in the first nine months of 2010, primarily related to capital distributions received from Rockies Express Pipeline LLC and Midcontinent Express Pipeline LLC. Current accounting practice requires us to classify and report cumulative cash distributions in excess of cumulative equity earnings as a return of capital; however, this change in classification does not impact our cash available for distribution;

- a $34.9 million increase in cash due to lower period-to-period payments for margin and restricted deposits associated with energy commodity cash flow hedging activities in the first nine months of 2010;

- a $1,145.3 million decrease in cash due to higher acquisitions of assets and investments in the first nine months of 2010. In 2010, our cash outlays for strategic business acquisitions totaled $1,172.8 million, primarily consisting of (i) $921.4 million for a 50% equity ownership interest in Petrohawk Energy Corporation's natural gas gathering and treating business; (ii) $114.3 million for three unit train ethanol handling terminals acquired from US Development Group LLC in January 2010; and (iii) $97.0 million for terminal assets and investments acquired from Slay Industries in March 2010. Each of these 2010 acquisitions is discussed further in Note 2 "Acquisitions, Joint Ventures, and Divestitures" to our consolidated financial statements included elsewhere in this report. In the first nine months of 2009, our cash payments for acquired assets totaled $27.5 million, including $18.0 million for the acquisition of certain marine vessels from Megafleet Towing Co., Inc.; and

- a $109.6 million decrease in cash due to the full repayment received in the first nine months of 2009 of a loan we made in December 2008 to a single customer of our Texas intrastate natural gas pipeline group.

Financing Activities

Net cash provided by financing activities amounted to $425.0 million for the first nine months of 2010. For the same comparable period last year, our financing activities provided net cash of $1,340.8 million. The $915.8 million (68%) overall decrease in cash from the comparable 2009 period was mainly due to:

- a $754.7 million period-to-period decrease in cash from overall debt financing activities—which include our issuances and payments of debt and our debt issuance costs. The decrease in cash from overall financing activities was primarily due to a $737.6 million decrease in cash from changes in senior notes outstanding. In May 2010, we received $993.1 million, after underwriting discounts and commissions, from the issuance of an aggregate $1 billion in principal amount of senior notes in two separate series (discussed in Note 4 "Debt—Senior Notes" to our consolidated financial statements included elsewhere in this report), and in the first nine months of 2009, we received a combined $1,730.7 million from both issuing and repaying senior notes.

  In 2009, we both repaid $250 million of senior notes that matured on February 1, 2009, and completed offerings for an aggregate $2.0 billion in principal amount of senior notes. We used the proceeds from our long-term offerings of senior notes in both 2010 and 2009 to reduce the borrowings under both our commercial paper program and our bank credit facility;

- a $178.9 million decrease in cash from lower partnership equity issuances. The decrease relates to the $636.6 million we received, after commissions and underwriting expenses, from the sales of additional common units in the first nine months of 2010 (discussed in Note 5 "Partners' Capital—Equity Issuances" to our consolidated financial statements included elsewhere in this report), versus the $815.5 million we received in the first nine months of 2009.

  We used the proceeds from our 2010 equity issuances to reduce the borrowings under both our commercial paper program and our bank credit facility, and in 2009, to reduce the borrowings under our bank credit facility; and

- a $13.1 million increase in cash due to lower partnership distributions in the first nine months of 2010, when compared to the same period last year. Distributions to all partners, consisting of our common and Class B unitholders, our general partner and noncontrolling interests, totaled $1,299.4 million in the first nine months of 2010, versus $1,312.5 million in the first nine months a year ago. Further information regarding our distributions is discussed following in "—Partnership Distributions."

Partnership Distributions

Our partnership agreement requires that we distribute 100% of "Available Cash," as defined in our partnership agreement, to our partners within 45 days following the end of each calendar quarter 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 August 13, 2010, we paid a quarterly distribution of $1.09 per unit for the second quarter of 2010. This distribution was 4% greater than the $1.05 distribution per unit we paid in August 2009 for the second quarter of 2009. 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 $1.09 cash distribution per common unit. The incentive distribution that we paid on August 13, 2010 to our general partner (for the second quarter of 2010) totaled $89.8 million, and the incentive distribution that we paid in August 2009 (for the second quarter of 2009) totaled $231.8 million.

Because a portion of our available cash distribution for the second quarter of 2010 was a distribution of cash from interim capital transactions, rather than a distribution of cash from operations, our general partner was not entitled to an incentive distribution of $168.3 million that it would have received if all available cash distributions for the quarter would have consisted of cash from operations. In addition, our general partner waived an incentive distribution amount of $5.3 million, related to equity issued to finance our acquisition of a 50% interest in Petrohawk Energy Corporation's natural gas gathering and treating business. As provided in our partnership agreement, our general partner receives no incentive distribution on distributions of cash from interim capital transactions. Furthermore, pursuant to the provisions of our partnership agreement, in the event of a distribution of cash from interim capital transactions, our incentive distribution target levels should be adjusted proportionately lower (in order for our general partner to receive increased future incentive distributions); however, our general partner waived this right of adjustment. Including its effective 2% general partner interest in us, total cash distributions to our general partner for the second quarter of 2010 were reduced by $170.0 million.

On October 20, 2010, we declared a cash distribution of $1.11 per unit for the third quarter of 2010 (an annualized rate of $4.44 per unit). This distribution was 6% higher than the $1.05 per unit distribution we made for the third quarter of 2009. Under the terms of our partnership agreement, our declared distribution to unitholders for the third quarter of 2010 (which will be paid in the fourth quarter of 2010) required an incentive distribution to our general partner in the amount of $272.5 million; however, our general partner agreed to waive an incentive amount equal to $5.8 million related to equity issued to finance our acquisition of a 50% interest in Petrohawk Energy Corporation's natural gas gathering and treating business. Accordingly, our general partner's incentive distribution for the distribution we declared for the third quarter of 2010 is $266.7 million, and for the distribution we paid for the third quarter of 2009, our general partner's incentive distribution was $235.0 million.

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. Due to our general partner's support (described above), we do not expect the $4.40 per unit distribution to our limited partners for 2010 to be impacted by (i) any settlement payment we made or may be required to make for reparations sought by shippers on our West Coast Products Pipelines; or (ii) any general partner incentive distribution or related equity issued to finance the acquisition of our ownership interest in Petrohawk Energy Corporation's natural gas gathering and treating business.

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 $79 per barrel in 2010. Although the majority of the cash generated by our assets is fee based and is not sensitive to commodity prices, our CO_2 business segment is exposed to commodity price risk related to the price volatility of crude oil and natural gas liquids, and while we hedge the majority of our crude oil production, we do have exposure on our unhedged volumes, the majority of which are natural gas liquids volumes. For 2010, we expect that every $1 change in the average WTI crude oil price per barrel will impact our CO_2 segment's cash flows by approximately $6 million (or 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.

Off Balance Sheet Arrangements

Except as set forth with respect to contingent debt agreements with Rockies Express Pipeline LLC under "—Contingent Debt" in Note 4 "Debt" to our consolidated financial statements included elsewhere in this report, there have been no material changes in our obligations with respect to other entities that are not consolidated in our financial statements that would affect the disclosures presented as of December 31, 2009 in our 2009 Form 10-K.

Recent Accounting Pronouncements

Please refer to Note 12 “Recent Accounting Pronouncements” to our consolidated financial statements included elsewhere in this report for information concerning recent accounting pronouncements.

Information Regarding Forward-Looking Statements

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

- price trends and overall demand for natural gas liquids, refined petroleum products, oil, carbon dioxide, natural gas, electricity, coal, steel and other bulk materials and chemicals in North America;
- economic activity, weather, alternative energy sources, conservation and technological advances that may affect price trends and demand;
- changes in our tariff rates implemented by the Federal Energy Regulatory Commission 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, and Part II, Item 1A "Risk Factors" of this report 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 "Risk Management" to our consolidated financial statements included elsewhere in this report.

Item 4. Controls and Procedures.

As of September 30, 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 September 30, 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.

Except as set forth below, there have been no material changes in or additions to the risk factors disclosed in Item 1A "Risk Factors" in our 2009 Form 10-K.

New regulations or restrictions on drilling in the Gulf of Mexico that cause delays in or deter new drilling could adversely affect our business.

In response to the recent oil spill in the Gulf of Mexico, the Bureau of Ocean Energy Management, Regulation and Enforcement has issued and is expected to issue additional, new safety and environmental guidelines and/or regulations for drilling in the U.S. Gulf of Mexico, and potentially in other geographic regions, and may take other steps that could increase the costs of exploration and production, reduce the area of operations and result in permitting delays. These actions could cause delays or deter new drilling in the U.S. Gulf of Mexico or other areas that supply hydrocarbon volumes to our pipelines and facilities. As a result, future natural gas and crude oil volumes to our pipelines and facilities may decline or be lower than previously anticipated, which may adversely affect our financial position, results of operations and cash flows.

The recent adoption of derivatives legislation by the U.S. Congress could have an adverse effect on our ability to hedge risks associated with our business.

The U.S. Congress recently adopted comprehensive financial reform legislation, known as the Dodd-Frank Act, that establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The Dodd-Frank Act was signed into law by the President on July 21, 2010, and requires the Commodities Futures Trading Commission, or CFTC, and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. The act also requires the CFTC to institute broad new position limits for futures and options traded on regulated exchanges. As the law favors exchange trading and clearing, the Dodd-Frank Act also may require us to move certain derivatives transactions to exchanges where no trade credit is provided and also comply with margin requirements in connection with our derivatives activities that are not exchange traded, although the application of those provisions to us is uncertain at this time. The Dodd-Frank Act also requires many counterparties to our derivatives instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty, or cause the entity to comply with certain capital requirements, which could result in increased costs to counterparties such as us. The Dodd-Frank Act and any new regulations could

- significantly increase the cost of derivative contracts (including requirements to post collateral which could adversely affect our available liquidity);
- reduce the availability of derivatives to protect against risks we encounter; and
- reduce the liquidity of energy related derivatives.

If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Increased volatility may make us less attractive to certain types of investors. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our financial condition and results of operations.

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

None.

Item 3. Defaults Upon Senior Securities.

None.

Item 4. (Removed and Reserved)

Item 5. Other Information.

None.

Item 6. Exhibits.

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.

11 — Statement re: computation of per share earnings.

12 — Statement re: computation of ratio of earnings to fixed charges.

31.1 — Certification by CEO pursuant to Rule 13a-14 or 15d-14 of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 — Certification by CFO pursuant to Rule 13a-14 or 15d-14 of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 — Certification by CEO pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2 — Certification by CFO pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

101 — Interactive data files pursuant to Rule 405 of Regulation S-T: (i) our Consolidated Statements of Income for the three and nine month periods ended September 30, 2010 and 2009; (ii) our Consolidated Balance Sheets as of September 30, 2010 and December 31, 2009; (iii) our Consolidated Statements of Cash Flows for the nine months ended September 30, 2010 and 2009; and (iv) the notes to our Consolidated Financial Statements.

SIGNATURE

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

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

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

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

Date: October 29, 2010

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