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, 2009**

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 200,001,205 common units outstanding as of October 30, 2009.

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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,	
	2009	2008	2009	2008
Revenues				
Natural gas sales	$ 686.2	$ 2,183.3	$ 2,291.8	$ 6,369.2
Services	690.2	700.2	2,003.7	2,053.7
Product sales and other	284.3	349.3	797.0	1,025.9
Total Revenues	1,660.7	3,232.8	5,092.5	9,448.8
Operating Costs, Expenses and Other				
Gas purchases and other costs of sales	665.2	2,179.4	2,240.5	6,405.7
Operations and maintenance	280.3	353.5	797.6	948.1
Depreciation, depletion and amortization	202.9	166.8	616.2	490.5
General and administrative	83.7	73.1	238.8	222.7
Taxes, other than income taxes	36.4	48.0	98.8	147.0
Other expense (income)	(14.5)	4.1	(18.1)	1.3
Total Operating Costs, Expenses and Other	1,254.0	2,824.9	3,973.8	8,215.3
Operating Income	406.7	407.9	1,118.7	1,233.5
Other Income (Expense)				
Earnings from equity investments	59.8	34.6	139.9	118.5
Amortization of excess cost of equity investments	(1.4)	(1.4)	(4.3)	(4.3)
Interest, net	(103.0)	(98.3)	(296.2)	(293.8)
Other, net	12.9	4.3	43.8	30.5
Total Other Income (Expense)	(31.7)	(60.8)	(116.8)	(149.1)
Income from Continuing Operations Before Income Taxes	375.0	347.1	1,001.9	1,084.4
Income Taxes	(11.3)	(14.2)	(42.8)	(35.8)
Income from Continuing Operations	363.7	332.9	959.1	1,048.6
Discontinued Operations (Note 8):				
Adjustment to gain on disposal of North System	-	-	-	1.3
Income from Discontinued Operations	-	-	-	1.3
Net Income	363.7	332.9	959.1	1,049.9
Net Income attributable to Noncontrolling Interests	(4.2)	(3.1)	(11.9)	(11.2)
Net Income attributable to Kinder Morgan Energy Partners, L.P.	$ 359.5	$ 329.8	$ 947.2	$ 1,038.7
Calculation of Limited Partners' interest in Net Income Attributable to Kinder Morgan Energy Partners, L.P.:				
Income from Continuing Operations	$ 359.5	$ 329.8	$ 947.2	$ 1,037.4
Less: General Partner's interest	(236.2)	(205.6)	(692.7)	(588.9)
Limited Partners' interest	123.3	124.2	254.5	448.5
Add: Limited Partners' interest in Discontinued Operations	-	-	-	1.3
Limited Partners' interest in Net Income	$ 123.3	$ 124.2	$ 254.5	$ 449.8
Limited Partners' Net Income per Unit:				
Income from Continuing Operations	$ 0.43	$ 0.48	$ 0.92	$ 1.76
Income from Discontinued Operations	-	-	-	-
Net Income	$ 0.43	$ 0.48	$ 0.92	$ 1.76
Weighted average number of units used in computation of Limited Partners' Net Income per unit	286.6	258.8	277.9	255.5
Per unit cash distribution declared	$ 1.05	$ 1.02	$ 3.15	$ 2.97

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)
(Unaudited)

	September 30, 2009	December 31, 2008
ASSETS		
Current Assets		
Cash and cash equivalents	$ 168.8	$ 62.5
Restricted deposits	10.1	-
Accounts, notes and interest receivable, net	683.2	987.9
Inventories	56.6	44.2
Gas imbalances	15.7	14.1
Gas in underground storage	51.9	-
Fair value of derivative contracts	24.4	115.3
Other current assets	20.8	20.4
Total Current Assets	1,031.5	1,244.4
Property, plant and equipment, net	13,873.2	13,241.4
Investments	2,555.7	954.3
Notes receivable	189.9	178.1
Goodwill	1,097.6	1,058.9
Other intangibles, net	199.3	205.8
Fair value of derivative contracts	411.9	796.0
Deferred charges and other assets	195.5	206.9
Total Assets	$ 19,554.6	$ 17,885.8
LIABILITIES AND PARTNERS' CAPITAL		
Current Liabilities		
Current portion of debt	$ 155.6	$ 288.7
Cash book overdrafts	33.2	42.8
Accounts payable	411.4	855.6
Accrued interest	91.0	172.3
Accrued taxes	87.2	51.9
Deferred revenues	64.9	41.1
Gas imbalances	8.2	12.4
Fair value of derivative contracts	198.3	129.5
Accrued other current liabilities	123.9	187.8
Total Current Liabilities	1,173.7	1,782.1
Long-Term Liabilities and Deferred Credits		
Long-term debt		
Outstanding	10,247.4	8,274.9
Value of interest rate swaps	574.6	951.3
Total Long-term debt	10,822.0	9,226.2
Deferred revenues	11.8	12.9
Deferred income taxes	200.3	178.0
Asset retirement obligations	84.1	74.0
Fair value of derivative contracts	292.9	92.2
Other long-term liabilities and deferred credits	367.0	404.1
Total Long-Term Liabilities and Deferred Credits	11,778.1	9,987.4
Total Liabilities	12,951.8	11,769.5
Commitments and Contingencies (Notes 4 and 10)		
Partners' Capital		
Common Units	3,874.1	3,458.9
Class B Units	82.7	94.0
i-Units	2,658.9	2,577.1
General Partner	215.9	203.3
Accumulated other comprehensive loss	(306.2)	(287.7)
Total Kinder Morgan Energy Partners, L.P. Partners' Capital	6,525.4	6,045.6
Noncontrolling interests	77.4	70.7
Total Partners' Capital	6,602.8	6,116.3
Total Liabilities and Partners' Capital	$ 19,554.6	$ 17,885.8

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, 2009	Nine Months Ended September 30, 2008
Cash Flows From Operating Activities		
Net Income	$ 959.1	$ 1,049.9
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	616.2	490.5
Amortization of excess cost of equity investments	4.3	4.3
Income from the allowance for equity funds used during construction	(22.6)	-
Income from the sale or casualty of property, plant and equipment and other net assets	(18.1)	(13.0)
Earnings from equity investments	(139.9)	(118.5)
Distributions from equity investments	153.1	115.3
Proceeds from termination of interest rate swap agreements	144.4	-
Changes in components of working capital:		
Accounts receivable	227.3	(13.6)
Other current assets	(52.7)	11.1
Inventories	(11.8)	(6.8)
Accounts payable	(346.2)	(90.6)
Accrued interest	(81.3)	(65.3)
Accrued liabilities	(59.0)	68.4
Accrued taxes	35.4	18.9
Rate reparations, refunds and other litigation reserve adjustments	(15.5)	(10.7)
Other, net	(15.7)	(6.8)
Net Cash Provided by Operating Activities	1,377.0	1,433.1
Cash Flows From Investing Activities		
Acquisitions of assets	(27.5)	(9.0)
Repayments for Trans Mountain Pipeline	-	23.4
Repayments from customers	109.6	-
Capital expenditures	(1,075.4)	(1,914.4)
Sale or casualty of property, plant and equipment, and other net assets net of removal costs	9.1	48.8
(Investments in) Net proceeds from margin deposits	(13.2)	40.3
Contributions to equity investments	(1,619.1)	(341.6)
Distributions from equity investments	-	89.1
Natural gas stored underground and natural gas liquids line-fill	-	(2.5)
Net Cash Used in Investing Activities	(2,616.5)	(2,065.9)
Cash Flows From Financing Activities		
Issuance of debt	5,871.9	6,575.7
Payment of debt	(4,025.4)	(5,293.8)
Repayments from related party	2.5	1.8
Debt issue costs	(12.3)	(11.2)
(Decrease) Increase in cash book overdrafts	(9.6)	51.7
Proceeds from issuance of common units	815.5	384.3
Contributions from noncontrolling interests	11.0	6.7
Distributions to partners and noncontrolling interests:		
Common units	(599.2)	(501.9)
Class B units	(16.7)	(15.2)
General Partner	(680.3)	(557.6)
Noncontrolling interests	(16.3)	(13.9)
Other, net	(0.3)	3.1
Net Cash Provided by Financing Activities	1,340.8	629.7
Effect of exchange rate changes on cash and cash equivalents	5.0	(3.0)
Increase (Decrease) in Cash and Cash Equivalents	106.3	(6.1)
Cash and Cash Equivalents, beginning of period	62.5	58.9
Cash and Cash Equivalents, end of period	$ 168.8	$ 52.8
Noncash Investing and Financing Activities		
Assets acquired by the assumption or incurrence of liabilities	$ 3.7	$ 3.4
Assets acquired by the issuance of units	$ 5.0	$ 116.0
Supplemental Disclosures of Cash Flow Information		
Cash paid during the period for interest (net of capitalized interest)	$ 387.8	$ 352.3
Cash paid during the period for income taxes	$ 2.3	$ 35.0

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 more than 28,000 miles of pipelines and 170 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., formerly Knight Inc., a private company 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 owned by investors led by Richard D. Kinder, Chairman and Chief Executive Officer of Kinder Morgan G.P., Inc. (our general partner), and Kinder Morgan Management, LLC (our general partner's delegate). For a period, KMI was known as Knight Inc., the surviving legal entity from its May 30, 2007 going-private transaction. On July 15, 2009, Knight Inc. changed its name back to Kinder Morgan, Inc. For additional information regarding KMI's going-private transaction, see Note 1 to our consolidated financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2008, referred to in this report as our 2008 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 2008 Form 10-K.

Basis of Presentation

We have prepared our accompanying unaudited consolidated financial statements under the rules and regulations of the Securities and Exchange Commission. Under such rules and regulations, we have condensed or omitted certain information and notes normally included in financial statements prepared in conformity with accounting principles generally accepted in the United States of America.

We believe, however, that our disclosures are adequate to make the information presented not misleading. 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 2008 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—KMI—Asset Contributions," 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.

The Financial Accounting Standards Board's Accounting Standards Codification

In this report, we refer to the Financial Accounting Standards Board as the FASB; the FASB's issued Statements of Financial Accounting Standards as SFAS; the U.S. Securities and Exchange Commission as the SEC; and authoritative nongovernmental U.S. generally accepted accounting principles as GAAP.

In June 2009, the FASB voted to approve its Accounting Standards Codification as the single source of GAAP recognized by the FASB to be applied by nongovernmental entities. All other accounting literature not included in the Codification is considered nonauthoritative. In this report, we refer to the FASB Accounting Standards Codification as the Codification. It became effective for us on September 30, 2009, and although the adoption of the Codification did not have any direct effect on our consolidated financial statements, it does affect the way we reference GAAP in our financial statements and in our accounting policies.

The FASB now communicates new accounting standards via a new document called an Accounting Standards Update, referred to in this report as an ASU. Each ASU is a transient document—not considered authoritative in its own right—and serves only to update the Codification by detailing the specific amendments to the Codification and explaining the historical basis for conclusions of a new standard. The FASB will organize the content of each ASU using the same topics and section headings as those used in the Codification. For more information on Codification updates and other recent accounting pronouncements, see Note 12.

Noncontrolling Interests

On January 1, 2009, we adopted certain provisions concerning the accounting and reporting for noncontrolling interests included within the "Consolidation" Topic of the Codification. A noncontrolling interest, sometimes referred to as a minority interest, is the portion of equity in a subsidiary not attributable, directly or indirectly, to a parent.

Specifically, these provisions establish accounting and reporting standards that require (i) the ownership interests in subsidiaries held by parties other than the parent to be clearly identified, labeled, and presented in the consolidated balance sheet within equity, but separate from the parent's equity; and (ii) the equity amount of consolidated net income attributable to the parent and to the noncontrolling interest to be clearly identified and presented on the face of the consolidated income statement. Accordingly, our consolidated net income and comprehensive income are now determined without deducting amounts attributable to our noncontrolling interests, but our earnings-per-unit information continues to be calculated on the basis of the net income attributable to our limited partners.

The adopted provisions apply prospectively, with the exception of the presentation and disclosure requirements, which must be applied retrospectively for all periods presented. In addition, on June 12, 2009, we filed a Current Report on Form 8-K to update certain sections of our 2008 Form 10-K solely to reflect the retrospective presentation and disclosure requirements for noncontrolling interests. The Form 8-K included Item 6 "Selected Financial Data," Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Item 8 "Financial Statements and Supplementary Data," and no other items from our 2008 Form 10-K were adjusted or otherwise revised. The Form 8-K did not reflect any subsequent information or events other than the adoption of presentation and disclosure requirements for noncontrolling interests. Accordingly, whenever we refer in this report to disclosure contained in our 2008 Form 10-K, such references also apply to the relevant Form 10-K items included in the Form 8-K.

Limited Partners' Net Income per Unit

We compute Limited Partners' Net Income per Unit by dividing our limited partners' interest in net income by the weighted average number of units outstanding during the period. The overall computation, presentation, and disclosure requirements for our Limited Partners' Net Income per Unit are made in accordance with the "Earnings per Share" Topic of the Codification.

Among other things, this Topic contains (i) master limited partnership subsections that provide guidance for how current period earnings should be allocated between limited partners and a general partner when the partnership agreement contains incentive distribution rights; and (ii) provisions which clarify that share-based payment awards that entitle their holders to receive nonforfeitable dividends before vesting should be considered participating securities. As participating securities, these instruments should be included in the calculation of basic earnings per share. We adopted the subsections and provisions described above on January 1, 2009; however, the adoption did not have any impact on our consolidated financial statements.

Pensions and Other Postretirement Benefits

The Codification's "Defined Benefit Plans—General" Subtopic provides the accounting and disclosure requirements for the pension and other postretirement benefit plans sponsored by our subsidiaries. Effective December 31, 2009, certain provisions of this Subtopic will require additional disclosure of pension and postretirement benefit plan assets regarding (i) investment asset classes; (ii) fair value measurement of assets; (iii) investment strategies; (iv) asset risk; and (v) rate-of-return assumptions. Currently, we do not expect these provisions to have a material impact on our consolidated financial statements.

Subsequent Events

Effective June 30, 2009, the Codification's "Subsequent Events" Topic requires us to disclose the date through which we evaluate subsequent events and the basis for that date. For this report, we evaluated subsequent events—events or transactions that occurred after September 30, 2009 but before our accompanying consolidated financial statements were issued—through October 30, 2009, the date our management reviewed our accompanying consolidated financial statements. We issued the financial statements on the same day.

2. Acquisitions, Joint Ventures and Divestitures

Acquisitions

General

The provisions of the Codification's Topic 805, "Business Combinations," are to be effective prospectively for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. Accordingly, we adopted the provisions of Topic 805 on January 1, 2009. Topic 805 requires that (i) the acquisition method of accounting be used for all business combinations; and (ii) an acquirer be identified for each business combination. It applies to all transactions or other events in which an entity (the acquirer) obtains control of one or more businesses (the acquiree), including combinations achieved without the transfer of consideration. The adoption of Topic 805 did not have a material impact on our consolidated financial statements.

Significant provisions of Topic 805 concern principles and requirements for how an acquirer (i) recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree; (ii) recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase; and (iii) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. This Topic also amends the provisions related to the initial recognition and measurement, subsequent measurement and disclosure of assets and liabilities arising from contingencies in a business combination. It requires that acquired contingencies in a business combination be recognized at fair value on the acquisition date if fair value can be reasonably estimated during the allocation period. Otherwise, companies would typically account for the acquired contingencies in accordance with the provisions of the “Contingencies” Topic of the Codification.

Megafleet Towing Co., Inc. Assets

Effective April 23, 2009, we acquired certain terminals assets from Megafleet Towing Co., Inc. for an aggregate consideration of approximately $21.7 million. Our consideration included $18.0 million in cash and an obligation to pay additional cash consideration on April 23, 2014 (five years from the acquisition date) contingent upon the purchased assets providing us an agreed-upon amount of earnings, as defined by the purchase and sale agreement, during the five year period. The contingent consideration had a fair value of $3.7 million as of the acquisition date, and there has been no change in the fair value during the post-acquisition period ended September 30, 2009.

The acquired assets primarily consist of nine marine vessels that provide towing and harbor boat services along the Gulf coast, the intracoastal waterway, and the Houston Ship Channel. The acquisition complements and expands our existing Gulf Coast and Texas petroleum coke terminal operations, and all of the acquired assets are included in our Terminals business segment. We allocated $7.1 million of our combined purchase price to “Property, Plant and Equipment, net,” $4.0 million to “Other Intangibles net,” and the remaining $10.6 million to “Goodwill.” We believe the primary item that generated the goodwill is the value of the synergies created between the acquired assets and our pre-existing terminal assets (resulting from the increase in services now offered by our Texas petroleum coke operations), and we expect that approximately $5.0 million of goodwill will be deductible for tax purposes.

Joint Ventures

Rockies Express Pipeline

Rockies Express Pipeline LLC is the sole owner of the Rockies Express natural gas pipeline system and is referred to in this report as Rockies Express. West2East Pipeline LLC owns all of the member interests in Rockies Express LLC and West2East is owned 51% by us, 25% by Sempra Pipelines & Storage, and 24% by ConocoPhillips. After Rockies Express goes into service to Clarington, Ohio, referred to as project completion, the member interests and voting rights in West2East will change: we will own 50%, ConocoPhillips will own 25%, and votes required by the Board of Directors will require 75% of the interests. Also after project completion, West2East will merge with Rockies Express Pipeline LLC. Rockies Express Pipeline LLC will be the surviving company that will be owned 50% by us, and 25% by both Sempra and ConocoPhillips.

During the three and nine months ended September 30, 2009, we made capital contributions of $642.1 million and $1,075.6 million, respectively, to West2East Pipeline LLC to partially fund construction costs for the Rockies Express pipeline system and to fund the repayment of senior notes by Rockies Express which matured in August 2009. For more information on this additional contribution, see Note 4 “Debt—Contingent Debt—Rockies Express Pipeline LLC Debt.”

Midcontinent Express Pipeline

We own a 50% equity interest in Midcontinent Express Pipeline LLC, the sole owner of the Midcontinent Express natural gas pipeline system and referred to in this report as Midcontinent Express. Energy Transfer Partners, L.P. owns the remaining 50% equity ownership interest. During the three and nine months ended September 30, 2009, we made capital contributions of $131.5 million and $464.5 million, respectively, to Midcontinent Express to partially fund construction costs for the Midcontinent Express pipeline system. Construction of the pipeline was completed and the pipeline was placed in service on August 1, 2009. In January 2008, in conjunction with the signing of additional binding transportation commitments, Midcontinent Express entered into an option agreement with a subsidiary of MarkWest Energy Partners, L.P. providing it a one-time right to purchase a 10% ownership interest in Midcontinent Express. In September 2009, MarkWest declined to exercise this option.

Fayetteville Express Pipeline

We own a 50% equity interest in Fayetteville Express Pipeline LLC, the sole owner of the Fayetteville Express natural gas pipeline system and referred to in this report as Fayetteville Express. During the three and nine months ended September 30, 2009, we made capital contributions of $39 million and $70.2 million, respectively, to Fayetteville Express to partially fund certain pre-construction pipeline costs for the Fayetteville Express pipeline system.

We included all of the cash contributions to the three joint ventures described above as increases to "Investments" in our accompanying consolidated balance sheet as of September 30, 2009, and as "Contributions to equity investments" in our accompanying consolidated statement of cash flows for the nine months ended September 30, 2009. We use the equity method of accounting for each of the three investments, and as of September 30, 2009, the book value of our investments in West2East Pipeline LLC, Midcontinent Express, and Fayetteville Express were $1,559.5 million, $468.4 million, and $80.2 million, respectively.

In addition, on January 1, 2009, we also adopted certain provisions included within the "Investments—Equity Method and Joint Ventures" Topic of the Codification. These provisions clarify certain accounting and impairment considerations involving equity method investments. The adoption of these provisions did not have any impact on our consolidated financial statements. For more information on our joint ventures, see Note 11.

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, 2008 as if they had occurred as of January 1, 2008 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, 2009

Crosstex Energy, L.P. Natural Gas Treating Business

On August 31, 2009, we announced that we had entered into a partnership interest purchase and sales agreement to acquire the natural gas treating business from Crosstex Energy, L.P. and Crosstex Energy, Inc. for an aggregate consideration of approximately $266 million, subject to certain working capital and other closing adjustment provisions. The acquired assets primarily consist of approximately 290 natural gas amine-treating and dew-point control plants and related equipment, and are used to remove impurities and liquids from natural gas in order to meet pipeline quality specifications. The assets are predominantly located in Texas and Louisiana, with additional facilities located in Mississippi, Oklahoma, Arkansas and Kansas.

The acquisition makes us the largest provider of contract-provided treating plants in the U.S. and complements and expands the existing natural gas treating operations currently being offered by our Texas intrastate natural gas pipeline group. All of the acquired assets will be included in our Natural Gas Pipelines business segment. On October 1, 2009, the transaction closed. The acquired entity is named Kinder Morgan Treating LP.

GMX Resources Inc. Natural Gas Gathering Business

On October 16, 2009, we announced that we had entered into a definitive purchase agreement to acquire a 40% ownership interest in the natural gas gathering and compression business of GMX Resources Inc., referred to in this report as GMXR, for an aggregate consideration of approximately $36 million. The transaction is subject to customary closing conditions, including the release of liens on the midstream assets by certain lien holders, and is expected to close in early November 2009.

The gas gathering and compression business provides gas gathering service to GMXR's exploration and production activities in its Cotton Valley Sands and Haynesville/Bossier Shale horizontal well developments located in East Texas. GMXR's wholly owned subsidiary, Endeavor Pipeline Inc., will continue to act as operator of the system. The acquisition will complement our existing natural gas transportation business located in the state of Texas and all of the acquired investment will be included in our Natural Gas Pipelines business segment.

Divestitures

Cypress Pipeline

On July 14, 2009 we received notice from Westlake Petrochemicals LLC that it was exercising an option it held to purchase 50% of our Cypress Pipeline. We expect the transaction to close in the fourth quarter of 2009. As of September 30, 2009, the net assets of our Cypress Pipeline totaled approximately $21.2 million. The sale of 50% of our Cypress Pipeline will not have a material impact on our results of operations or our cash flows.

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, 2009 impairment testing, and no event indicating an impairment has occurred subsequent to that date. The fair value of each reporting unit was determined from the present value of the expected future cash flows from the applicable reporting unit (inclusive of a terminal value calculated using market multiples between six and ten times cash flows) discounted at a rate of 9.0%. The value of each reporting unit was determined on a stand-alone basis from the perspective of a market participant and represented the price that would be received to sell the unit as a whole in an orderly transaction between market participants at the measurement date.

Changes in the carrying amount of our goodwill for the nine months ended September 30, 2009 are summarized as follows (in millions):

	Products Pipelines	Natural Gas Pipelines	CO_2	Terminals	Kinder Morgan Canada	Total
Balance as of December 31, 2008	$ 263.2	$ 288.4	$ 46.1	$ 257.6	$ 203.6	$ 1,058.9
Acquisitions and purchase price adjustments	-	-	-	10.6	-	10.6
Currency translation adjustments	-	-	-	-	28.1	28.1
Balance as of September 30, 2009	$ 263.2	$ 288.4	$ 46.1	$ 268.2	$ 231.7	$ 1,097.6

In addition, we identify any premium or excess cost we pay over our proportionate share of the underlying fair value of net assets acquired and accounted for as investments under the equity method of accounting. This premium or excess cost is referred to as equity method goodwill and is also not subject to amortization but rather to impairment testing. No event or change in circumstances that may have a significant adverse effect on the fair value of our equity investments has occurred during the first nine months of 2009, and as of both September 30, 2009 and December 31, 2008, we reported $138.2 million in equity method goodwill within the caption “Investments” in our accompanying consolidated balance sheets.

Other Intangibles

Excluding goodwill, our other intangible assets include customer relationships, contracts and agreements, lease value, and technology-based assets. These intangible assets have definite lives, are being amortized on a straight-line basis over their estimated useful 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, 2009	December 31, 2008
Customer relationships, contracts and agreements		
Gross carrying amount	$ 247.6	$ 246.0
Accumulated amortization	(61.2)	(51.1)
Net carrying amount	186.4	194.9
Technology-based assets, lease value and other		
Gross carrying amount	15.7	13.3
Accumulated amortization	(2.8)	(2.4)
Net carrying amount	12.9	10.9
Total Other intangibles, net	$ 199.3	$ 205.8

For the three and nine months ended September 30, 2009, the amortization expense on our intangibles totaled $3.6 million and $10.5 million, respectively, and for the same prior year periods, the amortization expense on our intangibles totaled $3.8 million and $11.0 million, respectively. As of September 30, 2009, the weighted average amortization period for our intangible assets was approximately 16.6 years. Our estimated amortization expense for these assets for each of the next five fiscal years (2010 – 2014) is approximately $14.0 million, $13.8 million, $13.6 million, $13.5 million and $13.3 million, respectively.

In addition, on January 1, 2009, we adopted certain provisions included within the "General Intangibles Other than Goodwill" Subtopic of the Codification. These provisions introduce factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset. The adoption of these provisions did not have any impact on our consolidated financial statements.

4. Debt

We classify our debt based on the contractual maturity dates of the underlying debt instruments or as of the earliest put date available to the holders of the applicable debt. As of September 30, 2009, our outstanding short-term debt was $155.6 million, and our outstanding long-term debt (excluding the value of interest rate swap agreements) was $10,247.4 million. The weighted average interest rate on all of our borrowings (both short-term and long-term) was approximately 4.35% during the third quarter of 2009 and approximately 5.30% during the third quarter of 2008. For the first nine months of 2009 and 2008, the weighted average interest rate on all of our borrowings was approximately 4.66% and 5.46%, respectively.

As of September 30, 2009, our outstanding short-term debt balance consisted of (i) $110 million in outstanding borrowings under our bank credit facility (discussed below); (ii) $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); (iii) a $9.8 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); (iv) a $6.8 million portion of 5.23% senior notes (our subsidiary Kinder Morgan Texas Pipeline, L.P. is the obligor on the notes); and (v) $5.3 million in principal amount of adjustable rate industrial development revenue bonds that mature on January 1, 2010 (the bonds were issued by the Illinois Development Finance Authority and our subsidiary Arrow Terminals L.P. is the obligor on the bonds).

Credit Facility

Our $1.85 billion unsecured bank credit facility is with a syndicate of financial institutions, and Wachovia Bank, National Association is the administrative agent. The credit facility permits us to obtain bids for fixed rate loans from members of the lending syndicate, and the facility can be amended to allow for borrowings of up to $2.0 billion. Interest on our credit facility accrues at our option at a floating rate equal to either (i) the administrative agent's base rate (but not less than the Federal Funds Rate, plus 0.5%); or (ii) LIBOR, plus a margin, which varies depending upon the credit rating of our long-term senior unsecured debt.

The outstanding balance under our credit facility was $110 million as of September 30, 2009. As of December 31, 2008, there were no borrowings under the credit facility. The credit facility matures August 18, 2010 and currently, we plan to negotiate a renewal of the credit facility before its maturity date. Borrowings under our credit facility can be used for partnership purposes and as a backup for our commercial paper program.

During the first quarter of 2009, following Lehman Brothers Holdings Inc.'s filing for bankruptcy protection in September 2008, we amended the credit facility to remove Lehman Brothers Commercial Bank as a lender, thus reducing the borrowing capacity under the facility by $63.3 million. The commitments of the other banks remain unchanged, and the facility is not defaulted.

Additionally, as of September 30, 2009, the amount available for borrowing under our credit facility was reduced by an aggregate amount of $264.2 million, consisting of (i) a $100 million letter of credit that supports certain proceedings with the California Public Utilities Commission involving refined products tariff charges on the intrastate common carrier operations of our Pacific operations' pipelines in the state of California; (ii) a combined $90.8 million in three letters of credit that support tax-exempt bonds; (iii) a combined $35.0 million in two letters of credit that support our hedging of commodity price risks associated with the sale of natural gas, natural gas liquids and crude oil; (iv) a $21.4 million letter of credit that supports our indemnification obligations on the Series D note borrowings of Cortez Capital Corporation; and (v) a combined $17.0 million in other letters of credit supporting other obligations of us and our subsidiaries.

Commercial Paper Program

On October 13, 2008, Standard & Poor's Rating Services lowered our short-term credit rating to A-3 from A-2. Additionally, on May 6, 2009, Moody's Investor Services, 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 current commercial paper market conditions, we are currently unable to access commercial paper borrowings, and as of both September 30, 2009 and December 31, 2008, we had no commercial paper borrowings. However, we expect that our financing and liquidity needs will continue to be met through borrowings made under our bank credit facility described above.

Senior Notes

On February 1, 2009, we paid $250 million to retire the principal amount of our 6.30% senior notes that matured on that date. We borrowed the necessary funds under our bank credit facility.

On May 14, 2009, 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 $300 million of 5.625% notes due February 15, 2015, and $700 million of 6.85% notes due February 15, 2020. We received proceeds from the issuance of the notes, after underwriting discounts and commissions, of $993.3 million, and we used the proceeds to reduce the borrowings under our bank credit facility.

On September 16, 2009, we completed an additional public offering of senior notes. We issued a total of $1 billion in principal amount of senior notes in two separate series, consisting of $400 million of 5.80% notes due March 1, 2021, and $600 million of 6.50% notes due September 1, 2039. We received proceeds from the issuance of the notes, after underwriting discounts and commissions, of $987.4 million, and we used the proceeds to reduce the borrowings under our bank credit facility.

Kinder Morgan Operating L.P. "A" Debt

Effective January 1, 2007, we acquired the remaining approximately 50.2% interest in the Cochin pipeline system that we did not already own. As part of our purchase price consideration, two of our subsidiaries issued a long-term note payable to the seller having a fair value of $42.3 million. We valued the debt equal to the present value of amounts to be paid, determined using an annual interest rate of 5.40%. Our subsidiaries Kinder Morgan Operating L.P. "A" and Kinder Morgan Canada Company are the obligors on the note, and the principal amount of the note, along with interest, is due in five annual installments of $10.0 million beginning March 31, 2008. The final payment is due March 31, 2012. As of December 31, 2008, the net present value (representing the outstanding balance on our balance sheet) of the note was $36.6 million. We paid the second installment on March 31, 2009, and as of September 30, 2009, the net present value of the note was $27.8 million.

Interest Rate Swaps

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

Contingent Debt

Our contingent debt disclosures pertain to certain types of guarantees or indemnifications we have made and cover certain types of guarantees included within debt agreements, even if the likelihood of requiring our performance under such guarantee is remote. The following is a description of our contingent debt agreements as of September 30, 2009.

Cortez Pipeline Company Debt

Pursuant to a certain Throughput and Deficiency Agreement, the partners of Cortez Pipeline Company (Kinder Morgan CO_2 Company, L.P. – 50% partner; a subsidiary of Exxon Mobil Corporation – 37% partner; and Cortez Vickers Pipeline Company – 13% partner) are required, on a several, proportional percentage ownership basis, to contribute capital to Cortez Pipeline Company in the event of a cash deficiency. Furthermore, due to our indirect ownership of Cortez Pipeline Company through Kinder Morgan CO_2 Company, L.P., we severally guarantee 50% of the debt of Cortez Capital Corporation, a wholly-owned subsidiary of Cortez Pipeline Company.

As of September 30, 2009, the debt facilities of Cortez Capital Corporation consisted of (i) $42.9 million of Series D notes due May 15, 2013; (ii) a $125 million short-term commercial paper program; and (iii) a $125 million committed revolving credit facility due December 22, 2009 (to support the above-mentioned $125 million commercial paper program). Cortez is currently in the process of refinancing the $125 million credit facility and it expects to close on this refinancing in the fourth quarter of 2009. As of September 30, 2009, in addition to the $42.9 million of outstanding Series D notes, Cortez Capital Corporation had outstanding borrowings of $109.5 million under its credit facility. Accordingly, as of September 30, 2009, our contingent share of Cortez's debt was $76.2 million (50% of total guaranteed borrowings).

With respect to Cortez's Series D notes, the average interest rate on the notes is 7.14%, and the outstanding $42.9 million principal amount of the notes is due in four equal annual installments of approximately $10.7 million beginning May 2010. Shell Oil Company shares our several guaranty obligations jointly and severally; however, we are obligated to indemnify Shell for liabilities it incurs in connection with such guaranty. As of September 30, 2009, JP Morgan Chase has issued a letter of credit on our behalf in the amount of $21.4 million to secure our indemnification obligations to Shell for 50% of the $42.9 million in principal amount of Series D notes outstanding as of that date.

Nassau County, Florida Ocean Highway and Port Authority Debt

We have posted a letter of credit as security for borrowings under Adjustable Demand Revenue Bonds issued by the Nassau County, Florida Ocean Highway and Port Authority. The bonds were issued for the purpose of constructing certain port improvements located in Fernandino Beach, Nassau County, Florida. Our subsidiary, Nassau Terminals LLC is the operator of the marine port facilities. The bond indenture is for 30 years and allows the bonds to remain outstanding until December 1, 2020. Principal payments on the bonds are made on the first of December each year and corresponding reductions are made to the letter of credit. As of September 30, 2009, this letter of credit had a face amount of $21.2 million.

Rockies Express Pipeline LLC Debt

Pursuant to certain guaranty agreements, all three member owners of West2East Pipeline LLC (which owns all of the member interests in Rockies Express Pipeline LLC) have agreed to guarantee, severally in the same proportion as their percentage ownership of the member interests in West2East Pipeline LLC, borrowings under

Rockies Express' $2.0 billion five-year, unsecured revolving credit facility (due April 28, 2011) and Rockies Express' $2.0 billion commercial paper program. The three member owners and their respective ownership interests consist of the following: our subsidiary Kinder Morgan W2E Pipeline LLC – 51%, a subsidiary of Sempra Energy – 25%, and a subsidiary of ConocoPhillips – 24%.

Borrowings under the Rockies Express commercial paper program and/or its credit facility are primarily used to finance the construction of the Rockies Express interstate natural gas pipeline and to pay related expenses. The credit facility, which can be amended to allow for borrowings of up to $2.5 billion, supports borrowings under the commercial paper program, and borrowings under the commercial paper program reduce the borrowings allowed under the credit facility. Lehman Brothers Commercial Bank was a lending bank with a $41 million commitment under Rockies Express Pipeline LLC's $2.0 billion credit facility, and during the first quarter of 2009, Rockies Express amended its facility to remove Lehman Brothers Commercial Bank as a lender, thus reducing the borrowing capacity under the facility by $41.0 million. However, the commitments of the other banks remain unchanged, and the facility is not defaulted.

In October 2008, Standard & Poor's Rating Services lowered Rockies Express' short-term credit rating to A-3 from A-2. As a result of this revision and current commercial paper market conditions, Rockies Express is unable to access commercial paper borrowings; however, it expects that its financing and liquidity needs will continue to be met through both borrowings made under its long-term bank credit facility and contributions by its equity investors. As of September 30, 2009, Rockies Express had outstanding borrowings of $1,871.5 million under its credit facility. Accordingly, as of September 30, 2009, our contingent share of Rockies Express' debt was $954.5 million (51% of total guaranteed borrowings).

Additionally, on August 20, 2009, Rockies Express paid $600 million to retire the principal amount of its floating rate senior notes that matured on that date. It obtained the necessary funds to repay these senior notes from contributions received from its equity investors, including $306.0 million received from us (51% of total principal repayments).

Midcontinent Express Pipeline LLC Debt

Pursuant to certain guaranty agreements, each of the two member owners of Midcontinent Express Pipeline LLC have agreed to guarantee, severally in the same proportion as their percentage ownership of the member interests in Midcontinent Express, borrowings under its $1.4 billion three-year, unsecured revolving credit facility, entered into on February 29, 2008 and due February 28, 2011. The facility is with a syndicate of financial institutions with The Royal Bank of Scotland plc as the administrative agent. Borrowings under the credit facility are used to finance the construction of the Midcontinent Express pipeline system and to pay related expenses. Midcontinent Express is an equity method investee of ours, and the two member owners and their respective ownership interests consist of the following: our subsidiary Kinder Morgan Operating L.P. "A" – 50%, and Energy Transfer Partners, L.P. – 50%.

Lehman Brothers Commercial Bank was a lending bank with a $100 million commitment to the Midcontinent Express $1.4 billion credit facility, and following Lehman Brothers Holdings Inc.'s bankruptcy filing (discussed above), Lehman Brothers Commercial Bank has not met its obligations to lend under the credit facility, effectively reducing borrowing capacity under this facility by $100 million. The commitments of the other banks remain unchanged and the facility is not defaulted. As of September 30, 2009, Midcontinent Express had outstanding borrowings of $371.6 million under its three-year credit facility. Accordingly, as of September 30, 2009, our contingent share of Midcontinent Express' debt was $185.8 million (50% of total borrowings).

Furthermore, the credit facility can be used for the issuance of letters of credit to support the construction of the Midcontinent Express pipeline system, and as of September 30, 2009, a letter of credit having a face amount of $33.3 million was issued under the credit facility. Accordingly, as of September 30, 2009, our contingent responsibility with regard to this outstanding letter of credit was $16.7 million (50% of total face amount).

In October 2009, Midcontinent Express reduced the capacity on its credit facility from $1.4 billion to $275 million after completing the permanent long-term financing discussed below. On September 16, 2009, Midcontinent Express completed a private offering of senior notes. It issued an aggregate of $800 million in principal amount of fixed rate senior notes under an indenture between itself and U.S. Bank National Association, as trustee, in a private transaction that was not subject to the registration requirements of the Securities Act of 1933, but instead was subject to the requirements of Rule 144A under the Act. Midcontinent Express received net proceeds of $793.9 million from this offering, after deducting the initial purchasers' discount and estimated offering expenses, and the net proceeds from the sale of the notes were used to repay borrowings under its revolving credit facility.

The indenture provided for the issuance of two separate series of notes, as follows (i) $350 million in principal amount of 5.45% senior notes due September 15, 2014; and (ii) $450 million in principal amount of 6.70% senior notes due September 15, 2019. Interest on the notes will be paid semiannually on March 15 and September 15 of each year, commencing on March 15, 2010. All payments of principal and interest in respect of the notes are the sole obligation of Midcontinent Express. Noteholders will have no recourse against us, Energy Transfer Partners, or against any of our or their respective officers, directors, employees, members, managers, unitholders or affiliates for any failure by Midcontinent Express to perform or comply with its obligations pursuant to the notes or the indenture.

For additional information regarding our debt facilities and our contingent debt agreements, see Note 9 to our consolidated financial statements included in our 2008 Form 10-K.

5. Partners' Capital

Limited Partner Units

As of September 30, 2009 and December 31, 2008, our partners' capital included the following limited partner units:

	September 30, 2009	December 31, 2008
Common units	199,876,437	182,969,427
Class B units	5,313,400	5,313,400
i-units	83,754,953	77,997,906
Total limited partner units	288,944,790	266,280,733

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

As of September 30, 2009, our total common units consisted of 183,506,009 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, 2008, our common unit total consisted of 166,598,999 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, 2009 and December 31, 2008, 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. All of our Class B units were issued to a wholly-owned subsidiary of KMI in December 2000.

As of both September 30, 2009 and December 31, 2008, 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, 2009 and 2008, 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,					
	2009			2008		
	KMP	Noncontrolling interests	Total	KMP	Noncontrolling interests	Total
Beginning Balance	$ 6,267.7	$ 74.3	$ 6,342.0	$ 3,185.7	$ 42.5	$ 3,228.2
Units issued as consideration in the acquisition of assets	-	-	-	116.0	-	116.0
Units issued for cash	145.9	-	145.9	(0.2)	-	(0.2)
Distributions paid in cash	(448.1)	(5.5)	(453.6)	(377.2)	(5.0)	(382.2)
Express/Jet Fuel Pipelines acquisition	-	-	-	77.7	2.0	79.7
KMI going-private transaction expenses	1.5	-	1.5	7.2	-	7.2
Cash contributions	-	2.4	2.4	-	0.8	0.8
Comprehensive income (loss):						
Net Income	359.5	4.2	363.7	329.8	3.1	332.9
Other comprehensive loss:						
Change in fair value of derivatives utilized for hedging purposes	34.7	0.3	35.0	1,291.0	13.2	1,304.2
Reclassification of change in fair value of derivatives to net income	20.8	0.2	21.0	201.7	2.0	203.7
Foreign currency translation adjustments	143.0	1.5	144.5	(69.6)	(0.6)	(70.2)
Adjustments to pension and other postretirement benefit plan liabilities	0.4	-	0.4	0.7	(0.1)	0.6
Total other comprehensive	198.9	2.0	200.9	1,423.8	14.5	1,438.3
Comprehensive income	558.4	6.2	564.6	1,753.6	17.6	1,771.2
Ending Balance	$ 6,525.4	$ 77.4	$ 6,602.8	$ 4,762.8	$ 57.9	$ 4,820.7

	Nine Months Ended September 30,					
	2009			2008		
	KMP	Noncontrolling interests	Total	KMP	Noncontrolling interests	Total
Beginning Balance	$ 6,045.6	$ 70.7	$ 6,116.3	$ 4,435.7	$ 54.2	$ 4,489.9
Units issued as consideration pursuant to common unit compensation plan for non-employee directors	0.2	-	0.2	0.3	-	0.3
Units issued as consideration in the acquisition of assets	5.0	-	5.0	116.0	-	116.0
Units issued for cash	815.1	-	815.1	383.8	-	383.8
Distributions paid in cash	(1,296.2)	(16.3)	(1,312.5)	(1,074.7)	(13.9)	(1,088.6)
Trans Mountain Pipeline acquisition	25.7	0.3	26.0	23.2	0.2	23.4
Express/Jet Fuel Pipelines acquisition	(1.9)	-	(1.9)	77.7	2.0	79.7
Kinder Morgan North 40 terminal land acquisition	(0.9)	-	(0.9)	-	-	-
KMI going-private transaction expenses	4.3	-	4.3	7.2	-	7.2
Cash contributions	-	11.0	11.0	-	6.7	6.7
Other adjustments	(0.2)	-	(0.2)	-	-	-
Comprehensive income (loss):						
Net Income	947.2	11.9	959.1	1,038.7	11.2	1,049.9
Other comprehensive loss:						
Change in fair value of derivatives utilized for hedging purposes	(265.9)	(2.7)	(268.6)	(760.5)	(7.8)	(768.3)
Reclassification of change in fair value of derivatives to net income	34.0	0.3	34.3	624.3	6.4	630.7
Foreign currency translation adjustments	215.9	2.2	218.1	(113.0)	(1.1)	(114.1)
Adjustments to pension and other postretirement benefit plan liabilities	(2.5)	-	(2.5)	4.1	-	4.1
Total other comprehensive loss	(18.5)	(0.2)	(18.7)	(245.1)	(2.5)	(247.6)
Comprehensive income	928.7	11.7	940.4	793.6	8.7	802.3
Ending Balance	$ 6,525.4	$ 77.4	$ 6,602.8	$ 4,762.8	$ 57.9	$ 4,820.7

During the first nine months of both 2009 and 2008, there were no material changes in our ownership interests in subsidiaries in which we retained a controlling financial interest.

Equity Issuances

On January 16, 2009, we entered into an equity distribution agreement with UBS Securities LLC, referred to in this report as UBS. According to the provisions of this agreement, we may offer and sell from time to time common units having an aggregate offering value of up to $300 million through UBS, as sales agent. Sales of the units will be made by means of ordinary brokers' transactions on the New York Stock Exchange at market prices, in block transactions or as otherwise agreed between us and UBS. Under the terms of this agreement, we also may sell common units to UBS as principal for its own account at a price agreed upon at the time of the sale. Any sale of common units to UBS as principal would be pursuant to the terms of a separate agreement between us and UBS.

This equity distribution agreement provides us the right, but not the obligation, to sell common units in the future, at prices we deem appropriate. We retain at all times complete control over the amount and the timing of each sale, and we will designate the maximum number of common units to be sold through UBS, on a daily basis or otherwise as we and UBS agree. UBS will then use its reasonable efforts to sell, as our sales agent and on our behalf, all of the designated common units. We may instruct UBS not to sell common units if the sales cannot be effected at or above the price designated by us in any such instruction. Either we or UBS may suspend the offering of common units pursuant to the agreement by notifying the other party. During the three and nine months ended September 30, 2009, we issued 1,962,811 and 4,519,558, respectively, of our common units pursuant to this agreement. After commissions of $1.3 million and $3.6 million, respectively, for the three and nine month periods, we received net proceeds from the issuance of these common units of approximately $103.0 million and $227.6 million. We used the proceeds to reduce the borrowings under our bank credit facility. For more information concerning offerings subsequent to September 30, 2009, see "—Subsequent Event" below.

We also completed two separate underwritten public offerings of our common units in the first nine months of 2009, discussed following, and in April 2009, we issued 105,752 common units—valued at $5.0 million—as the purchase price for additional ownership interests in certain oil and gas properties.

In our first 2009 public offering, completed in March, we issued 5,666,000 of our common units at a price of $46.95 per unit, less underwriting commissions and expenses. We received net proceeds of $258.0 million for the issuance of these common units. In our second offering, completed in July, we issued 6,612,500 common units at a price of $51.50 per unit, less underwriting commissions and expenses, and we received net proceeds of $329.9 million for the issuance of these common units. We used the proceeds from each of these two public offerings to reduce the borrowings under 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 14, 2009, we paid a cash distribution of $1.05 per unit to our common unitholders and our Class B unitholders for the quarterly period ended June 30, 2009. KMR, our sole i-unitholder, received a distribution of 1,814,650 i-units from us on August 14, 2009, based on the preceding discussion of our i-units and the $1.05 per unit distributed to our common unitholders on that date. The distributions were declared on July 15, 2009, payable to unitholders of record as of July 31, 2009.

On October 21, 2009, we declared a cash distribution of $1.05 per unit for the quarterly period ended September 30, 2009. The distribution will be paid on November 13, 2009, to unitholders of record as of October 30, 2009. Our common unitholders and Class B unitholders will receive cash. KMR will receive a distribution of 1,783,310 additional i-units based on the $1.05 distribution per common unit. For each outstanding i-unit that KMR holds, a fraction of an i-unit (0.021292) will be issued. This fraction was determined by dividing:

▪ $1.05, the cash amount distributed per common unit

by

▪ $49.315, the average of KMR’s shares’ closing market prices from October 14-27, 2009, the ten consecutive trading days preceding the date on which the shares began to trade ex-dividend under the rules of the New York Stock Exchange.

Incentive distributions allocated to our general partner are determined by the amount quarterly distributions to unitholders exceed certain specified target levels. Our distribution of $1.05 per unit paid on August 14, 2009 for the second quarter of 2009 required an incentive distribution to our general partner of $231.8 million. Our distribution of $0.99 per unit paid on August 14, 2008 for the second quarter of 2008 resulted in an incentive distribution payment to our general partner in the amount of $194.2 million. The increased incentive distribution to our general partner paid for the second quarter of 2009 over the incentive distribution paid for the second quarter of 2008 reflects the increase in the amount distributed per unit as well as the issuance of additional units.

Our declared distribution for the third quarter of 2009 of $1.05 per unit will result in an incentive distribution to our general partner of $235.0 million. This compares to our distribution of $1.02 per unit and incentive distribution to our general partner of $204.3 million for the third quarter of 2008.

Subsequent Event

On October 1, 2009, we amended and restated our equity distribution agreement with UBS (discussed above in "—Equity Issuances") to allow for the offer and sale from time to time of common units having an aggregate offering value of up to $600 million through UBS, as sales agent. After September 30, 2009, and through October 30, 2009 (the date we evaluated subsequent events and issued our accompanying interim consolidated financial statements), we issued 124,768 of our common units pursuant to settlement of sales made before September 30, 2009 pursuant to our equity distribution agreement. After commissions of $0.1 million, we received net proceeds of $6.7 million for the issuance of these 124,768 common units, and we used the proceeds to reduce the borrowings under our bank credit facility.

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 associated with unfavorable price volatility related to (i) pre-existing or anticipated physical natural gas, natural gas liquids and crude oil sales; (ii) natural gas purchases; and (iii) natural gas system use and storage. The unfavorable price changes are often caused by shifts in the supply and demand for these commodities, as well as their locations.

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

For derivative contracts that are designated and qualify as cash flow hedges pursuant to generally accepted accounting principles, the portion of the gain or loss on the derivative contract that is effective in offsetting the variable cash flows associated with the hedged forecasted transaction is reported as a component of other comprehensive income and reclassified into earnings in the same line item associated with the forecasted transaction and in the same period or periods during which the hedged transaction affects earnings (e.g., in "revenues" when the hedged transactions are commodity sales). The remaining gain or loss on the derivative contract in excess of the cumulative change in the present value of future cash flows of the hedged item, if any (i.e., the ineffective portion), is recognized in earnings during the current period. The effectiveness of hedges using an option contract may be assessed based on changes in the option's intrinsic value with the change in the time value of the contract being excluded from the assessment of hedge effectiveness. Changes in the excluded component of the change in an option's time value are included currently in earnings. During the current period we recognized a net loss of $5.4 million related to crude oil hedges, which resulted from hedge ineffectiveness and amounts excluded from effectiveness testing.

During the three and nine months ended September 30, 2009, we reclassified losses of $21.0 million and $34.3 million, respectively, of "Accumulated other comprehensive loss" into earnings, and for the same comparable periods last year, we reclassified losses of $203.7 million and $630.7 million, respectively into earnings. All amounts reclassified into net income during the first nine months of both years resulted from the hedged forecasted transactions actually affecting earnings (i.e., when the forecasted sales and purchases actually occurred). No amounts were reclassified into earnings as a result of the discontinuance of cash flow hedges because it was probable that the original forecasted transactions would not occur by the end of the originally specified time period or within an additional two-month period of time thereafter. The proceeds or payments resulting from the settlement of 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 $306.2 million as of September 30, 2009, and $287.7 million as of December 31, 2008. These totals included “Accumulated other comprehensive loss” amounts associated with energy commodity price risk management activities of $295.9 million as of September 30, 2009 and $63.2 million as of December 31, 2008. Approximately $174.4 million of the total amount associated with energy commodity price risk management activities as of September 30, 2009 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, 2009, 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 2013.

As of September 30, 2009, we had entered into the following outstanding commodity forward contracts to hedge our forecasted energy commodity purchases and sales:

	Notional quantity
Derivatives designated as hedging contracts	
Crude oil	26.4 million barrels
Natural gas(a)	43.8 billion cubic feet
Derivatives not designated as hedging contracts	
Crude oil	0.1 million barrels
Natural gas(a)	1.5 billion cubic feet

(a) Notional quantities are shown net.

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

Effective at the beginning of the second quarter of 2008, we determined that the derivative contracts of our Casper and Douglas natural gas processing operations that previously had been designated as cash flow hedges for accounting purposes no longer met the hedge effectiveness assessment as required by accounting principles. Consequently, we discontinued hedge accounting treatment for these relationships (primarily crude oil hedges of heavy natural gas liquids sales) effective March 31, 2008. Since the forecasted sales of natural gas liquids volumes (the hedged item) were still expected to occur, all of the accumulated losses through March 31, 2008 on the related derivative contracts remained in accumulated other comprehensive income, and are not reclassified into earnings until the physical transactions occur. Any changes in the value of these derivative contracts subsequent to March 31, 2008 will no longer be deferred in other comprehensive income, but rather will impact current period income. The last of these derivative contracts will expire in December 2009.

Subsequent Event

In October 2009, we entered into forward contracts to hedge an additional 0.9 million barrels of crude oil.

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, 2008, we were a party to interest rate swap agreements with a total notional principal amount of $2.8 billion. During the first nine months of 2009, we both terminated an existing fixed-to-variable interest rate swap agreement having a notional principal amount of $300 million and a maturity date of March 15, 2031, and entered into sixteen separate fixed-to-variable swap agreements having a combined notional principal amount of $2.95 billion. We received proceeds of $144.4 million from the early termination of the $300 million swap agreement. In addition, an existing fixed-to-variable rate swap agreement having a notional principal amount of $250 million matured on February 1, 2009. This swap agreement corresponded with the maturity of our $250 million in principal amount of 6.30% senior notes that also matured on that date (discussed in Note 4).

Therefore, as of September 30, 2009, we had a combined notional principal amount of $5.2 billion of fixed-to-variable interest rate swap agreements effectively converting the interest expense associated with certain series of our senior notes from fixed rates to variable rates based on an interest rate of LIBOR plus a spread. All of our swap agreements have termination dates that correspond to the maturity dates of the related series of senior notes and, as of September 30, 2009, 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, 2009 and December 31, 2008 (in millions):

Fair Value of Derivative Contracts

	Asset derivatives				**Liability derivatives**			
	September 30, 2009		**December 31, 2008**		**September 30, 2009**		**December 31, 2008**	
	Balance sheet location	**Fair value**	**Balance sheet Location**	**Fair value**	**Balance Sheet location**	**Fair value**	**Balance sheet location**	**Fair value**
<u>Derivatives designated as hedging contracts</u>								
Energy commodity derivative contracts	Current	$ 21.8	Current	$ 113.5	Current	$ (196.8)	Current	$ (129.4)
	Non-current	67.1	Non-current	48.9	Non-current	(189.5)	Current	(92.2)
Subtotal		88.9		162.4		(386.3)		(221.6)
Interest rate swap agreements	Non-current	344.8	Non-current	747.1	Non-current	(103.4)		-
Total		433.7		909.5		(489.7)		(221.6)
<u>Derivatives not designated as hedging contracts</u>								
Energy commodity derivative contracts	Current	2.6	Current	1.8	Current	(1.5)	Current	(0.1)
Total derivatives		$ 436.3		$ 911.3		$ (491.2)		$ (221.7)

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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, 2009 and December 31, 2008, this unamortized premium totaled $333.2 million and $204.2 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 the three and nine months ended September 30, 2009 and 2008 (in millions):

Derivatives in fair value hedging relationships	Location of gain/(loss) recognized in income on derivative	Amount of gain/(loss) recognized in income on derivative(a)		Hedged items in fair value hedging relationships	Location of gain/(loss) recognized in income on related hedged item	Amount of gain/(loss) recognized in income on related hedged items(a)	
		Three Months				Three Months	
		2009	2008			2009	2008
Interest rate swap agreements	Interest, net – income/(expense)	$ 108.5	$ 70.3	Fixed rate debt	Interest, net – income/(expense)	$ (108.5)	$ (70.3)
Total		$ 108.5	$ 70.3	Total		$ (108.5)	$ (70.3)
		Nine Months				Nine Months	
		2009	2008			2009	2008
Interest rate swap agreements	Interest, net – income/(expense)	$ (361.3)	$ 61.2	Fixed rate debt	Interest, net – income/(expense)	$ 361.3	$ (61.2)
Total		$ (361.3)	$ 61.2	Total		$ 361.3	$ (61.2)

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

Derivatives in cash flow hedging relationships	Amount of gain/(loss) recognized in OCI on derivative (effective portion)		Location of gain/(loss) reclassified from Accumulated OCI into income (effective portion)	Amount of gain/(loss) reclassified from Accumulated OCI into income (effective portion)		Location of gain/(loss) recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)	Amount of gain/(loss) recognized in income on derivative (ineffective portion and amount excluded from effectiveness testing)	
	Three Months			Three Months			Three Months	
	2009	2008		2009	2008		2009	2008
Energy commodity derivative contracts	$ 35.0	$ 1,304.2	Revenues-natural gas sales	$ 4.8	$ (1.6)	Revenues	$ (5.4)	$ -
			Revenues-product sales and other	(53.5)	(215.4)			
			Gas purchases and other costs of sales	27.7	13.3	Gas purchases and other costs of sales	-	-
Total	$ 35.0	$ 1,304.2	Total	$ (21.0)	$ (203.7)	Total	$ (5.4)	$ -
	Nine Months			Nine Months			Nine Months	
	2009	2008		2009	2008		2009	2008
Energy commodity derivative contracts	$ (268.6)	$ (768.3)	Revenues-natural gas sales	$ 11.3	$ (4.9)	Revenues	$ (5.4)	$ -
			Revenues-product sales and other	(66.4)	(598.2)			
			Gas purchases and other costs of sales	20.8	(27.6)	Gas purchases and other costs of sales	-	(2.4)
Total	$ (268.6)	$ (768.3)	Total	$ (34.3)	$ (630.7)	Total	$ (5.4)	$ (2.4)

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,	
		2009	2008
Energy commodity derivative contracts	Gas purchases and other costs of sales	$ (0.8)	$ 12.2
Total		$ (0.8)	$ 12.2
		Nine Months Ended September 30,	
		2009	2008
Energy commodity derivative contracts	Gas purchases and other costs of sales	$ (3.1)	$ (0.9)
Total		$ (3.1)	$ (0.9)

The above disclosures regarding our derivative contracts and hedging activities are made pursuant to provisions included within the Codification's "Derivatives and Hedging" Topic. These provisions provide for enhanced disclosure requirements that include, among other things, (i) a tabular summary of the fair value of derivative contracts and their gains and losses; (ii) disclosure of derivative features that are credit-risk–related to provide more information regarding an entity's liquidity; and (iii) cross-referencing within footnotes to make it easier for financial statement users to locate important information about derivative contracts. We adopted these provisions on January 1, 2009, and the adoption of these disclosure provisions did not have a material impact on our consolidated financial statements.

Credit Risks

As discussed in Note 14 to our consolidated financial statements included in our 2008 Form 10-K, 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 a 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, 2009 was (in millions):

	Asset position
Interest rate swap agreements	$ 344.8
Energy commodity derivative contracts	91.5
Gross exposure	436.3
Netting agreement impact	(82.3)
Net exposure	$ 354.0

In conjunction with the purchase of exchange-traded derivative contracts or when the market value of our derivative contracts with specific counterparties exceeds established limits, we are required to provide collateral to our counterparties, which may include posting letters of credit or placing cash in margin accounts. As of September 30, 2009 and December 31, 2008, we had outstanding letters of credit totaling $35.0 million and $40.0 million, respectively, in support of our hedging of energy commodity price risks associated with the sale of natural gas, natural gas liquids and crude oil. Additionally, as of September 30, 2009, we had cash margin deposits associated with our energy commodity contract positions and over-the-counter swap partners totaling $10.1 million, and we reported this amount as "Restricted deposits" in our accompanying interim consolidated balance sheet. As of

December 31, 2008, our counterparties associated with our energy commodity contract positions and over-the-counter swap agreements had margin deposits with us totaling $3.1 million, and we reported this amount within "Accrued other liabilities" 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, 2009, 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	$ 71.8	$ 116.9
Two notches to below BBB-/Baa3 (below investment grade)	$ 63.9	$ 180.8

(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 one notch downgrade to BBB-/Baa3 by one agency would not trigger the entire $71.8 million incremental obligation.

(b) Includes current posting at current rating.

7. Fair Value

Our fair value measurements and disclosures are made in accordance with the "Fair Value Measurements and Disclosures" Topic of the Codification. This Topic establishes a single definition of fair value in generally accepted accounting principles and prescribes disclosures about fair value measurements.

We adopted the provisions of this Topic for our financial assets and financial liabilities effective January 1, 2008, and the adoption did not have a material impact on our balance sheet, statement of income, or statement of cash flows since we already applied its basic concepts in measuring fair values. With regard to our non-financial assets and non-financial liabilities, we adopted the provisions of this Topic effective January 1, 2009. This includes applying the provisions to (i) nonfinancial assets and liabilities initially measured at fair value in business combinations; (ii) reporting units or nonfinancial assets and liabilities measured at fair value in conjunction with goodwill impairment testing; (iii) other nonfinancial assets measured at fair value in conjunction with impairment assessments; and (iv) asset retirement obligations initially measured at fair value. The adoption for non-financial assets and liabilities did not have a material impact on our balance sheet, statement of income, or statement of cash flows since we already applied its basic concepts in measuring fair values.

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 both September 30, 2009 and December 31, 2008, based on the three levels established by the Codification and does not include cash margin deposits, which are reported as "Restricted deposits" in our accompanying consolidated balance sheets (in millions):

	Asset fair value measurements using			
	Total	**Quoted prices in active markets for identical assets (Level 1)**	**Significant other observable inputs (Level 2)**	**Significant unobservable inputs (Level 3)**
As of September 30, 2009				
Energy commodity derivative contracts(a)	$ 91.5	$ 0.1	$ 22.7	$ 68.7
Interest rate swap agreements	344.8	-	344.8	-
As of December 31, 2008				
Energy commodity derivative contracts(b)	$ 164.2	$ 0.1	$ 108.9	$ 55.2
Interest rate swap agreements	747.1	-	747.1	-

	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, 2009				
Energy commodity derivative contracts(c)	$ (387.8)	$ -	$ (349.0)	$ (38.8)
Interest rate swap agreements	(103.4)	-	(103.4)	-
As of December 31, 2008				
Energy commodity derivative contracts(d)	$ (221.7)	$ -	$ (210.6)	$ (11.1)
Interest rate swap agreements	-	-	-	-

(a) Level 1 consists primarily of NYMEX natural gas futures. 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 and West Texas Intermediate options.

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

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

(d) Level 2 consists primarily of OTC West Texas Intermediate hedges. Level 3 consists primarily of natural gas basis swaps, natural gas options and West Texas Intermediate options.

The table below provides a summary of changes in the fair value of our Level 3 energy commodity derivative contracts for the three and nine months ended September 30, 2009 and 2008 (in millions):

Significant unobservable inputs (Level 3)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	**2008**	**2009**	**2008**
Derivatives-net asset (liability)				
Beginning of Period	$ 24.0	$ (233.0)	$ 44.1	$ (100.3)
Realized and unrealized net losses	2.7	133.4	(19.1)	(52.9)
Purchases and settlements	3.2	19.0	4.9	72.6
Transfers in (out) of Level 3	-	-	-	-
End of Period	$ 29.9	$ (80.6)	$ 29.9	$ (80.6)
Change in unrealized net losses relating to contracts still held at end of period	$ (0.1)	$ 138.5	$ (29.5)	$ (22.3)

In addition, on both October 10, 2008 and June 30, 2009, we adopted separate provisions included within the "Fair Value Measurements and Disclosures" Topic of the Codification. The provisions adopted in October 2008 provide guidance clarifying how fair value measurements should be applied when valuing securities in markets that are not active, and reaffirm the notion of fair value as an exit price as of the measurement date. Among other things, the guidance also states that significant judgment is required in valuing financial assets. The adoption of these provisions was effective immediately; however, the adoption did not have any impact on our consolidated financial statements.

The provisions adopted on June 30, 2009 provide guidelines for making fair value measurements more consistent with the overall principles presented in the "Fair Value Measurements" Topic. They provide additional guidance to highlight and expand on the factors that should be considered in estimating fair value when there has been a significant decrease in market activity for a financial asset. The adoption of these provisions did not have a material impact on our consolidated financial statements.

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, 2009 and December 31, 2008 (both short-term and long-term, but excluding the value of interest rate swaps), is disclosed below (in millions):

	September 30, 2009		December 31, 2008	
	Carrying Value	**Estimated Fair Value**	**Carrying Value**	**Estimated Fair Value**
Total Debt	$ 10,403.0	$ 11,086.0	$ 8,563.6	$ 7,627.3

The above disclosure of the fair value of our financial instruments was made pursuant to certain provisions of the "Financial Instruments" Topic of the Codification and adopted by us on June 30, 2009. These provisions enhance consistency in financial reporting by increasing the frequency of fair value disclosures from annually to quarterly, in order to provide financial statement users with more timely information about the effects of current market conditions on financial instruments.

On that same day, we also adopted certain provisions included within the "Investments—Debt and Equity Securities" Topic of the Codification. These adopted provisions provide additional guidance designed to create greater clarity and consistency in accounting for and presenting impairment losses on securities. The provisions change (i) the method for determining whether an other-than-temporary impairment exists for debt securities; and (ii) the amount of an impairment charge to be recorded in earnings. The June 30, 2009 adoption of all of the provisions described above did not have a material impact on our consolidated financial statements.

For a more complete discussion of our fair value measurements, see Note 14 to our consolidated financial statements included in our 2008 Form 10-K.

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.

We evaluate performance principally based on each segments' earnings before depreciation, depletion and amortization, which excludes general and administrative expenses, third-party debt costs and interest expense, unallocable interest income and income tax expense, and net income attributable to noncontrolling interests. 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.

Selected financial information by segment follows (in millions):

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Revenues				
Products Pipelines				
Revenues from external customers	$ 216.7	$ 205.6	$ 611.6	$ 602.5
Natural Gas Pipelines				
Revenues from external customers	838.8	2,359.4	2,751.2	6,916.6
CO_2				
Revenues from external customers	262.3	305.2	749.4	900.2
Terminals				
Revenues from external customers	282.8	306.0	814.2	886.4
Intersegment revenues	0.2	0.2	0.7	0.7
Kinder Morgan Canada				
Revenues from external customers	60.1	56.6	166.1	143.1
Total segment revenues	1,660.9	3,233.0	5,093.2	9,449.5
Less: Total intersegment revenues	(0.2)	(0.2)	(0.7)	(0.7)
Total consolidated revenues	$ 1,660.7	$ 3,232.8	$ 5,092.5	$ 9,448.8

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Segment earnings before depreciation, depletion, amortization and amortization of excess cost of equity investments(a)				
Products Pipelines(b)	$ 167.9	$ 130.4	$ 468.3	$ 408.7
Natural Gas Pipelines	197.8	185.0	560.7	555.7
CO_2	193.2	203.3	563.3	619.7
Terminals	155.2	120.1	432.8	386.3
Kinder Morgan Canada	47.7	39.6	113.9	103.2
Total segment earnings before DD&A	761.8	678.4	2,139.0	2,073.6
Total segment depreciation, depletion and amortization	(202.9)	(166.8)	(616.2)	(490.5)
Total segment amortization of excess cost of investments	(1.4)	(1.4)	(4.3)	(4.3)
General and administrative expenses	(83.7)	(73.1)	(238.8)	(222.7)
Unallocable interest expense, net of interest income	(107.8)	(100.5)	(313.7)	(298.1)
Unallocable income tax expense	(2.3)	(3.7)	(6.9)	(8.1)
Total consolidated net income	$ 363.7	$ 332.9	$ 959.1	$ 1,049.9

	September 30, 2009	December 31, 2008
Assets		
Products Pipelines	$ 4,273.4	$ 4,183.0
Natural Gas Pipelines	7,043.1	5,535.9
CO_2	2,230.6	2,339.9
Terminals	3,540.9	3,347.6
Kinder Morgan Canada	1,755.9	1,583.9
Total segment assets	18,843.9	16,990.3
Corporate assets(c)	710.7	895.5
Total consolidated assets	$ 19,554.6	$ 17,885.8

(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 2008 amount includes a gain of $1.3 million from the October 2007 sale of our North System natural gas liquids pipeline and our 50% ownership interest in the Heartland Pipeline Company (collectively referred to in this report as our North System). We accounted for the North System business as a discontinued operation; however, because the sale did not change the structure of our internal organization in a manner that caused a change to our reportable business segments, we included the 2008 gain adjustment within our Products Pipelines business segment disclosures. Except for this gain adjustment on disposal of the North System, we recorded no other financial results from the operations of the North System during the first nine months of 2008.

(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

Plantation Pipe Line Company Note Receivable

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 December 31 and June 30 each year, with a final principal payment due July 20, 2011. The outstanding note receivable balance was $86.1 million as of September 30, 2009, and $88.5 million as of December 31, 2008. Of these amounts, $2.6 million and $3.7 million were included within "Accounts, notes and interest receivable, net," on our accompanying consolidated balance sheets as of September 30, 2009 and December 31, 2008, respectively, and the remainder was included within "Notes receivable" at each reporting date.

Express US Holdings LP Note Receivable

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. As of our acquisition date, the value of this unsecured debenture was equal to KMI's carrying value of $107.0 million. 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, 2009 and December 31, 2008, the outstanding note receivable balance, representing the translated amount included in our consolidated financial statements in U.S. dollars, was $106.1 million and $93.3 million, respectively, and we included these amounts within "Notes receivable" on our accompanying consolidated balance sheets.

KMI

Asset Contributions

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 partnership interest in TransColorado Gas Transmission Company 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 are insufficient to satisfy our obligations.

Significant Investors' Fair Value of Energy Commodity Derivative Contracts

As a result of the May 2007 going-private transaction of KMI (formerly Knight Inc.), as discussed in our 2008 Form 10-K, a number of individuals and entities became significant investors in KMI. By virtue of the size of their ownership interest in KMI, two of those investors became "related parties" to us (as that term is defined in authoritative accounting literature): (i) American International Group, Inc., referred to in this report as AIG, and certain of its affiliates; and (ii) Goldman Sachs Capital Partners and certain of its affiliates.

We and/or our affiliates enter into transactions with certain AIG affiliates in the ordinary course of their conducting insurance and insurance-related activities, although no individual transaction is, and all such transactions collectively are not, material to our consolidated financial statements. We also conduct 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. 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 which 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 related parties; and (ii) included within "Fair value of derivative contracts" on our accompanying consolidated balance sheets as of September 30, 2009 and December 31, 2008 (in millions):

	September 30, 2009	December 31, 2008
Derivatives – asset/(liability)		
Current assets	$ 1.6	$ 60.4
Noncurrent assets	$ 15.6	$ 20.1
Current liabilities	$ (43.3)	$ (13.2)
Noncurrent liabilities	$ (119.9)	$ (24.1)

Other

Generally, KMR makes all decisions relating to the management and control of our business. Our general partner owns all of KMR's voting securities. KMI, through its wholly owned and controlled subsidiary Kinder Morgan (Delaware), Inc., owns all the common stock of our general partner. Certain conflicts of interest could arise as a result of the relationships among KMR, our general partner, KMI and us; however, 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, see Note 12 to our consolidated financial statements included in our 2008 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, 2009. Additional information with respect to these proceedings can be found in Note 16 to our consolidated financial statements that were filed with our 2008 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, 2009.

In this note, we refer to SFPP, L.P. as SFPP; Calnev Pipe Line LLC as Calnev; Chevron Products Company as Chevron; Navajo Refining Company, L.P. as Navajo; ARCO Products Company as ARCO; BP West Coast Products, LLC as BP WCP; Texaco Refining and Marketing Inc. as Texaco; Western Refining Company, L.P. as Western Refining; ExxonMobil Oil Corporation as ExxonMobil; Tosco Corporation as Tosco; Ultramar Diamond Shamrock Corporation/Ultramar Inc. as Ultramar; Valero Energy Corporation as Valero; Valero Marketing and Supply Company as Valero Marketing; America West Airlines, Inc., Continental Airlines, Inc., Northwest Airlines, Inc., Southwest Airlines Co. and US Airways, Inc., collectively, as the Airlines; the United States Court of Appeals for the District of Columbia Circuit as the D.C. Circuit; and the Federal Energy Regulatory Commission, as the FERC.

Federal Energy Regulatory Commission Proceedings

- FERC Docket Nos. OR92-8, *et al.*—Complainants/Protestants: Chevron, Navajo, ARCO, BP WCP, Western Refining, ExxonMobil, Tosco, and Texaco (Ultramar is an intervenor)—Defendant: SFPP—Subject: Complaints against East Line and West Line rates; appeals pending at the D.C. Circuit.

- FERC Docket No. OR92-8-025—Complainants/Protestants: BP WCP; ExxonMobil; Chevron; ConocoPhillips; and Ultramar—Defendant: SFPP—Subject: Complaints against East Line and West Line rates and Watson Station Drain-Dry Charge; appeal pending at the D.C. Circuit.

- FERC Docket Nos. OR96-2, *et al.*—Complainants/Protestants: All Shippers except Chevron (which is an intervenor)—Defendant: SFPP—Subject: Complaints against all SFPP rates;

- FERC Docket No. OR02-4—Complainant/Protestant: Chevron—Defendant: SFPP; Subject: Complaint against SFPP rates; dismissed and Chevron appeal pending at the D.C. Circuit;

- FERC Docket Nos. OR03-5, OR04-3, OR05-4 & OR05-5—Complainants/Protestants: BP WCP, ExxonMobil, ConocoPhillips, the Airlines (other shippers intervened)—Defendant: SFPP—Subject: Complaints against all SFPP rates;

- FERC Docket Nos. OR07-1 & OR07-2—Complainant/Protestant: Tesoro—Defendant: SFPP—Subject: Complaints against North Line and West Line rates; held in abeyance;

- FERC Docket Nos. OR07-3 & OR07-6—Complainants/Protestants: BP WCP, Chevron, ConocoPhillips, ExxonMobil, Tesoro, and Valero Marketing—Defendant: SFPP—Subject: Complaints against 2005 and 2006 indexed rate increases; dismissed by FERC; appeal pending at D.C. Circuit;

- FERC Docket No. OR07-4—Complainants/Protestants: BP WCP, Chevron, and ExxonMobil—Defendants: SFPP, Kinder Morgan G.P., Inc., and KMI—Subject: Complaints against all SFPP rates; held in abeyance; complaint withdrawn as to SFPP's affiliates;

- FERC Docket Nos. OR07-5 & OR07-7 (consolidated) and IS06-296—Complainants/Protestants: ExxonMobil and Tesoro—Defendants: Calnev, Kinder Morgan G.P., Inc., and KMI—Subject: Complaints and protest against Calnev rates; OR07-5 and IS06-296 were settled in 2008; OR07-7 complaint amendment pending before FERC;

- FERC Docket Nos. OR07-18, OR07-19 & OR07-22—Complainants/Protestants: Airlines, BP WCP, Chevron, ConocoPhillips and Valero Marketing—Defendant: Calnev—Subject: Complaints against Calnev rates; complaint amendments pending before FERC;

- FERC Docket No. OR07-20—Complainant/Protestant: BP WCP—Defendant: SFPP—Subject: Complaint against 2007 indexed rate increases; dismissed by FERC; appeal pending at D.C. Circuit;

- FERC Docket Nos. OR08-13 & OR08-15—Complainants/Protestants: BP WCP and ExxonMobil—Defendant: SFPP—Subject: Complaints against all SFPP rates and 2008 indexed rate increases;

- FERC Docket No. IS05-230 (North Line rate case)—Complainants/Protestants: Shippers—Defendant: SFPP—Subject: SFPP filing to increase North Line rates to reflect expansion; initial decision issued; pending at FERC;

- FERC Docket No. IS07-137—Complainants/Protestants: Shippers—Defendant: SFPP—Subject: ULSD surcharge; settled;

- FERC Docket No. IS08-390—Complainants/Protestants: BP WCP, ExxonMobil, ConocoPhillips, Valero, Chevron, the Airlines—Defendant: SFPP—Subject: West Line rate increase; Initial Decision expected December 2009;

- FERC Docket No. IS09-375—Complainants/Protestants: BP, ExxonMobil, Chevron, Tesoro, ConocoPhillips, Western, Navajo, Valero, and Southwest (other shippers intervened)—Defendant: SFPP—Subject: Protests regarding 2009 indexed rate increases; protests dismissed by FERC;

- FERC Docket No. IS09-377—Complainants/Protestants: BP, Chevron, and Tesoro (other shippers intervened)—Defendant: Calnev—Subject: Protests regarding 2009 index-based rate increases; protests dismissed by FERC;

- FERC Docket No. IS09-437—Complainants/Protestants: BP WCP, ExxonMobil, ConocoPhillips, Valero, Chevron, Western Refining, and the Airlines—Defendant: SFPP—Subject: East Line rate increases;

- FERC Docket Nos. OR09-8/OR09-18/OR09-21 (not consolidated)—Complainants/Protestants: Chevron/Tesoro/BP WCP—Defendant: SFPP—Subject: Complaints against July 1, 2008 (Chevron/Tesoro) and July 1, 2009 (Tesoro/BP WCP) index-based rate increases;

- FERC Docket Nos. OR09-11/OR09-14 (not consolidated)—Complainants/Protestants: BP WCP/Tesoro—Defendant: Calnev—Subject: Complaints requesting audit of Page 700 of FERC Form No. 6 for 2007 and 2008;

- FERC Docket Nos. OR09-12/OR09-16 (not consolidated)—Complainants/Protestants: BP WCP/Tesoro—Defendant: SFPP—Subject: Complaints requesting audit of Page 700 of FERC Form No. 6 for 2007 and 2008;

- FERC Docket Nos. OR09-15/OR09-20 (not consolidated)—Complainants/Protestants: Tesoro/BP WCP—Defendant: Calnev—Subject: Complaints against all Calnev rates;

- FERC Docket Nos. OR09-17/OR09-22 (not consolidated)—Complainants/Protestants: Tesoro/BP WCP—Defendant: SFPP—Subject: Complaints against SFPP rates; and

- FERC Docket Nos. OR09-19/OR09-23 (not consolidated)—Complainants/Protestants: Tesoro/BP WCP—Defendant: Calnev—Subject: Complaints against July 1, 2009 index-based rate increases.

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

As to SFPP, the issues involved in these proceedings include, among others: (i) whether certain of our Pacific operations' rates are "grandfathered" under the Energy Policy Act of 1992, and therefore deemed to be just and reasonable; (ii) whether "substantially changed circumstances" have occurred with respect to any grandfathered rates such that those rates could be challenged; (iii) whether indexed rate increases are justified; and (iv) the appropriate level of return and income tax allowance we may include in our rates. The issues involving Calnev are similar.

During 2008, SFPP and Calnev made combined settlement payments to various shippers totaling approximately $30.2 million in connection with OR92-8-025, IS06-283 and OR07-5. In October 2008, SFPP entered into a settlement resolving disputes regarding its East Line rates filed in Docket No. IS08-28 and related dockets. In January 2009, the FERC approved the settlement. Reduced settlement rates became effective on May 1, 2009, and SFPP made refund and settlement payments totaling $15.5 million in May 2009.

Based on our review of these FERC proceedings, we estimate that as of September 30, 2009, shippers are seeking approximately $355 million in reparation and refund payments and approximately $30 to $35 million in additional annual rate reductions. We assume that, with respect to our SFPP litigation reserves, any reparations and accrued interest thereon will be paid no earlier than the end of 2009.

California Public Utilities Commission Proceedings

SFPP has previously reported ratemaking and complaint proceedings pending with the California Public Utilities Commission, referred to in this note as 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. As of the filing of this report, it is unknown when a decision from the CPUC regarding either of the two groups of consolidated matters will be issued. Based on our review of these CPUC proceedings, we estimate that shippers are seeking approximately $100 million in reparation and refund payments and approximately $35 million in annual rate reductions.

Carbon Dioxide Litigation

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

Kinder Morgan CO_2 Company, L.P., 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 and for violation of federal and Colorado antitrust laws. The plaintiffs seek actual damages, treble damages, punitive damages, a constructive trust and accounting, and declaratory relief. The defendants filed motions for summary judgment on all claims.

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

CO_2 Claims Arbitration

Cortez Pipeline Company and Kinder Morgan CO_2 Company L.P., successor to Shell CO_2 Company, Ltd. and referred to in this note as Kinder Morgan CO_2, 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 alleged that, in calculating royalty and other payments, defendants used a transportation expense in excess of what is allowed by the settlement agreement, thereby causing alleged underpayments of approximately $12 million. The plaintiffs also alleged that Cortez Pipeline Company should have used certain funds to further reduce its debt, which, in turn, would have allegedly increased the value of royalty and other payments by approximately $0.5 million. On August 7, 2006, the arbitration panel issued its opinion finding that defendants did not breach the settlement agreement. On June 21, 2007, the New Mexico federal district court entered final judgment confirming the August 7, 2006 arbitration decision.

On October 2, 2007, the plaintiffs initiated a second arbitration (*CO_2 Committee, Inc. v. Shell CO_2 Company, Ltd., aka Kinder Morgan CO_2 Company, L.P., et al.*) against Cortez Pipeline Company, Kinder Morgan CO_2 and an ExxonMobil entity. The second arbitration asserts claims similar to those asserted in the first arbitration. On June 3, 2008, the plaintiffs filed a request with the American Arbitration Association seeking administration of the arbitration. In October 2008, the New Mexico federal district court entered an order declaring that the panel in the first arbitration should decide whether the claims in the second arbitration are barred by res judicata. The plaintiffs filed a motion for reconsideration of that order, which was denied by the New Mexico federal district court in January 2009. Plaintiffs have appealed to the Tenth Circuit Court of Appeals and continue to seek administration of the second arbitration by the American Arbitration Association. The American Arbitration Association has indicated that it intends to stay any action pending the Tenth Circuit appeal.

MMS Matters

The U.S. Department of the Interior, Minerals Management Service, referred to in this note as the MMS, and Kinder Morgan CO_2 have reached a settlement of the previously reported Notice of Noncompliance and Civil Penalty from December 2006 and Orders to Report and Pay from March 2007 and August 2007. The settlement agreement is subject to final MMS approval and upon approval will be funded from existing reserves and indemnity payments by Shell CO_2 General LLC and Shell CO_2 LLC pursuant to a royalty claim indemnification agreement.

J. Casper Heimann, Pecos Slope Royalty Trust and Rio Petro LTD, individually and on behalf of all other private royalty and overriding royalty owners in the Bravo Dome Carbon Dioxide Unit, New Mexico similarly situated v. Kinder Morgan CO_2 Company, L.P., No. 04-26-CL (8th Judicial District Court, Union County New Mexico)

This case involves a purported class action against Kinder Morgan CO_2 alleging that it has failed to pay the full royalty and overriding royalty, collectively referred to as the royalty interests, on the true and proper settlement value of compressed carbon dioxide produced from the Bravo Dome Unit during the period beginning January 1, 2000. The complaint purports to assert claims for violation of the New Mexico Unfair Practices Act, constructive fraud, breach of contract and of the covenant of good faith and fair dealing, breach of the implied covenant to market, and claims for an accounting, unjust enrichment, and injunctive relief. The purported class is comprised of current and former owners, during the period January 2000 to the present, who have private property royalty interests burdening the oil and gas leases held by the defendant, excluding the Commissioner of Public Lands, the United States of America, and those private royalty interests that are not unitized as part of the Bravo Dome Unit.

The case was tried to a jury in the trial court in September 2008. The plaintiffs sought $6.8 million in actual damages as well as punitive damages. The jury returned a verdict finding that Kinder Morgan CO_2 did not breach the settlement agreement and did not breach the claimed duty to market carbon dioxide. The jury also found that Kinder Morgan CO_2 breached a duty of good faith and fair dealing and found compensatory damages of $0.3 million and punitive damages of $1.2 million. On October 16, 2008, the trial court entered judgment on the verdict.

On January 6, 2009, the district court entered orders vacating the judgment and scheduling a new trial beginning on October 19, 2009. On September 10, 2009, the parties signed a settlement agreement providing for a payment of $3.2 million to the class, a new royalty methodology pursuant to which future royalties will be based on a price formula that is tied in part to published crude oil prices, and a dismissal with prejudice of all claims. On October 22, 2009, the trial court entered final judgment approving the settlement.

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 response of the Colorado Department of Revenue to the Protest.

Montezuma County, Colorado Property Tax Assessment

On September 11, 2009, the County Assessor of Montezuma County, Colorado, issued Special Notices of Valuation to Kinder Morgan CO_2. The Special Notices of Valuation were revised on September 30, 2009. The revised Special Notices of Valuation were issued 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 filed a Protest of the revised Special Notices of Valuation and is now awaiting the County Assessor's response to that Protest. If tax bills are issued reflecting the Special Notices of Valuation, we expect that additional property taxes will be due from all interest owners at the McElmo Dome Unit in the amount of approximately $2.1 million, plus interest. Of this amount, 37.2% would be attributed to our interest. Upon payment of any additional taxes, we expect to file a petition for abatement or refund and 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 Union Pacific Railroad Company (the successor to Southern Pacific Transportation Company and referred to in this note as 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 2009.

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.

It is difficult to quantify the effects of the outcome of these cases on SFPP, because SFPP does not know UPRR's plans for projects or other activities that would cause pipeline relocations. 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.

United States of America, ex rel., Jack J. Grynberg v. K N Energy (Civil Action No. 97-D-1233, filed in the U.S. District Court, District of Colorado).

This multi-district litigation proceeding involves four lawsuits filed in 1997 against numerous Kinder Morgan companies. These suits were filed pursuant to the federal False Claims Act and allege underpayment of royalties due to mismeasurement of natural gas produced from federal and Indian lands. The complaints are part of a larger series of similar complaints filed by Mr. Grynberg against 77 natural gas pipelines (approximately 330 other defendants) in various courts throughout the country which were consolidated and transferred to the District of Wyoming.

In May 2005, a Special Master appointed in this litigation found that because there was a prior public disclosure of the allegations and that Grynberg was not an original source, the Court lacked subject matter jurisdiction. As a result, the Special Master recommended that the Court dismiss all the Kinder Morgan defendants. In October 2006, the United States District Court for the District of Wyoming upheld the dismissal of each case against the Kinder Morgan defendants on jurisdictional grounds. Grynberg appealed this Order to the Tenth Circuit Court of Appeals. Briefing was completed and oral argument was held on September 25, 2008. A decision by the Tenth Circuit Court of Appeals affirming the dismissal of the Kinder Morgan Defendants was issued on March 17, 2009.
Grynberg's petition for rehearing was denied on May 4, 2009 and the Tenth Circuit issued its Mandate on May 18,

2009. On October 5, 2009 the United States Supreme Court denied Grynberg's Petition for Writ of Certiorari, ending his appeal.

Prior to the dismissal order on jurisdictional grounds, the Kinder Morgan defendants filed Motions to Dismiss and for Sanctions alleging that Grynberg filed his Complaint without evidentiary support and for an improper purpose. On January 8, 2007, after the dismissal order, the Kinder Morgan defendants also filed a Motion for Attorney Fees under the False Claim Act. A decision is still pending on the Motions to Dismiss and for Sanctions and the Requests for Attorney Fees.

Severstal Sparrows Point Crane Collapse

On June 4, 2008, a bridge crane owned by Severstal Sparrows Point, LLC in Sparrows Point, Maryland collapsed while being operated by our subsidiary Kinder Morgan Bulk Terminals, Inc. According to our investigation, the collapse was caused by unexpected, sudden and extreme winds. On June 24, 2009, Severstal filed suit against Kinder Morgan Bulk Terminals in the United States District Court for the District of Maryland, cause no. WMN 09CV1668. Severstal alleges that we were contractually obligated to replace the collapsed crane and that our 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. Kinder Morgan Bulk Terminals denies each of Severstal's allegations.

Leukemia Cluster Litigation

Richard Jernee, et al v. Kinder Morgan Energy Partners, et al, No. CV03-03482 (Second Judicial District Court, State of Nevada, County of Washoe) ("Jernee").

Floyd Sands, et al v. Kinder Morgan Energy Partners, et al, No. CV03-05326 (Second Judicial District Court, State of Nevada, County of Washoe) ("Sands").

On May 30, 2003, plaintiffs, individually and on behalf of Adam Jernee, filed a civil action in the Nevada State trial court against us and several Kinder Morgan related entities and individuals and additional unrelated defendants. Plaintiffs in the Jernee matter claim that defendants negligently and intentionally failed to inspect, repair and replace unidentified segments of their pipeline and facilities, allowing "harmful substances and emissions and gases" to damage "the environment and health of human beings." Plaintiffs claim that "Adam Jernee's death was caused by leukemia that, in turn, is believed to be due to exposure to industrial chemicals and toxins." Plaintiffs purport to assert claims for wrongful death, premises liability, negligence, negligence per se, intentional infliction of emotional distress, negligent infliction of emotional distress, assault and battery, nuisance, fraud, strict liability (ultra hazardous acts), and aiding and abetting, and seek unspecified special, general and punitive damages.

On August 28, 2003, a separate group of plaintiffs, represented by the counsel for the plaintiffs in the Jernee matter, individually and on behalf of Stephanie Suzanne Sands, filed a civil action in the Nevada State trial court against the same defendants and alleging the same claims as in the Jernee case with respect to Stephanie Suzanne Sands. The Jernee case has been consolidated for pretrial purposes with the Sands case.

In July, 2009, plaintiffs in both the Sands and Jernee cases agreed to dismiss all claims against the Kinder Morgan related defendants with prejudice in exchange for the Kinder Morgan defendants' agreement that they would not seek to recover their defense costs against the plaintiffs. The Kinder Morgan defendants filed a Motion for Approval of Good Faith Settlement which was granted by the court on August 27, 2009, effectively concluding these cases with respect to all Kinder Morgan related entities and individuals.

Pipeline Integrity and Releases

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

Midcontinent Express Pipeline LLC Construction Incident

On July 15, 2009, a Midcontinent Express Pipeline LLC contractor and subcontractor were conducting a nitrogen pressure test on-facilities at a Midcontinent Express delivery meter station that was under construction-in Smith County, Mississippi. An unexpected release occurred during testing, resulting in one fatality and injuries to four other employees of the contractor or subcontractor. The United States Occupational Safety and Health Administration is investigating and has completed an on-site investigation into the cause of the incident with assistance from the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration, referred to in this note as the PHMSA. We are awaiting a report on the results of the investigation. All construction work at other Midcontinent Express meter sites was allowed to continue after safety and construction reviews confirmed that the work could resume safely.

Pasadena Terminal Fire

On September 23, 2008, a fire occurred in the pit 3 manifold area of our Pasadena, Texas terminal facility. One of our employees was injured and subsequently died. In addition, the pit 3 manifold was severely damaged.

On July 13, 2009, a civil lawsuit was filed by and on behalf of the family of the deceased employee entitled *Brandy Williams et. al. v. KMGP Services Company, Inc.* in the 133rd District Court of Harris County, Texas, case no. 2009-44321. The suit alleges one count of gross negligence against defendant and seeks unspecified compensatory and punitive damages. We have filed an Answer denying the allegations in the Complaint, and the parties are currently engaged in discovery.

Rockies Express Pipeline LLC Wyoming Construction Incident

On November 11, 2006, a bulldozer operated by an employee of Associated Pipeline Contractors, Inc., a third-party contractor to Rockies Express Pipeline LLC, struck an existing subsurface natural gas pipeline owned by Wyoming Interstate Company, a subsidiary of El Paso Pipeline Group. The pipeline was ruptured, resulting in an explosion and fire. The incident occurred in a rural area approximately nine miles southwest of Cheyenne, Wyoming. The incident resulted in one fatality (the operator of the bulldozer) and there were no other reported injuries. The cause of the incident was investigated by the PHMSA. In March 2008, the PHMSA issued a Notice of Probable Violation, Proposed Civil Penalty and Proposed Compliance Order, referred to in this note as a NOPV, to El Paso Corporation in which it concluded that El Paso failed to comply with federal law and its internal policies and procedures regarding protection of its pipeline, resulting in this incident.

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

In September 2007, the family of the deceased bulldozer operator filed a wrongful death action against us, Rockies Express and several other parties in the District Court of Harris County, Texas, 189th Judicial District, at case number 2007-57916. The plaintiffs seek unspecified compensatory and exemplary damages plus interest, attorney's fees and costs of suit. We have asserted contractual claims for complete indemnification for any and all costs arising from this incident, including any costs related to this lawsuit, against third parties and their insurers. On March 25, 2008, we entered into a settlement agreement with one of the plaintiffs, the decedent's daughter, resolving any and all of her claims against us, Rockies Express and its contractors. We were indemnified for the full amount of this settlement by one of Rockies Express' contractors. On October 17, 2008, the remaining plaintiffs filed a Notice of Nonsuit, which dismissed the remaining claims against all defendants without prejudice to the plaintiffs' ability to re-file their claims at a later date. The remaining plaintiffs re-filed their Complaint against Rockies Express, us and several other parties on November 7, 2008, Cause No. 2008-66788, currently pending in the District Court of Harris County, Texas, 189th Judicial District. The parties are currently engaged in discovery.

Charlotte, North Carolina

On November 27, 2006, the Plantation Pipeline experienced a release of approximately 95 barrels of gasoline from a Plantation Pipe Line Company block valve on a delivery line into a terminal owned by a third party company. The line was repaired and put back into service within a few days. Remediation efforts are continuing under the direction of the North Carolina Department of Environment and Natural Resources, referred to in this note as the NCDENR, which issued a Notice of Violation and Recommendation of Enforcement against Plantation on January 8, 2007. Plantation continues to cooperate fully with the NCDENR.

In April 2007, during pipeline maintenance activities near Charlotte, North Carolina, Plantation discovered the presence of historical soil contamination near the pipeline, and reported the presence of impacted soils to the NCDENR. Subsequently, Plantation contacted the owner of the property to request access to the property to investigate the potential contamination. The results of that investigation indicate that there is soil and groundwater contamination which appears to be from a historical turbine fuel release. The groundwater contamination is underneath at least two lots on which there is current construction of single family homes that are part of a new residential development. Further investigation and remediation are being conducted under the oversight of the NCDENR. Plantation reached a settlement with the builder of the two homes that were impacted. Plantation continues to negotiate with the owner of the property to address any potential claims that it may bring.

Barstow, California

The United States Department of Navy has alleged that historic releases of methyl tertiary-butyl ether, referred to in this report as 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 certain 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, plus potentially perform other work, if the parties determine it to be necessary, to ensure protection of the Navy's existing treatment system and water supply.

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, BC, 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, and the National Transportation Safety Board. Cleanup and environmental remediation is complete and we have applied to the British Columbia Ministry of Environment for a Certificate of Compliance confirming complete remediation. Certification is expected prior to year end.

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 Trans Mountain L.P. (the last two of which are subsidiaries of ours). The charges claim 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 Acts. We are of the view that the charges have been improperly laid against us, and we intend to vigorously defend against them.

General

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

Additionally, although it is not possible to predict the ultimate outcomes, we also believe, based on our experiences to date, that the ultimate resolution of these matters will not have a material adverse impact on our business, financial position, results of operations or cash flows. As of September 30, 2009 and December 31, 2008, we have recorded a total reserve for legal fees, transportation rate cases and other litigation liabilities in the amount of $207.7 million and $234.8 million, respectively. The reserve is primarily related to various claims from lawsuits arising from our West Coast products pipeline transportation rates, and the contingent amount is based on both the circumstances of probability and reasonability of dollar estimates. We regularly assess the likelihood of adverse outcomes resulting from these claims in order to determine the adequacy of our liability provision.

Environmental Matters

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.

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 for the first half of 2009 in order to allow the parties to work with the regulatory agency concerning the scope of the required cleanup. The regulatory agency has not yet made any final decisions concerning cleanup of the former terminal, although the agency is expected to issue final cleanup orders in 2009.

The lawsuit stay has now been lifted, and two new defendants have been added to the lawsuit by plaintiff in a Third Amended Complaint. Plaintiff's Third Amended Complaint alleges that future environmental cleanup costs at the former terminal will exceed $10 million, and that Plaintiff's past damages exceed $2 million. No trial date has yet been set.

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

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

The complaint seeks any and all damages related to remediating all environmental contamination at the terminal, and, according to the New Jersey Spill Compensation and Control Act, treble damages may be available for actual dollars incorrectly spent by the successful party in the lawsuit. The parties are currently involved in mandatory mediation and met in June and October 2008. No progress was made at any of the mediations. The mediation judge has referred the case back to the litigation court room.

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 Kinder Morgan Liquids Terminals LLC, f/k/a GATX Terminals Corporation. The complaint was filed in Gloucester County, New Jersey. Both ExxonMobil and KMLT filed third party complaints against Support Terminals seeking to bring Support Terminals into the case. Support Terminals filed motions to dismiss the third party complaints, which were denied. Support Terminals is now joined in the case and it filed an Answer denying all claims.

The plaintiffs seek the costs and damages that the plaintiffs allegedly have incurred or will incur as a result of the discharge of pollutants and hazardous substances at the Paulsboro, New Jersey facility. The costs and damages that the plaintiffs seek include cleanup costs and damages to natural resources. In addition, the plaintiffs seek an order compelling the defendants to perform or fund the assessment and restoration of those natural resource damages that are the result of the defendants' actions. As in the case brought by ExxonMobil against GATX Terminals, the issue is whether the plaintiffs' claims are within the scope of the indemnity obligations between GATX Terminals (and therefore, Kinder Morgan Liquids Terminals) and Support Terminals. The court has consolidated the two cases. All parties participated in mediation on October 26, 2009.

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. On October 3, 2007, we filed a Motion to Dismiss all counts of the Complaint. The court denied in part and granted in part the Motion to Dismiss and gave the City leave to amend their complaint. The City submitted its Amended Complaint and we filed an Answer. The parties have commenced with discovery. This site has been, and currently is, under the regulatory oversight and order of the California Regional Water Quality Control Board.

Kinder Morgan Port Manatee Terminal LLC, Palmetto, Florida

On June 18, 2009, our subsidiary Kinder Morgan Port Manatee Terminal LLC received a Revised Warning Letter from the Florida Department of Environmental Protection, referred to in this note as the Florida DEP, advising us of possible regulatory and air permit violations regarding operations at the Port Manatee, Florida terminal. We previously conducted a voluntary internal audit at this facility in March 2008 and identified various environmental compliance and permitting issues primarily related to air quality compliance. We reported our findings from this audit in a self-disclosure letter to the Florida DEP in March 2008. Following the submittal of our self-disclosure letter, the agency conducted numerous inspections of the air pollution control devices at the terminal and issued this Revised Warning Letter. We intend to schedule a meeting with the Florida DEP to attempt to resolve these issues.

In addition, we have received a subpoena from the U.S. Department of Justice for production of documents related to the service and operation of the Kinder Morgan Port Manatee terminal. We are fully cooperating with the investigation of this matter.

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 thereunder, 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 air, water and waste violations issued by various governmental authorities related to compliance with environmental 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 issued by various regulatory authorities related to compliance with environmental regulations associated with our assets. 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, 2009, we have accrued an environmental reserve of $74.9 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, 2009, we have recorded a receivable of $17.0 million for expected cost recoveries that have been deemed probable. As of December 31, 2008, our environmental reserve totaled $78.9 million and our estimated receivable for environmental cost recoveries totaled $20.7 million, respectively. Additionally, many factors may change in the future affecting our reserve estimates, such as (i) regulatory changes; (ii) groundwater and land use near our sites; and (iii) changes in cleanup technology.

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, 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

The following updates the disclosure in Note 17 to our audited financial statements that were filed with our 2008 Form 10-K, with respect to developments that occurred during the nine months ended September 30, 2009.

Order on Rehearing and Clarification - Standards of Conduct for Transmission Providers – Docket No. RM07-1-001

On October 15, 2009, the FERC issued Order No. 717-A, an order on rehearing and clarification regarding FERC's Affiliate Rule - Standards of Conduct. The FERC clarified a lengthy list of issues relating to: the applicability, the definition of transmission function and transmission function employees, the definition of marketing function and marketing function employees, the definition of transmission function information, independent functioning, transparency, training, and North American Energy Standards Board business practice standards. The FERC generally reaffirmed its determinations in Order No. 717, but granted rehearing on and clarified certain provisions. Order No. 717-A aims to make the Standards of Conduct clearer and to refocus the rules on the areas where there is the greatest potential for abuse. The Order addresses requests for rehearing and clarification of the following issues: (i) applicability of the Standards of Conduct to transmission owners with no marketing affiliate transactions; (ii) whether the Independent Functioning Rule applies to balancing authority employees; (iii) which activities of transmission function employees or marketing function employees are subject to the Independent Functioning Rule; (iv) whether local distribution companies making off-system sales on nonaffiliated pipelines are subject to the Standards of Conduct; (v) whether the Standards of Conduct apply to a pipeline's sale of its own production; (vi) applicability of the Standards of Conduct to asset management agreements; (vii) whether incidental purchases to remain in balance or sales of unneeded gas supply subject the company to the Standards of Conduct; (viii) applicability of the No Conduit Rule to certain situations; and (ix) applicability of the Transparency Rule to certain situations. The rehearing and clarification granted are not anticipated to have a material impact on the operation of our interstate pipelines.

Notice of Proposed Rulemaking – Natural Gas Price Transparency- Docket No. RM08-2-000

On November 20, 2008, the FERC issued Order 720 establishing new reporting requirements for interstate and major non-interstate natural gas pipelines. Interstate pipelines are required to post no-notice activity at each receipt and delivery point three days after the day of gas flow. Major non-interstate pipelines are required to daily post design capacity, scheduled volumes and available capacity at each receipt or delivery point with a design capacity of 15,000 MMBtus of natural gas per day or greater. The final rule became effective January 27, 2009 for interstate pipelines. On January 15, 2009, the FERC issued an order granting an extension of time for major non-interstate pipelines to comply until 150 days following the issuance of an order addressing the pending requests for rehearing. On January 16, 2009, the FERC granted rehearing of Order 720. On July 16, 2009, the FERC issued a request for supplemental comments on revisions to the posting requirements. Our intrastate pipeline group filed comments on August 31, 2009. We do not expect this Order to have a material impact on our consolidated financial statements.

Notice of Proposed Rulemaking - Contract Reporting Requirements of Intrastate Natural Gas Companies, Docket No. RM09-2-000.

On July 16, 2009, the FERC issued a Notice of Proposed Rulemaking proposing revisions to the existing transactional reporting requirements for intrastate and Hinshaw pipelines performing services in interstate commerce. The proposed revisions would require filings to be filed on a quarterly basis and to include more information than previously required. Comments are due on November 2, 2009.

Natural Gas Pipeline Expansion Filings

Rockies Express 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 Rockies Express Pipeline 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.

The expansion is fully contracted and is expected to be operational in the second quarter of 2010. The total FERC authorized cost for the proposed project is approximately $78 million; however, Rockies Express is currently projecting that the final actual cost will be less. By FERC order issued July 16, 2009, Rockies Express was granted authorization to construct and operate this project. Construction on this project commenced August 4, 2009.

Rockies Express Pipeline-East Project

Construction continued during the third quarter of 2009 on the previously announced Rockies Express Pipeline-East Pipeline project. The Rockies Express-East project includes the construction of an additional natural gas pipeline segment, comprising approximately 639 miles of 42-inch diameter pipeline commencing from the terminus of the Rockies Express-West pipeline to a terminus near the town of Clarington in Monroe County, Ohio. Current market conditions for consumables, labor and construction equipment along with certain provisions in the final regulatory orders have resulted in increased costs for the project and have impacted certain projected completion dates. Including expansions, our current estimate of total construction costs on the entire Rockies Express Pipeline is between $6.7 billion and $6.8 billion (consistent with our October 21, 2009 third quarter earnings press release).

On June 29, 2009, Rockies Express-East commenced service on the portion of the pipeline from Audrain County, Missouri to the Lebanon Hub in Warren County, Ohio. Currently, this section of the line provides capacity of approximately 1.8 billion cubic feet per day of natural gas, and includes interconnects to Natural Gas Pipeline Company of America LLC, Ameren, Trunkline, Midwestern Gas Transmission, Panhandle Eastern, Texas Eastern, Dominion Transmission and Columbia Gas, with future interconnects to Texas Gas Transmission, ANR, Citizens and Vectren. The remainder of Rockies Express-East, consisting of approximately 195 miles of 42-inch diameter pipe extending to Clarington, Ohio, is expected to be in service in November 2009 provided the horizontal directional drill across Deer Creek is successfully completed. When completed, the entire 1,679-mile Rockies Express Pipeline will have a capacity of approximately 1.8 billion cubic feet per day of natural gas, virtually all of which has been contracted under long-term firm commitments from creditworthy shippers.

Kinder Morgan Interstate Gas Transmission Pipeline - Huntsman 2009 Expansion Project

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

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

On April 16, 2009, KMLP received authorization from the FERC to begin service on Leg 2 of the approximately 133-mile, 42-inch diameter pipeline, and service on Leg 2 commenced April 18, 2009. On June 21, 2009, KMLP completed pipeline construction and placed the remaining portion of the pipeline system into service. The Kinder Morgan Louisiana Pipeline project cost approximately $1 billion to complete (consistent with our July 15, 2009 second quarter earnings press release).

The Kinder Morgan Louisiana Pipeline provides approximately 3.2 billion cubic feet per day of take-away natural gas capacity from the Cheniere Sabine Pass liquefied natural gas terminal, located in Cameron Parish, Louisiana, to various delivery points in Louisiana. The pipeline interconnects with multiple third-party pipelines and all of the capacity on the pipeline system has been fully subscribed by Chevron and Total under 20-year firm transportation contracts. Total’s contract became effective on June 21, 2009, and Chevron’s contract became effective on October 1, 2009.

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

On April 10, 2009, Midcontinent Express placed Zone 1 of the Midcontinent Express natural gas pipeline system into interim service. Zone 1 extends from Bennington, Oklahoma to the interconnect with Columbia Gulf Transmission Company in Madison Parish, Louisiana. It has a design capacity of approximately 1.5 billion cubic feet per day. On August 1, 2009, construction of the pipeline was completed, and Zone 2 was placed into service. Zone 2 extends from the Columbia Gulf interconnect to the terminus of the system in Choctaw County, Alabama. It has a design capacity of approximately 1.2 billion cubic feet per day. In an order issued September 17, 2009, the FERC approved Midcontinent Express’ (i) amendment to move one compressor station in Mississippi and modify the facilities at another station in Texas (both stations were among the facilities certificated in the July 2008 Order authorizing the system’s construction); and (ii) application to expand the capacity in Zone 1 by 0.3 billion cubic feet per day (this expansion is expected to be completed in December 2010).

The Midcontinent Express Pipeline is owned by Midcontinent Express Pipeline LLC, a 50/50 joint venture between us and Energy Transfer Partners, L.P. The pipeline originates near Bennington, Oklahoma and extends from southeast Oklahoma, across northeast Texas, northern Louisiana and central Mississippi, and terminates at an interconnection with the Transco Pipeline near Butler, Alabama. The approximate 500-mile natural gas pipeline system connects the Barnett Shale, Bossier Sands and other natural gas producing regions to markets in the eastern United States, and substantially all of the pipeline’s capacity is fully subscribed with long-term binding commitments from creditworthy shippers. The entire Midcontinent Express project cost approximately $2.3 billion to complete (consistent with our October 21, 2009 third quarter earnings press release).

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

Pipeline system development work continued during the third quarter of 2009 on the previously announced Fayetteville Express Pipeline project. The Fayetteville Express Pipeline is owned by Fayetteville Express Pipeline LLC, another 50/50 joint venture between us and Energy Transfer Partners, L.P. The Fayetteville Express Pipeline is a 187-mile, 42-inch diameter natural gas pipeline that will begin in Conway County, Arkansas, and end 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 June 15, 2009, Fayetteville Express filed its certificate application with the FERC. On October 15, 2009, the FERC issued its Environmental Assessment finding that, subject to compliance with certain conditions, the environmental impact of Fayetteville Express could be adequately mitigated. Pending regulatory approvals, the pipeline is expected to be in service by late 2010 or early 2011. Our estimate of the total costs of this pipeline project is approximately $1.2 billion (consistent with our October 21, 2009 third quarter earnings press release).

12. Recent Accounting Pronouncements

Securities and Exchange Commission's Final Rule on Oil and Gas Disclosure Requirements

On December 31, 2008, the Securities and Exchange Commission issued its final rule "Modernization of Oil and Gas Reporting," which revises the disclosures required by oil and gas companies. The SEC disclosure requirements for oil and gas companies have been updated to include expanded disclosure for oil and gas activities, and certain definitions have also been changed that will impact the determination of oil and gas reserve quantities. The provisions of this final rule are effective for registration statements filed on or after January 1, 2010, and for annual reports for fiscal years ending on or after December 31, 2009. We are currently reviewing the effects of this final rule.

SFAS Nos. 166 and 167

On June 12, 2009, the FASB published SFAS No. 166, "Accounting for Transfers of Financial Assets—an amendment of FASB Statement No. 140," and SFAS No. 167, "Amendments to FASB Interpretation No. 46(R)." These two Statements change the way entities account for securitizations and special-purpose entities, and both remain authoritative until such time that each is integrated into the Codification.

SFAS No. 166 will require more information about transfers of financial assets, including securitization transactions, and where companies have continuing exposure to the risks related to transferred financial assets. SFAS No. 167 changes how a company determines when an entity that is insufficiently capitalized or is not controlled through voting (or similar rights) should be consolidated. Both Statement Nos. 166 and 167 will be effective at the start of an entity's first fiscal year beginning after November 15, 2009 (January 1, 2010 for us). We do not expect the adoption of these Statements to have a material impact on our consolidated financial statements.

Accounting Standards Updates

In August 2009, the FASB issued ASU No. 2009-05, "Measuring Liabilities at Fair Value." This ASU amends the "Fair Value Measurements and Disclosures" Topic of the Codification to provide further guidance on how to measure the fair value of a liability. ASU No. 2009-05 is effective for the first reporting period beginning after issuance (September 30, 2009 for us), and the adoption of this ASU did not have a material impact on our consolidated financial statements.

In September 2009, the FASB issued five separate Accounting Standards Updates (ASU 2009 07-11) that make technical corrections to the Codification and codify certain SEC Observer comments made in conjunction with previous accounting issues. None of the five Accounting Standards Updates change existing accounting requirements.

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 2008 Form 10-K.

Critical Accounting Policies and Estimates

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

Further information about us and information regarding our accounting policies and estimates that we consider to be "critical" can be found in our 2008 Form 10-K. There have not been any significant changes in these policies and estimates during the nine months ended September 30, 2009.

Results of Operations

Consolidated

	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	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)	$ 167.9	$ 130.4	$ 37.5	29 %
Natural Gas Pipelines(c)	197.8	185.0	12.8	7 %
CO_2(d)	193.2	203.3	(10.1)	(5)%
Terminals(e)	155.2	120.1	35.1	29 %
Kinder Morgan Canada	47.7	39.6	8.1	20 %
Segment earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	761.8	678.4	83.4	12 %
Depreciation, depletion and amortization expense	(202.9)	(166.8)	(36.1)	(22)%
Amortization of excess cost of equity investments	(1.4)	(1.4)	-	-
General and administrative expense(f)	(83.7)	(73.1)	(10.6)	(15)%
Unallocable interest expense, net of interest income(g)	(107.8)	(100.5)	(7.3)	(7)%
Unallocable income tax expense	(2.3)	(3.7)	1.4	38 %
Net income	363.7	332.9	30.8	9 %
Net income attributable to noncontrolling interests(h)	(4.2)	(3.1)	(1.1)	(35)%
Net income attributable to Kinder Morgan Energy Partners, L.P.	$ 359.5	$ 329.8	$ 29.7	9 %

	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008	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)	$ 468.3	$ 408.7	$ 59.6	15%
Natural Gas Pipelines(j)	560.7	555.7	5.0	1%
CO_2(k)	563.3	619.7	(56.4)	(9)%
Terminals(l)	432.8	386.3	46.5	12%
Kinder Morgan Canada(m)	113.9	103.2	10.7	10%
Segment earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	2,139.0	2,073.6	65.4	3%
Depreciation, depletion and amortization expense	(616.2)	(490.5)	(125.7)	(26)%
Amortization of excess cost of equity investments	(4.3)	(4.3)	-	-
General and administrative expense(n)	(238.8)	(222.7)	(16.1)	(7)%
Unallocable interest expense, net of interest income(o)	(313.7)	(298.1)	(15.6)	(5)%
Unallocable income tax expense	(6.9)	(8.1)	1.2	15%
Net income	959.1	1,049.9	(90.8)	(9)%
Net income attributable to noncontrolling interests(p)	(11.9)	(11.2)	(0.7)	(6)%
Net income attributable to Kinder Morgan Energy Partners, L.P.	$ 947.2	$ 1,038.7	$ (91.5)	(9)%

(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) 2009 and 2008 amounts include a $1.1 million increase in income and a $0.7 million decrease in income, respectively, resulting from unrealized foreign currency gains and losses on long-term debt transactions. 2009 amount also includes a $0.1 million increase in income from hurricane casualty gains. 2008 amount also includes a $9.3 million decrease in income from the settlement of certain litigation matters related to our Pacific operations' East Line pipeline, and a $0.2 million decrease in income related to hurricane clean-up and repair activities.

(c) 2009 and 2008 amounts include a $0.7 million decrease in income and a $12.2 million increase in income, respectively, resulting from unrealized mark to market gains and losses due to the discontinuance of hedge accounting at Casper Douglas. 2009 amount also includes a $3.7 million increase in income from hurricane casualty gains. 2008 amount also includes a $4.4 million increase in expense related to hurricane clean-up and repair activities.

(d) 2009 amount includes a $5.4 million unrealized loss on derivative contracts used to hedge forecasted crude oil sales.

(e) 2009 amount includes an $11.2 million increase in income from hurricane and fire casualty gains. 2008 amount includes a $6.8 million decrease in income related to fire damage and repair activities, a $4.0 million decrease in income related to hurricane clean-up and repair activities, and a combined $1.5 million increase in expense associated with legal liability adjustments related to certain litigation matters involving our Elizabeth River bulk terminal and our Staten Island liquids terminal.

(f) Includes unallocated litigation and environmental expenses. 2009 and 2008 amounts include increases of $1.5 million and $1.4 million, respectively, in non-cash compensation expense allocated to us from KMI (we do not have any obligation, nor do we expect to pay any amounts related to these expenses). 2009 amount also includes a $0.5 million increase in expense for certain Natural Gas Pipeline asset acquisition costs, which under prior accounting standards would have been capitalized, and a $0.9 million decrease in expense related to capitalized overhead costs associated with the 2008 hurricane season. 2008 amount also includes a $0.1 million increase in expense related to hurricane clean-up and repair activities, and a $1.5 million decrease in expense due to the adjustment of certain insurance related liabilities.

(g) 2009 and 2008 amounts include increases in imputed interest expense of $0.4 million and $0.5 million, respectively, related to our January 1, 2007 Cochin Pipeline acquisition. 2008 amount also includes a $0.2 million increase in interest expense related to the settlement of certain litigation matters related to our Pacific operations' East Line pipeline.

(h) 2009 and 2008 amounts include an increase of $0.1 million and a decrease of $0.2 million, respectively, in net income attributable to our noncontrolling interests, related to all of the three month 2009 and 2008 items previously disclosed in these footnotes.

(i) 2009 and 2008 amounts include a $1.5 million increase in income and a $1.4 million decrease in income, respectively, resulting from unrealized foreign currency gains and losses on long-term debt transactions. 2009 amount also includes a $0.1 million increase in income from hurricane casualty gains, and a $3.8 million increase in expense associated with environmental liability adjustments. 2008 amount also includes a $9.3 million decrease in income from the settlement of certain litigation matters related to our Pacific operations' East Line pipeline, a $0.2 million decrease in income related to hurricane clean-up and repair activities, and a $1.3 million gain from the 2007 sale of our North System.

(j) 2009 and 2008 amounts include decreases in income of $4.5 million and $0.9 million, respectively, resulting from unrealized mark to market gains and losses due to the discontinuance of hedge accounting at Casper Douglas. 2009 amount also includes a $3.7 million increase in income from hurricane casualty gains. 2008 amount also includes a $4.4 million increase in expense related to hurricane clean-up and repair activities, and a $13.0 million gain from the sale of our 25% equity ownership interest in Thunder Creek Gas Services, LLC.

(k) 2009 amount includes a $5.4 million unrealized loss on derivative contracts used to hedge forecasted crude oil sales.

(l) 2009 amount includes an $11.2 million increase in income from hurricane and fire casualty gains, 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. 2008 amount includes a $6.8 million decrease in income related to fire damage and repair activities, a $4.0 million decrease in income related to hurricane clean-up and repair activities, and a combined $1.5 million increase in expense associated with legal liability adjustments related to certain litigation matters involving our Elizabeth River bulk terminal and our Staten Island liquids terminal.

(m) 2009 amount includes a $3.7 million decrease in expense due to a certain non-cash accounting change related to book tax accruals and foreign exchange fluctuations, and a $14.9 million increase in expense primarily due to certain non-cash regulatory accounting adjustments to the carrying amount of the previously established deferred tax liability.

(n) Includes unallocated litigation and environmental expenses. 2009 and 2008 amounts include increases of $4.3 million and $4.2 million, respectively, in non-cash compensation expense allocated to us from KMI (we do not have any obligation, nor do we expect to pay any amounts related to these expenses). 2009 amount also includes a $0.5 million increase in expense for certain Natural Gas Pipeline asset acquisition costs, which under prior accounting standards would have been capitalized, a $0.1 million increase in expense for certain Express pipeline system acquisition costs, which under prior accounting standards would have been capitalized, and a $2.4 million decrease in expense related to capitalized overhead costs associated with the 2008 hurricane season. 2008 amount also includes a $0.1 million increase in expense related to hurricane clean-up and repair activities, and a $1.5 million decrease in expense due to the adjustment of certain insurance related liabilities.

(o) 2009 and 2008 amounts include increases in imputed interest expense of $1.2 million and $1.5 million, respectively, related to our January 1, 2007 Cochin Pipeline acquisition. 2008 amount also includes a $0.2 million increase in interest expense related to the settlement of certain litigation matters related to our Pacific operations' East Line pipeline.

(p) 2009 and 2008 amounts include decreases of $0.1 million and $0.2 million, respectively, in net income attributable to our noncontrolling interests, related to all of the nine month 2009 and 2008 items previously disclosed in these footnotes.

For the quarterly period ended September 30, 2009, net income attributable to our partners, which includes all of our limited partner unitholders and our general partner, totaled $359.5 million. This compares to net income attributable to our partners of $329.8 million for the third quarter of 2008. Total revenues for the comparable third quarter periods were $1,660.7 million in 2009 and $3,232.8 million in 2008. For the nine months ended September 30, 2009 and 2008, net income attributable to our partners totaled $947.2 million and $1,038.7 million, respectively, on revenues of $5,092.5 million and $9,448.8 million, respectively.

Because our partnership agreement requires us to distribute 100% of our available cash to our partners on a quarterly basis (available cash as defined in our partnership agreement generally consists of all our cash receipts, less cash disbursements and changes in reserves), we consider each period's earnings before all non-cash depreciation, depletion and amortization expenses, including amortization of excess cost of equity investments, to be an important measure of our success in maximizing returns to our partners. We also use segment earnings before depreciation, depletion and amortization expenses (defined in the table above and sometimes referred to in this report as EBDA) internally as a measure of profit and loss used for evaluating segment performance and for deciding how to allocate resources to our five reportable business segments.

Total segment earnings before depreciation, depletion and amortization for the three months ended September 30, 2009 increased $83.4 million (12%) versus the same quarter last year. Combined, the certain items described in the footnotes to the tables accounted for $24.7 million of the increase in total segment EBDA (combining to increase total segment EBDA by $10.0 million in 2009 and to decrease total segment EBDA by $14.7 million in 2008). The remaining $58.7 million (8%) increase in total segment EBDA included higher earnings in 2009 from our Products Pipelines, Natural Gas Pipelines, Terminals and Kinder Morgan Canada business segments, slightly offset by lower earnings from our CO_2 business segment.

For the comparable nine month periods, the certain items described in the footnotes to the tables accounted for an increase in total segment EBDA of $6.2 million (combining to decrease total segment EBDA by $8.0 million in 2009 and to decrease total segment EBDA by $14.2 million in 2008). The remaining $59.2 million increase in total segment EBDA was driven by better performance from our Products Pipelines, Terminals, Kinder Morgan Canada and Natural Gas Pipelines business segments, offset by lower year-over-year earnings from our CO_2 business segment.

Products Pipelines

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(In millions, except operating statistics)			
Revenues(a)	$ 216.7	$ 205.6	$ 611.6	$ 602.5
Operating expenses(b)	(56.8)	(78.7)	(165.8)	(209.6)
Other income (expense)(c)	0.1	(0.1)	0.1	0.9
Earnings from equity investments(d)	6.5	5.0	19.9	21.2
Interest income and Other, net-income(e)	3.5	0.4	9.8	2.2
Income tax expense	(2.1)	(1.8)	(7.3)	(8.5)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 167.9	$ 130.4	$ 468.3	$ 408.7
Gasoline (MMBbl)(f)	101.3	101.1	301.2	299.5
Diesel fuel (MMBbl)	35.9	40.0	107.9	120.2
Jet fuel (MMBbl)	28.8	29.6	83.7	89.2
Total refined product volumes (MMBbl)	166.0	170.7	492.8	508.9
Natural gas liquids (MMBbl)	6.2	5.8	18.4	18.7
Total delivery volumes (MMBbl)(g)	172.2	176.5	511.2	527.6

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(a) 2008 amounts include a $5.1 million decrease in revenues from the settlement of certain litigation matters related to our Pacific operations' East Line pipeline.

(b) Nine month 2009 amount includes an increase in expense of $3.8 million associated with environmental liability adjustments. 2008 amounts include a $4.2 million increase in expense from the settlement of certain litigation matters related to our Pacific operations' East Line pipeline, and a $0.1 million increase in expense related to hurricane clean-up and repair activities. Nine month 2008 amount also includes a $3.0 million decrease in expense related to our Pacific operations and a $3.0 million increase in expense related to our Calnev Pipeline associated with legal liability adjustments.

(c) 2009 amounts include a gain of $0.1 million from hurricane casualty indemnifications. Nine month 2008 amount includes a gain of $1.3 million from the 2007 sale of our North System. We accounted for the North System business as a discontinued operation; however, because the sale does not change the structure of our internal organization in a manner that causes a change to our reportable business segments, we included this 2008 gain adjustment within our Products Pipelines business segment disclosures. Except for this gain adjustment on disposal of the North System, we recorded no other financial results from the operations of the North System during the first nine months of 2008.

(d) 2008 amounts include an expense of $0.1 million reflecting our portion of Plantation Pipe Line Company's expenses related to hurricane clean-up and repair activities.

(e) Three and nine month 2009 amounts include increases in income of $1.1 million and $1.5 million, respectively, resulting from unrealized foreign currency gains on long-term debt transactions. Three and nine month 2008 amounts include decreases in income of $0.7 million and $1.4 million, respectively, resulting from unrealized foreign currency losses on long-term debt transactions.

(f) Includes ethanol volumes.

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

The certain items related to our Products Pipelines business segment and described in the footnotes to the table above accounted for increases in earnings before depreciation, depletion and amortization expenses of $11.4 million and $7.4 million, respectively, when comparing to the same three and nine month periods a year ago. For each of the comparable three and nine month periods, the following is information related to the remaining increases and decreases in the segment's (i) earnings before depreciation, depletion and amortization expenses (EBDA); and (ii) operating revenues:

Three months ended September 30, 2009 versus Three months ended September 30, 2008

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Pacific operations	$ 10.2	17 %	$ 3.9	4 %
Transmix operations	8.8	128 %	8.0	78 %
West Coast Terminals	3.4	25 %	2.9	14 %
Central Florida Pipeline	2.8	26 %	2.7	20 %
Plantation Pipeline	1.3	15 %	(6.5)	(59)%
All others	(0.4)	(1)%	(5.0)	(9)%
Total Products Pipelines	$ 26.1	19 %	$ 6.0	3 %

Nine months ended September 30, 2009 versus Nine months ended September 30, 2008

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Pacific operations	$ 13.9	7 %	$ 0.4	-
Transmix operations	7.3	32 %	5.9	19 %
West Coast Terminals	12.6	34 %	11.5	20 %
Central Florida Pipeline	7.9	25 %	8.8	23 %
Plantation Pipeline	(0.8)	(3)%	(18.7)	(57)%
All others	11.3	(11)%	(3.9)	(2)%
Total Products Pipelines	$ 52.2	12 %	$ 4.0	1 %

Overall, our Products Pipelines business segment reported strong operating results in the third quarter of 2009 as earnings before depreciation, depletion and amortization expenses increased $26.1 million (19%), when compared to the third quarter of 2008. Although ongoing weak economic conditions continued to dampen demand for refined petroleum products at many of our assets in this segment, resulting in lower diesel and jet fuel volumes and flat gasoline volumes versus the third quarter of 2008, earnings were positively impacted by higher ethanol and terminal revenues from our Central Florida Pipeline and Pacific operations, improved warehousing margins at existing and expanded West Coast terminal facilities, and incremental product settlement gains from our transmix processing operations. In addition, the segment benefited from a $17.6 million (24%) reduction in combined operating expenses in the third quarter of 2009, primarily due to lower outside services and other discretionary operating expenses, lower fuel and power expenses, and to new service contracts and bidding work at lower prices compared to a year earlier.

The primary increases in segment earnings before depreciation, depletion and amortization expenses for both the three and nine months ended September 30, 2009, when compared to the same periods last year, were attributable to the third quarter 2009 earnings from our Pacific operations. For the comparable three month periods, the overall $10.2 million increase in our Pacific operations' earnings in 2009 consisted of a $3.9 million (4%) increase in revenues and a $6.3 million (18%) decrease in operating expenses, when compared to the third quarter a year ago. The overall increase in revenues was driven by both higher terminal revenues and higher year-over-year increases in tariff rates on refined products deliveries, which more than offset a 4% decline in delivery volumes. The quarterly decrease in expenses, relative to the third quarter 2008, was driven by a combination of aggressive cost management actions related to overall operating expenses (particularly outside services), lower legal expenses (due in part to incremental expenses associated with certain litigation settlements reached in the third quarter 2008), and higher product gains.

For the comparable nine month periods, the $13.9 million (7%) increase in our Pacific operations' earnings was driven by a $13.0 million decrease in combined operating expenses in the first nine months of 2009, when compared to the same prior year period. The decrease in expenses, relative to the first nine months of 2008, was primarily due to the following: (i) overall cost reductions and delays in certain non-critical spending; (ii) lower fuel and power and outside services expenses, due to lower mainline delivery volumes; (iii) higher product gains; (iv) lower right-of-way and environmental expenses; and (v) lower legal expenses (discussed above).

The higher period-to-period earnings before depreciation, depletion and amortization from our transmix processing operations in 2009 versus 2008 were mainly due to a combined $8.0 million increase to 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).

The period-to-period earnings increases from our West Coast terminal operations were largely revenue related, driven by increased warehouse charges and new customers at our combined Carson/Los Angeles Harbor terminal system and by incremental returns from the completion of a number of capital expansion projects that modified and upgraded terminal infrastructure since the end of the third quarter of 2008. Revenues from our remaining West Coast facilities increased in the third quarter and first nine months of 2009 due mostly to additional throughput and storage services associated with renewable fuels (both ethanol and biodiesel), and partly to incremental revenues from the terminals' Portland, Oregon Airport pipeline, which was acquired on July 31, 2009.

The increases in earnings before depreciation, depletion and amortization from our Central Florida Pipeline were also driven by higher period-to-period revenues in 2009, when compared to 2008. For the comparable three month periods, the increases in revenues and earnings were due to a 4% increase in throughput, a mid-year tariff increase, and higher product gains in 2009 versus 2008. For the comparable nine month periods, the increases in revenues and earnings were mainly due to incremental ethanol revenues created by the completion of expansion projects, mid-year tariff increases, and higher products transportation revenues.

The $1.3 million (15%) increase in earnings before depreciation, depletion and amortization from our approximate 51% equity ownership in the Plantation Pipe Line Company reflects higher net income earned by Plantation, primarily due to higher transportation revenues driven by a 1% increase in refined products delivery volumes (third quarter 2008 volumes were negatively affected by hurricane activity). The nine month decrease in earnings from our investment in Plantation was chiefly attributable to lower equity earnings as a result of lower pipeline oil loss allowance revenues earned by Plantation in 2009. The drop in oil loss allowance revenues in 2009 reflects the decline in refined product market prices since the end of the third quarter of 2008.

The overall decreases in revenues associated with our investment in Plantation in both the comparable three and nine month periods ($6.5 million (59%) for the comparable three months and $18.7 million (57%) for the comparable nine months) were mainly due to a restructuring of the Plantation operating agreement by ExxonMobil and us. On January 1, 2009, both parties agreed to reduce the fixed operating fees we earn from operating the pipeline and to charge pipeline operating expenses directly to Plantation, resulting in a minimal impact to our earnings. Accordingly, the reductions in our fee revenues were largely offset by corresponding decreases in our operating expenses of $7.0 million and $18.9 million, respectively.

Natural Gas Pipelines

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(In millions, except operating statistics)			
Revenues	$ 838.8	$ 2,359.4	$ 2,751.2	$ 6,916.6
Operating expenses(a)	(696.1)	(2,203.3)	(2,325.9)	(6,464.0)
Other income(b)	3.7	-	3.7	2.7
Earnings from equity investments	48.7	25.6	104.7	80.4
Interest income and Other, net-income(c)	3.8	3.9	31.1	21.8
Income tax expense	(1.1)	(0.6)	(4.1)	(1.8)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 197.8	$ 185.0	$ 560.7	$ 555.7
Natural gas transport volumes (Trillion Btus)(d)	633.3	512.5	1,683.6	1,495.7
Natural gas sales volumes (Trillion Btus)(e)	200.5	220.0	602.3	660.0

(a) Three and nine month 2009 amounts include decreases in income of $0.7 million and $4.5 million, respectively, due to unrealized mark to market losses due to the discontinuance of hedge accounting at Casper Douglas. Three and nine month 2008 amounts include an increase in income of $12.2 million and a decrease in income of $0.9 million, respectively, due to 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. 2008 amounts also include a $4.4 million increase in expense related to hurricane clean-up and repair activities.
(b) 2009 amounts represent gains from hurricane casualty indemnifications.
(c) Nine month 2008 amount includes a $13.0 million gain from the sale of our 25% equity ownership interest in Thunder Creek Gas Services, LLC.
(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.

The certain items related to our Natural Gas Pipelines business segment and described in the footnotes to the table above accounted for decreases in earnings before depreciation, depletion and amortization expenses of $4.8 million and $8.5 million, respectively, when comparing to the same three and nine month periods a year ago. For each of the comparable three and nine month periods, the following is information related to (i) the remaining changes in segment earnings before depreciation, depletion and amortization expenses (EBDA); and (ii) the changes in operating revenues:

Three months ended September 30, 2009 versus Three months ended September 30, 2008

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Rockies Express Pipeline	$ 15.9	84 %	$ -	-
Midcontinent Express Pipeline	7.0	n/a	-	-
Kinder Morgan Louisiana Pipeline	6.1	205 %	8.5	n/a
Texas Intrastate Natural Gas Pipeline Group	(6.5)	(7)%	(1,504.1)	(67)%
TransColorado Pipeline	(2.1)	(15)%	(0.9)	(6)%
Kinder Morgan Interstate Gas Transmission	(2.0)	(7)%	(8.8)	(17)%
All others	(0.8)	(4)%	(15.3)	(32)%
Intrasegment eliminations	-	-	-	-
Total Natural Gas Pipelines	$ 17.6	(10)%	$ (1,520.6)	(64)%

Nine months ended September 30, 2009 versus Nine months ended September 30, 2008

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Rockies Express Pipeline	$ 18.2	31 %	$ -	-
Midcontinent Express Pipeline	7.2	n/a	-	-
Kinder Morgan Louisiana Pipeline	22.0	365 %	8.5	n/a
Texas Intrastate Natural Gas Pipeline Group	(34.8)	(12)%	(4,096.6)	(62)%
TransColorado Pipeline	(2.6)	(6)%	(1.4)	(3)%
Kinder Morgan Interstate Gas Transmission	7.5	9 %	(13.3)	(9)%
All others	(4.0)	(6)%	(65.0)	(42)%
Intrasegment eliminations	-	-	2.4	73 %
Total Natural Gas Pipelines	$ 13.5	(10)%	$ (4,165.4)	(60)%

For the third quarter of 2009, the increase in earnings from our 51% equity investment in the Rockies Express joint venture pipeline was mainly attributable to the Rockies Express-East natural gas pipeline segment, which began initial pipeline service on June 29, 2009. The increase in our share of net income for the comparable nine month periods was attributable to incremental income from both the Rockies Express-East line and the Rockies Express-West natural gas pipeline segment, which began full operations in May 2008.

Similarly, the increases in earnings from our 50% equity investment in the Midcontinent Express joint venture pipeline relate to the start of natural gas transportation service on the Midcontinent Express system, which commenced interim service for Zone 1 of its pipeline system on April 10, 2009, with deliveries to Natural Gas Pipeline Company of America LLC. Natural gas service to all Zone 1 delivery points occurred by May 21, 2009, and on August 1, 2009, the system's remaining portion (Zone 2) was placed into service.

The $6.1 million increase in earnings before depreciation, depletion and amortization expenses from our Kinder Morgan Louisiana Pipeline in the third quarter of 2009 was primarily attributable to pipeline in-service, which commenced on a limited basis in April 2009, and in full on June 21, 2009. For the comparable nine month periods, the incremental earnings in 2009 were mainly attributable to $16.4 million in higher other non-operating income. Pursuant to FERC regulations governing allowances for capital funds that are used for pipeline construction costs (an equity cost of capital allowance), we are allowed a reasonable return on the construction costs that are funded by equity contributions, similar to the allowance for capital costs funded by borrowings.

Our Texas intrastate natural gas pipeline group accounted for 44% and 46%, respectively, of the segment's total earnings before depreciation, depletion and amortization expenses in the three and nine months ended September 30, 2009. The period-to-period decreases in earnings from our intrastate group were mainly attributable to (i) lower margins from natural gas sales—due primarily to lower average natural gas sales prices in 2009; (ii) lower natural gas processing margins—due to unfavorable gross processing spreads as a result of significantly lower average natural gas liquids prices in 2009; and (iii) higher system operational expenses—due primarily to higher pipeline integrity expenses. The overall decreases in earnings were partially offset by higher period-to-period natural gas storage margins which resulted from favorable proprietary and fee based storage activities.

The overall changes in both total segment revenues and total segment operating expenses primarily relate to the natural gas purchase and sale activities of our Texas intrastate natural gas pipeline group. Our intrastate group both purchases and sells significant volumes of natural gas, which is often stored and/or transported on its pipelines, and due to the fact that the group 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 gas purchase costs.

The decreases in quarterly and year-to-date earnings from our TransColorado Pipeline in 2009 versus 2008 were primarily due to decreases in natural gas transportation revenues and increases in both pipeline remediation expenses and property tax expenses in the third quarter and first nine months of 2009, relative to the same periods in 2008.

Earnings before depreciation, depletion and amortization from our Kinder Morgan Interstate Gas Transmission pipeline system decreased $2.0 million (7%) in the comparable three month periods, but increased $7.5 million (9%) in the comparable nine month periods. The quarter-to-quarter decrease in earnings was driven by a $1.8 million expense associated with an unfavorable net carrying value adjustment of gas in underground storage recognized in the third quarter of 2009. The increase in earnings in the comparable nine month periods was driven by an operating margin increase of $7.3 million (7%) in 2009, due mainly to higher firm transportation demand fees from system expansions and incremental ethanol customers, higher earnings from natural gas park and loan services, and higher pipeline fuel recoveries, relative to the same nine month period a year ago.

CO_2

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(In millions, except operating statistics)			
Revenues(a)	$ 262.3	$ 305.2	$ 749.4	$ 900.2
Operating expenses	(72.5)	(105.4)	(198.4)	(292.7)
Earnings from equity investments	5.5	4.2	16.4	15.3
Other, net-expense	(1.2)	-	(1.2)	(0.2)
Income tax benefit expense	(0.9)	(0.7)	(2.9)	(2.9)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 193.2	$ 203.3	$ 563.3	$ 619.7
Carbon dioxide delivery volumes (Bcf)(b)	178.3	171.3	579.7	530.1
SACROC oil production (gross)(MBbl/d)(c)	29.6	27.9	30.2	27.6
SACROC oil production (net)(MBbl/d)(d)	24.7	23.3	25.2	23.0
Yates oil production (gross)(MBbl/d)(c)	26.4	27.1	26.6	27.9
Yates oil production (net)(MBbl/d)(d)	11.7	12.0	11.8	12.4
Natural gas liquids sales volumes (net)(MBbl/d)(d)	9.5	7.6	9.3	8.7
Realized weighted average oil price per Bbl(e)(f)	$ 51.42	$ 51.45	$ 48.27	$ 51.50
Realized weighted average natural gas liquids price per Bbl(f)(g)	$ 40.28	$ 77.97	$ 34.31	$ 73.37

(a) 2009 amounts include a $5.4 million unrealized loss (from a decrease in revenues) on derivative contracts used to hedge forecasted crude oil sales.
(b) Includes Cortez, Central Basin, Canyon Reef Carriers, Centerline and Pecos pipeline volumes.
(c) Represents 100% of the production from the field. We own an approximately 97% working interest in the SACROC unit and an approximately 50% working interest in the Yates unit.
(d) Net to us, after royalties and outside working interests.
(e) Includes all of our crude oil production properties.
(f) Hedge gains/losses for crude oil and natural gas liquids are included with crude oil.
(g) Includes production attributable to leasehold ownership and production attributable to our ownership in processing plants and third party processing agreements.

Our 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.

As described in footnote (a) to the table above, the segment's overall decreases in both earnings before depreciation, depletion and amortization expenses and in revenues in both the three and nine months ended September 30, 2009, compared to the same periods of 2008, included a decrease of $5.4 million from an unrealized third quarter 2009 loss on derivative contracts used to hedge forecasted crude oil sales. For each of the segment's two primary businesses, the following is information related to the remaining increases and decreases, in the comparable three and nine month periods of 2009 and 2008, of the segment's (i) earnings before depreciation, depletion and amortization (EBDA); and (ii) operating revenues:

Three months ended September 30, 2009 versus Three months ended September 30, 2008

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Sales and Transportation Activities	$ (30.2)	(37)%	$ (32.6)	(35)%
Oil and Gas Producing Activities	25.5	21 %	(16.0)	(7)%
Intrasegment eliminations	-	-	11.1	51 %
Total CO_2	$ (4.7)	(2)%	$ (37.5)	(12)%

Nine months ended September 30, 2009 versus Nine months ended September 30, 2008

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Sales and Transportation Activities	$ (60.1)	(27)%	$ (58.3)	(24)%
Oil and Gas Producing Activities	9.1	2 %	(112.8)	(16)%
Intrasegment eliminations	-	-	25.7	43 %
Total CO_2	$ (51.0)	(8)%	$ (145.4)	(16)%

The segment's overall decreases in earnings before depreciation, depletion and amortization expenses in the comparable three and nine month periods of 2009 versus 2008 were primarily due to lower earnings from its sales and transportation activities. The period-to-period decreases in earnings from sales and transportation activities for the comparable three and nine month periods were mainly due to lower operating revenues, including:

- decreases of $28.7 million (42%) and $45.7 million (27%), respectively, in carbon dioxide sales revenues. The decreases were entirely price related, as the segment's average price received for all carbon dioxide sales decreased 46% and 38%, respectively, in the three and nine month periods ended September 30, 2009, when compared to last year.

  The period-to-period decreases in sales revenues resulting from unfavorable price changes more than offset increases in revenues due to higher volumes. Overall carbon dioxide sales volumes increased 9% and 17%, respectively, in 2009, primarily due to carbon dioxide expansion projects completed since the end of the third quarter last year and to a continued strong demand for carbon dioxide from tertiary oil recovery projects; and

- decreases of $3.4 million (15%) and $9.5 million (14%), respectively, in carbon dioxide and crude oil pipeline transportation revenues. The decreases were mainly due to lower carbon dioxide transportation revenues from our Central Basin Pipeline and to lower crude oil transportation revenues from our Wink Pipeline, relative to 2008. The decreases in transportation revenues from Wink were due primarily to lower pipeline loss allowance revenues resulting from lower market prices for crude oil when compared to 2008.

  The decreases in revenues from Central Basin were price related, resulting from lower weighted average transportation rates in 2009. The decreases in rates were partly due to a portion of its carbon dioxide transportation contracts being indexed to oil prices, which have dropped relative to last year, and the decreases in revenues from lower average rates more than offset increases in revenues related to transportation volume increases. Although we purchase certain volumes of carbon dioxide on an intercompany basis for use, we do not recognize profits on carbon dioxide sales to ourselves.

Earnings from the segment's oil and gas producing activities, which include the operations associated with its ownership interests in oil-producing fields and natural gas processing plants, increased $25.5 million (21%) in the third quarter of 2009 and $9.1 million (2%) in the first nine months of 2009, when compared to the same periods last year. The increases in earnings were due to the following:

- an increase of $5.1 million (3%) and a decrease of $12.5 million (2%), respectively, in crude oil sales revenues. The 3% increase in revenues in the third quarter of 2009 resulted from a corresponding 3%

increase in sales volumes, as our realized weighted average price per barrel was flat across both third quarter periods. The 2% decrease in revenues for the comparable nine month periods was entirely price related, as our realized weighted average price per barrel decreased 6% in the first nine months of 2009, when compared to the same nine month period a year ago.

The year-to-date decrease in revenues due to unfavorable pricing was partially offset by a 4% increase in crude oil sales volumes. Average gross oil production for the third quarter of 2009 was 29.6 thousand barrels per day at the SACROC unit, 6% higher compared to the third quarter of 2008. At Yates, average gross oil production for the third quarter of 2009 was 26.4 thousand barrels per day, a decline of almost 3% versus the same quarter last year;

- decreases of $19.1 million (35%) and $87.6 million (50%), respectively, in natural gas liquids sales revenues. With respect to natural gas liquids, our realized weighted average price per barrel decreased 48% and 53%, respectively, in the three and nine periods of 2009 versus 2008, but sales volumes increased 25% and 7%, respectively, in both comparable periods, due in part to the negative impacts from Hurricane Ike in the third quarter of 2008;

- decreases of $2.0 million (22%) and $12.7 million (40%), respectively, in other combined revenues, including natural gas sales, net profit interests and other service revenues. The quarterly decrease was driven by lower natural gas sales revenues in 2009, due to lower market prices for gas since the end of the third quarter of 2008, and the comparable nine month period decrease was driven by lower net profit interests revenues, which represent our share of the net proceeds from natural gas liquids, residue gas and processing fees derived from the Snyder gasoline plant;

- decreases of $26.5 million (29%) and $72.9 million (28%), respectively, in oil and gas related field operating and maintenance expenses, including all cost of sales and fuel and power expenses. The decreases were primarily due to lower prices charged by the industry's material and service providers (for items such as outside services, maintenance, and well workover services), which impacted rig costs, other materials and services, and capital and exploratory costs; and in part due to the successful renewal of lower priced service and supply contracts negotiated by our CO_2 segment since the end of the third quarter of 2008; and

- decreases of $15.0 million (74%) and $49.0 million (85%), respectively, in taxes, other than income tax expenses. The decreases were primarily due to lower period-to-period severance tax expenses—for the comparable three month periods, the decrease in severance tax expenses related to the decrease in natural gas liquids sales revenues, and for the comparable nine month periods, the decrease related to both lower liquids and crude oil sales revenues and a $20.9 million favorable adjustment to our accrued severance tax liabilities due to prior year overpayments.

Terminals

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	**2008**	**2009**	**2008**
	(In millions, except operating statistics)			
Revenues	$ 283.0	$ 306.2	$ 814.9	$ 887.1
Operating expenses(a)	(137.6)	(175.1)	(395.1)	(483.9)
Other income (expense)(b)	10.7	(4.0)	14.3	(3.6)
Earnings from equity investments	0.2	0.7	0.3	2.4
Interest income and Other, net-income (expense)	1.3	(1.3)	2.4	1.4
Income tax expense(c)	(2.4)	(6.4)	(4.0)	(17.1)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 155.2	$ 120.1	$ 432.8	$ 386.3
Bulk transload tonnage (MMtons)(d)	21.1	27.5	58.0	79.1
Liquids leaseable capacity (MMBbl)	55.6	54.2	55.6	54.2
Liquids utilization %	96.7%	98.2%	96.7%	98.2%

(a) Nine month 2009 amount includes 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. 2008 amounts include a $3.6 million increase in expense related to hurricane clean-up and repair activities, a $1.5 million increase in expense related to fire damage and repair activities, and a combined $1.5 million increase in expense associated with legal liability adjustments related to certain litigation matters involving our Elizabeth River bulk terminal and our Staten Island liquids terminal.
(b) 2009 amounts include gains of $11.3 million from hurricane and fire casualty indemnifications. 2008 amounts include losses of $5.3 million from asset write-offs related to fire damage, and losses of $0.8 million from asset write-offs related to hurricane damage.
(c) 2009 amounts include a $0.1 million increase in expense related to hurricane and fire casualty gains. 2008 amounts include a $0.4 million decrease in expense related to hurricane clean-up and repair activities and hurricane related asset write-offs.
(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.

The segment's operating results in the first nine months of 2009 include incremental contributions from strategic terminal acquisitions. Since June 2008, we have invested approximately $38.1 million in cash to acquire various terminal assets and operations, and combined, our acquired terminal operations accounted for incremental amounts of earnings before depreciation, depletion and amortization of $1.3 million, revenues of $5.2 million, and operating expenses of $3.9 million in the third quarter of 2009. For the nine month period of 2009, acquired assets contributed incremental earnings before depreciation, depletion and amortization of $3.6 million, revenues of $12.5 million, and operating expenses of $8.9 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 2009, and do not include increases or decreases during the same months we owned the assets in 2008.

For all other terminal operations (those owned during identical periods in both 2009 and 2008), the certain items described in the footnotes to the table above increased earnings before depreciation, depletion and amortization expenses for the three and nine months ended September 30, 2009 by $23.5 million and $23.9 million, respectively, when compared to the same two periods last year. The 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 $10.3 million (8%) and $19.0 million (5%) increases in earnings before depreciation, depletion and amortization; and (ii) the $28.5 million (9%) and $84.7 million (10%) decreases in operating revenues:

Three months ended September 30, 2009 versus Three months ended September 30, 2008

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Lower River (Louisiana)	$ 7.6	238 %	$ (2.7)	(11)%
Gulf Coast	4.6	14 %	4.7	11 %
Texas Petcoke	3.3	26 %	(0.4)	(1)%
Mid River	(3.0)	(36)%	(9.7)	(37)%
Ohio Valley	(2.8)	(42)%	(5.7)	(30)%
All others	0.6	1 %	(14.9)	(9)%
Intrasegment eliminations	-	-	0.2	94 %
Total Terminals	$ 10.3	8 %	$ (28.5)	(9)%

Nine months ended September 30, 2009 versus Nine months ended September 30, 2008

	EBDA increase/(decrease)			Revenues increase/(decrease)		
	(In millions, except percentages)					
Lower River (Louisiana)	$	19.4	118 %	$	(9.5)	(12)%
Gulf Coast		10.0	10 %		11.9	10 %
Texas Petcoke		4.0	9 %		(7.7)	(7)%
Mid River		(10.9)	(46) %		(31.8)	(44)%
Ohio Valley		(7.4)	(42) %		(15.6)	(31)%
All others		3.9	2 %		(32.5)	(7)%
Intrasegment eliminations		-	-		0.5	69 %
Total Terminals	$	19.0	5 %	$	(84.7)	(10)%

The increases in earnings before depreciation, depletion and amortization expenses from our Lower River (Louisiana) terminals were mainly due to (i) period-to-period decreases in income tax expenses in the three and nine months ended September 30, 2009, due to lower taxable income in many of our tax paying terminal subsidiaries; and (ii) higher earnings realized from our International Marine Terminals facility, which resulted from lower period-to-period operating expenses in 2009, and for the comparable nine month periods, from a $3.2 million property casualty gain (on a vessel dock that was damaged in March 2008) in the second quarter of 2009.

The increases in earnings from our Gulf Coast terminals reflect favorable results from our Pasadena and Galena Park, Texas liquids facilities located along the Houston Ship Channel. The earnings increases were driven by higher liquids warehousing revenues, mainly due to new and incremental customer agreements (at higher rates), additional ancillary terminal services, and to a 17% increase in total throughput volumes in the third quarter of 2009, when compared to the same quarter last year. The increase in throughput was due to both completed expansion projects and to continued strong demand for petroleum and distillate volumes.

For all liquids terminals combined, total third quarter 2009 liquids throughput volumes were 14% higher than the same quarter in 2008. Expansion projects completed since the end of the third quarter of 2008 increased our liquids terminals' leasable capacity to 55.6 million barrels, up 2.6% from a capacity of 54.2 million barrels at the end of the third quarter last year. At the same time, our overall liquids utilization capacity rate (the ratio of our actual leased capacity to our estimated potential capacity) decreased by only 1.5% since the end of the third quarter of 2008

The increases in earnings from our Texas petroleum coke operations were mainly due to the higher earnings realized in the third quarter of 2009 from our Port of Houston, Port of Beaumont and Houston Refining operations. The increases from these operations were driven by higher petroleum coke throughput and production volumes, and higher handling rates in 2009. The higher volumes in 2009 were due in part to a new petroleum coke customer contract that boosted volume at our Port of Houston bulk facility, and in part to the negative impacts caused by Hurricane Ike in the third quarter of 2008.

The overall increases in segment earnings before depreciation, depletion and amortization in the comparable three and nine month periods of 2009 and 2008 from terminals owned in both comparable periods were partly offset by lower earnings from our Mid River and Ohio Valley terminals. The decreases from these facilities were due primarily to decreased import/export activity, and to lower business activity at various owned and/or operated rail and terminal sites that are primarily involved in the handling and storage of steel and alloy products.

The economic downturn has resulted in drops in tonnage and lower period-to-period revenues and earnings at various owned or operated terminal facilities that (i) handle steel, iron ore or metals; (ii) dock barges and deep sea vessels for bulk cargo operations; or (iii) handle aggregates, phosphates or fertilizers. As a result, for our Terminals segment combined, bulk traffic tonnage decreased by 6.4 million tons (23%) in the third quarter of 2009, and decreased 21.1 million tons (27%) in the first nine months of 2009, when compared to the same prior year periods. Relatedly, revenues from terminals owned in both comparable periods decreased $28.4 million (9%) in the third quarter of 2009 and $84.9 million (10%) in the first nine months of 2009, versus the same periods of 2008.

However, while the overall volume declines have generally been broad-based across all of our bulk terminals, the rate of decline has slowed—bulk tonnage decreased 34% and 28%, respectively, in the second quarter and first six months of 2009 compared to 2008—and since the start of the year the segment has taken actions to manage costs and increase productivity. For all terminals owned in both comparable periods, combined operating expenses decreased $34.9 million (21%) in the third quarter of 2009, and decreased $90.9 million (19%) in the first nine months of 2009, versus the same periods last year. In addition to the effects from the declines in bulk tonnage volumes described above, the expense reductions were generated by a combination of aggressive cost management actions related to operating expenses, certain productivity initiatives at various terminal sites, and year-over-year declines in commodity and fuel costs.

Kinder Morgan Canada

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	**2008**	**2009**	**2008**
	(In millions, except operating statistics)			
Revenues	$ 60.1	$ 56.6	$ 166.1	$ 143.1
Operating expenses	(19.1)	(18.6)	(52.4)	(51.3)
Earnings from equity investments	(1.1)	(0.9)	(1.4)	(0.8)
Interest income and Other, net-income	10.3	3.5	19.2	9.6
Income tax benefit (expense)(a)	(2.5)	(1.0)	(17.6)	2.6
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 47.7	$ 39.6	$ 113.9	$ 103.2
Transport volumes (MMBbl)(b)	28.1	22.6	75.0	63.5

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

(b) Represents Trans Mountain pipeline system volumes.

Our Kinder Morgan Canada business segment includes the operations of the Trans Mountain, Express, and Jet Fuel pipeline systems. We acquired both our one-third equity ownership interest in the approximate 1,700-mile Express crude oil pipeline system and our full ownership of the approximate 25-mile Jet Fuel pipeline system from KMI effective August 28, 2008.

For the comparable three month periods, segment earnings before depreciation, depletion and amortization expenses increased $8.1 million (20%) in 2009 versus 2008. The quarter-to-quarter increase in segment earnings consisted of (i) higher earnings of $4.3 million (11%) from our Trans Mountain crude oil and refined products pipeline system; (ii) incremental earnings of $3.5 million from the combined operations of our Express and Jet Fuel pipeline systems during the periods we owned the assets in 2009 only (July through August); and (iii) higher earnings of $0.3 million (100%) from the combined operations of our Express and Jet Fuel pipeline systems during the period (September) we owned the assets in both years.

After taking into effect the non-cash certain items described in footnote (a) to the table above, earnings before depreciation, depletion and amortization increased $21.9 million (21%) in the first nine months of 2009 compared to the same period in 2008. The overall increase in segment earnings consisted of (i) higher earnings of $11.5 million (11%) from Trans Mountain; (ii) incremental earnings of $10.1 million from the combined Express and Jet Fuel pipeline operations during the periods we owned the assets in 2009 only (January through August); and (iii) higher earnings of $0.3 million (100%) from the combined Express and Jet Fuel pipeline operations during the period (September) we owned the assets in both years.

The period-to-period increases in earnings from Trans Mountain were driven by (i) higher pipeline transportation revenues (discussed below); and (ii) higher net currency gains from the strengthening of the Canadian dollar (included within "Other, net" income).

In the third quarter and first nine months of 2009, Trans Mountain's operating revenues increased $2.7 million (5%) and $20.7 million (14%), respectively, when compared to the same periods last year. The increases in revenues were driven by corresponding increases in mainline delivery volumes—24% in the comparable three month periods and 18% in the comparable nine month periods—resulting primarily from completed expansion projects and from significant increases in ship traffic during 2009 at the Port of Metro Vancouver. On both April 28 and October 30 of 2008, we completed separate portions of the Trans Mountain Pipeline's Anchor Loop expansion project and combined, this project boosted pipeline transportation capacity by 15% (from 260,000 barrels per day to 300,000 barrels per day) and resulted in higher period-to-period average toll rates.

Other

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(In millions-income (expense))			
General and administrative expenses(a)	$ (83.7)	$ (73.1)	$ (238.8)	$ (222.7)
Unallocable interest expense, net of interest income(b)	$ (107.8)	$ (100.5)	$ (313.7)	$ (298.1)
Unallocable income tax expense	$ (2.3)	$ (3.7)	$ (6.9)	$ (8.1)
Net income attributable to noncontrolling interests(c)	$ (4.2)	$ (3.1)	$ (11.9)	$ (11.2)

(a) Three and nine month 2009 amounts include increases in expense of $1.5 million and $4.3 million, respectively, and three and nine month 2008 amounts include increases in expense of $1.4 million and $4.2 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. Three and nine month 2009 amounts also include decreases in expense of $0.9 million and $2.4 million, respectively, related to capitalized overhead costs associated with the 2008 hurricane season, and increases in expense of $0.5 million for certain Natural Gas Pipeline asset acquisition costs, which under prior accounting standards would have been capitalized. Nine month 2009 amounts also include a $0.1 million increase in expense for certain Express pipeline system acquisition costs, which under prior accounting standards would have been capitalized. 2008 amounts also include a $0.1 million increase in expense related to hurricane clean-up and repair activities, and a $1.5 million decrease in expense due to the adjustment of certain insurance related liabilities.

(b) Three and nine month 2009 amounts include increases in imputed interest expense of $0.4 million and $1.2 million, respectively, and three and nine month 2008 amounts include increases in imputed interest expense of $0.5 million and $1.5 million, respectively, all related to our 2007 Cochin Pipeline acquisition. 2008 amounts also include a $0.2 million increase in interest expense related to the settlement of certain litigation matters related to our Pacific operations' East Line pipeline.

(c) Three and nine month 2009 amounts include a $0.1 million increase and a $0.1 million decrease, respectively, in net income attributable to noncontrolling interests, and 2008 amounts include a $0.2 million decrease in net income attributable to noncontrolling interests, all related to the combined effect of the three and nine month 2009 and 2008 items previously disclosed in the footnotes to the tables included in "—Results of Operations."

Items not attributable to any segment include general and administrative expenses, unallocable interest income and income tax expense, interest expense, and net income attributable to noncontrolling interests. Our general and administrative expenses include such items as salaries and employee-related expenses, payroll taxes, insurance, office supplies and rentals, unallocated litigation and environmental expenses, and shared corporate services—including accounting, information technology, human resources and legal services. We report our interest expense as "net," meaning that we have subtracted unallocated interest income from our total interest expense to arrive at one interest amount.

After taking into effect the certain items described in footnote (a) to the table above, our general and administrative expenses increased $9.5 million (13%) and $16.4 million (7%), respectively, in the third quarter and first nine months of 2009, when compared with the same periods of 2008. The overall increases in general and administrative expenses included increases of $2.6 million and $8.2 million, respectively, from higher employee benefit and payroll tax expenses in 2009, due mainly to cost inflation increases on work-based health and insurance benefits, higher wage rates and a larger year-over-year labor force. General and administrative expenses also increased $3.3 million and $5.8 million, respectively, due to fewer overhead expenses meeting the criteria for capitalization.

We continue to manage aggressively our general and administrative expenses, and in light of the current economic uncertainties, we have taken additional measures to reduce our expenses since the start of the year. Specifically, we are reducing our travel and compensation costs where possible, decreasing our use of outside consultants, reducing overtime where possible, and reviewing our capital and operating budgets to identify costs we can reduce without compromising operating efficiency, maintenance, or safety.

After taking into effect the certain items described in footnote (b) to the table above, our unallocable interest expense, net of interest income and capitalized interest, increased $7.6 million (8%) in the third quarter of 2009 and $16.1 million (5%) in the first nine months of 2009, versus the same periods last year. The increases in interest expense were attributable to higher average debt balances in 2009, but were partially offset by lower effective interest rates relative to 2008.

Our average borrowings for the third quarter and first nine months of 2009 increased 21% and 23%, respectively, from comparable periods in 2008. The increases were primarily due to the capital expenditures and joint venture contributions we have made since the end of the third quarter of 2008, driven primarily by continued investment in our Natural Gas Pipelines and CO_2 business segments. However, due to a general drop in variable interest rates since the end of the third quarter of 2008, the weighted average interest rate on all of our borrowings decreased 18% and 15%, respectively, in the third quarter and first nine months of 2009, when compared to the same prior-year periods. 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, 2009, approximately 52% of our $10,403.0 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 to our consolidated financial statements included elsewhere in this report.

Financial Condition

General

As of September 30, 2009, we believe our balance sheet and liquidity position remained strong. We had $168.8 million of cash and cash equivalents on hand, more than offsetting our $155.6 million short term debt balance, and we had approximately $1.4 billion of borrowing capacity available under our $1.85 billion revolving bank credit facility (discussed below in "—Short-term Liquidity"). We have consistently generated strong cash flow from operations—generating $1,377.0 million and $1,433.1 million in cash from operations in the first nine months of 2009 and 2008, respectively.

Our primary cash requirements, in addition to normal operating expenses, are 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 (resulting 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, 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, Baa2 and BBB, respectively, at Standard & Poor's, Moody's and Fitch. 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.

On September 15, 2008, Lehman Brothers Holdings Inc. filed for bankruptcy protection under the provisions of Chapter 11 of the U.S. Bankruptcy Code. Lehman Brothers Commercial Bank was a lending institution that provided $63.3 million of the commitments under our credit facility. During the first quarter of 2009, we amended our facility to remove Lehman Brothers Commercial Bank as a lender, thus reducing the facility by $63.3 million (see Note 4 "Debt" to our consolidated financial statements included elsewhere in this report). The commitments of the other banks remain unchanged, and the facility is not defaulted.

On October 13, 2008, Standard & Poor's Rating Services revised its outlook on our long-term credit rating to negative from stable (but affirmed our long-term credit rating at BBB), due to our previously announced expected delay and cost increases associated with the completion of the Rockies Express Pipeline project. At the same time, Standard and Poor's lowered our short-term credit rating to A-3 from A-2. As a result of this revision to our short-term credit rating and the current commercial paper market conditions, we are unable to access commercial paper borrowings.

On May 6, 2009, Moody's Investors Service downgraded our commercial paper rating to Prime-3 from Prime-2 and assigned a negative outlook to our long-term credit rating. The downgrade and negative outlook were primarily related to the increases, since the beginning of 2009, in our outstanding debt balance. However, we continue to maintain an investment grade credit rating, and all of our long-term credit ratings remain unchanged since December 31, 2008. Furthermore, we expect that our financing and our short-term liquidity needs will continue to be met through borrowings made under our bank credit facility. Nevertheless, our ability to satisfy our financing requirements or fund our planned capital expenditures will depend upon our future operating performance, which will be affected by prevailing economic conditions in the energy and terminals industries and other financial and business factors, some of which are beyond our control.

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

Short-term Liquidity

Our principal sources of short-term liquidity are our (i) $1.85 billion senior unsecured revolving bank credit facility that matures August 18, 2010; and (ii) cash from operations (discussed below in "—Operating Activities"). Borrowings under our bank credit facility can be used for general partnership purposes and as a backup for our commercial paper program. The facility can be amended to allow for borrowings of up to $2.04 billion (after reductions for the lending commitments made by Lehman Brothers Commercial Bank, which were canceled in connection with the Lehman Brothers bankruptcy and discussed above in "—Credit Ratings and Capital Market Liquidity"). We plan to negotiate a renewal of the credit facility before its maturity date. As of September 30, 2009, the outstanding balance under our bank credit facility was $110.0 million, and there were no borrowings under our commercial paper program. As of December 31, 2008, we had no outstanding borrowings under our credit facility or our commercial paper program.

We provide for additional liquidity by maintaining a sizable amount of excess borrowing capacity related to our bank credit facility. After reduction for (i) our letters of credit; (ii) our outstanding borrowings under our credit facility; and (iii) the lending commitments made by Lehman Brothers Commercial Bank, the remaining available borrowing capacity under our bank credit facility was $1,412.5 million as of September 30, 2009. This remaining borrowing capacity allows us to manage our day-to-day cash requirements and any anticipated obligations and currently, we believe our liquidity to be adequate.

Working capital—current assets minus current liabilities—can also be used to measure how much in liquid assets a company has available to build its business, and we had working capital deficits of $142.2 million as of September 30, 2009 and $537.7 million as of December 31, 2008. The favorable change from year-end 2008 was primarily due to higher net receivables and payables (including receivables for the value of natural gas inventory stored in our underground storage facilities), lower short-term debt obligations and increased cash balances.

Generally, our working capital balance varies due to factors such as the timing of scheduled debt payments, timing differences in the collection and payment of receivables and payables, the change in fair value of our derivative contracts and changes in cash and cash equivalent balances as a result of debt or equity issuances (discussed below in "—Long-term Financing"). As a result, our working capital balance could return to a surplus in future periods. A working capital deficit is not unusual for us or for other companies similar in size and scope to us, and we believe that our working capital deficit does not indicate a lack of liquidity as we continue to maintain adequate current assets to satisfy current liabilities and maturing obligations when they come due.

Long-term Financing

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

We are subject, however, to conditions in the equity and debt markets for our limited partner units and long-term 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 notes in the future. If we were unable or unwilling to issue additional limited partner units, we would be required to either restrict potential future acquisitions or pursue debt financing alternatives, some of which could involve higher costs or negatively affect our credit ratings. Furthermore, our ability to access the public and private debt markets is affected by our credit ratings. See "—Credit Ratings and Capital Market Liquidity" above for a discussion of our credit ratings.

As of September 30, 2009 and December 31, 2008, the total liability balance due on the various series of our senior notes was $10,124.6 million and $8,381.5 million, respectively, and the total liability balance due on the various borrowings of our operating partnerships and subsidiaries was $168.4 million and $182.1 million, respectively. For more information on our 2009 debt related transactions, including our issuances of senior notes, see Note 4 "Debt" to our consolidated financial statements included elsewhere in this report, and for additional information regarding our debt securities and credit facility, see Note 9 to our consolidated financial statements included in our 2008 Form 10-K. For information on our 2009 equity issuances, including cash proceeds received from both public offerings of common units and our equity distribution agreement, see Note 5 "Partners' Capital—Equity Issuances" to our consolidated financial statements included elsewhere in this report.

Capital Structure

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

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

Capital Expenditures

Including both sustaining and discretionary spending, our capital expenditures were $1,075.4 million in the first nine months of 2009, versus $1,914.4 million in the same year-ago period. Our sustaining capital expenditures, defined as capital expenditures which do not increase the capacity of an asset, totaled $112.0 million, compared to $120.1 million for 2008. These sustaining expenditure amounts include our proportionate share of Rockies Express' sustaining capital expenditures—approximately $0.2 million in the first nine months of 2009 and less than $0.1 million in the first nine months of 2008. Additionally, our forecasted expenditures for the remaining three months of 2009 for sustaining capital expenditures are approximately $64.2 million—including our proportionate shares of Rockies Express and Midcontinent Express. Generally, we fund our sustaining capital expenditures with existing cash or from cash flows from operations. In addition to utilizing cash generated from its operations, Rockies Express can fund its cash requirements for capital expenditures through borrowings under its own credit facility, issuing its own long-term notes, or with proceeds from contributions received from its equity owners.

All of our capital expenditures, with the exception of sustaining capital expenditures, are classified as discretionary. The discretionary capital expenditures reflected in our consolidated statement of cash flows for the first nine months of 2009 and 2008 were $963.6 million and $1,794.3 million, respectively. The period-to-period decrease in discretionary capital expenditures was mainly due to higher capital expenditures made during 2008 on our major natural gas pipeline projects. Generally, we fund our discretionary capital expenditures (and our investment contributions) through borrowings under our bank credit facility. To the extent this source of funding is not sufficient, we generally fund additional amounts through the issuance of long-term notes or common units for cash. During the first nine months of 2009, we used sales of common units and the issuance of senior notes to refinance portions of our short-term borrowings under our bank credit facility.

Operating Activities

Net cash provided by operating activities was $1,377.0 million for the nine months ended September 30, 2009, versus $1,433.1 million for the comparable period of 2008. The period-to-period decrease of $56.1 million (4%) in cash provided by operating activities primarily consisted of:

- a $210.4 million decrease in cash inflows relative to net changes in working capital items, primarily driven by higher payments in 2009 for (i) natural gas storage on our Kinder Morgan Texas Pipeline system; (ii) the settlement of certain refined products imbalance liabilities owed to U.S. military customers of our Products Pipelines business segment; (iii) employee-related bonus and general partner incentive funding; and (iv) reductions in customer deposits;

- a combined $49.1 million decrease in cash from (i) undistributed earnings from equity investees; (ii) income from the allowance for equity funds used during construction; and (iii) income from the dispositions of property, plant and equipment and other net assets;

- a $144.4 million increase in cash from an interest rate swap termination payment we received in January 2009, when we terminated a fixed-to-variable interest rate swap agreement having a notional principal amount of $300 million and a maturity date of March 15, 2031;

- a $37.8 million increase in cash related to higher distributions received from equity investments during the first nine months of 2009—chiefly due to incremental distributions of $41.8 million received from West2East Pipeline LLC, the sole owner of Rockies Express Pipeline LLC. We began receiving distributions on our 51% equity interest in West2East Pipeline LLC in the second quarter of 2008. When construction of the Rockies Express Pipeline is completed, our ownership interest will be reduced to 50% and the capital accounts of West2East Pipeline LLC will be trued-up to reflect our 50% economic interest in the project; and

- a $34.9 million increase in cash from overall lower partnership income—after adjusting for depreciation, depletion and amortization expenses. The year-to-year increase in partnership income from our five reportable business segments in the first nine months of 2009 compared to the first nine months of 2008 is discussed above in "—Results of Operations" (including all of the certain items disclosed in the associated table footnotes).

Investing Activities

Net cash used in investing activities was $2,616.5 million for the nine month period ended September 30, 2009, compared to $2,065.9 million for the comparable 2008 period. The $550.6 million (27%) increase in cash used in investing activities was primarily attributable to:

- a $1,277.5 million increase in cash used due to higher contributions to equity investees in the first nine months of 2009, relative to the first nine months a year ago. The increase was primarily driven by incremental contributions to West2East Pipeline LLC, Midcontinent Express Pipeline LLC, and Fayetteville Pipeline LLC to partially fund both their respective Rockies Express, Midcontinent Express, and Fayetteville Express Pipeline construction and/or pre-construction costs, and the repayment of senior notes by Rockies Express in August 2009. As discussed in Note 2 to our interim consolidated financial statements included elsewhere in this report, we contributed a combined $1,610.3 million during the first nine months of 2009 for these three pipeline projects. During the same period last year, we contributed a combined $333.5 million to partially fund our proportionate share of the Rockies Express and Midcontinent Express pipeline construction costs;

- an $89.1 million increase in cash used related to a return of capital received from Midcontinent Express Pipeline LLC in February 2008. During that month, Midcontinent entered into and then made borrowings under a new $1.4 billion three-year, unsecured revolving credit facility due February 28, 2011. Midcontinent then made distributions (in excess of cumulative earnings) to its two member owners to reimburse them for prior contributions made to fund its pipeline construction costs;

- a $53.5 million increase in cash used due to higher period-to-period payments for margin and restricted deposits in 2009 compared to 2008, associated largely with our utilization of derivative contracts to hedge (offset) against the volatility of energy commodity price risks;

- a $41.9 million increase in cash used for the acquisition of assets, relative to 2008. The increase was driven by the $18.0 million we paid to acquire certain terminal assets from Megafleet Towing Co., Inc. in April 2009 (discussed in Note 2) and the $23.4 million contribution we received from KMI in April 2008 as a result of certain true-up provisions in our Trans Mountain acquisition agreement;

- an $839.0 million decrease in cash used for capital expenditures—largely due to the higher investment undertaken in the first nine months of 2008 to construct our Kinder Morgan Louisiana Pipeline and to expand our Trans Mountain crude oil and refined petroleum products pipeline system; and

- a $109.6 million decrease in cash used due to our receipt, in the first nine months of 2009, of the full repayment of a $109.6 million 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 $1,340.8 million for the first nine months of 2009. For the first nine months a year ago, our financing activities provided net cash of $629.7 million. The increase in cash provided by financing activities of $711.1 million (113%) from the comparable 2008 period was mainly due to:

- a $564.2 million increase in cash from overall debt financing activities—which include our issuances and payments of debt and our debt issuance costs. The period-to-period increase in cash from overall financing activities was primarily due to (i) a $148.9 million increase in cash due to higher net issuances and repayments of senior notes in the first nine months of 2009; (ii) a $589.1 million increase in cash due to net commercial paper repayments in the first nine months of 2008; and (iii) a $185.0 million decrease in cash from lower net borrowings under our bank credit facility in the first nine months of 2009;

  The period-to-period increases and decreases in cash inflows from our commercial paper and credit facility borrowings were related to our short-term credit rating downgrade discussed above in "—Credit Ratings and Capital Market Liquidity". The increase in cash inflows from changes in senior notes outstanding reflects the combined $1,730.7 million we received from both issuing and repaying senior notes in 2009 (discussed in Note 4 to our interim consolidated financial statements included elsewhere in this report), versus the combined $1,581.8 million we received from our February and June 2008 public offerings of senior notes. We used the proceeds from each of these offerings to reduce the borrowings under our commercial paper program;

- a $431.2 million increase in cash from higher partnership equity issuances. The increase relates to the combined $815.5 million we received, after commissions and underwriting expenses, from the sales of additional common units in the first nine months of 2009 (discussed in Note 5 to our consolidated financial statements included elsewhere in this report), versus the combined $384.3 million we received from two separate offerings of common units in the first nine months of 2008. The $384.3 million in proceeds received in 2008 included $60.1 million from the issuance of 1,080,000 common units in a privately negotiated transaction completed in February 2008, and $324.2 million from the issuance of 5,750,000 additional common units pursuant to a public offering completed in March 2008. We used the proceeds from these offerings to reduce the borrowings under our commercial paper program;

- a $223.9 million decrease in cash due to higher partnership distributions paid in the first nine months of 2009, when compared to the same period last year. The increase in distributions to all partners, including our common and Class B unitholders, our general partner and our noncontrolling interests, was due to an increase in the per unit cash distributions paid, an increase in the number of units outstanding, and an increase in our general partner incentive distributions. The increase in our general partner incentive distributions resulted from both increased cash distributions per unit and an increase in the number of common units and i-units outstanding. Further information regarding our distributions is included below in "—Partnership Distributions;" and

- a $61.3 million decrease in cash inflows from net changes in cash book overdrafts—resulting from timing differences on checks issued but not yet presented for payment.

Partnership Distributions

Our partnership agreement requires that we distribute 100% of "Available Cash," as defined in our partnership agreement, to our partners within 45 days following the end of each calendar quarter in accordance with their respective percentage interests. Our 2008 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 14, 2009, we paid a quarterly distribution of $1.05 per unit for the second quarter of 2009. This distribution was 6% greater than the $0.99 distribution per unit we paid in August 2008 for the second quarter of 2008. We paid this distribution in cash to our general partner and to our common and Class B unitholders. KMR, our sole i-unitholder, received additional i-units based on the $1.05 cash distribution per common unit. On October

21, 2009, we declared a cash distribution of $1.05 per unit for the third quarter of 2009 (an annualized rate of $4.20 per unit). This distribution was 3% higher than the $1.02 per unit distribution we made for the third quarter of 2008.

The incentive distribution that we paid on August 14, 2009 to our general partner (for the second quarter of 2009) was $231.8 million. Our general partner's incentive distribution that we paid in August 2008 (for the second quarter of 2008) was $194.2 million. Our general partner's incentive distribution for the distribution that we declared for the third quarter of 2009 is $235.0 million, and our general partner's incentive distribution for the distribution that we paid for the third quarter of 2008 was $204.3 million. The period-to-period increases in our general partner incentive distributions resulted from both increased cash distributions per unit and increases in the number of common units and i-units outstanding.

Additionally, in November 2008, we announced that we expected to declare cash distributions of $4.20 per unit for 2009, almost a 4.5% increase over our cash distribution of $4.02 per unit for 2008. 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. 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. Our 2009 distribution expectation assumes an average West Texas Intermediate crude oil price of $68 per barrel (with some minor adjustments for timing, quality and location differences). 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 2009 budget), we currently expect to realize an average WTI crude oil price of approximately $60 per barrel in 2009. For 2009, we expect that every $1 change in the average WTI crude oil price per barrel will impact our CO_2 segment's cash flows by approximately $6 million (or approximately 0.2% of our combined business segments' distributable cash flow).

To offset the lower crude prices, as well as other headwinds we face from ongoing weak market conditions, we have identified a number of areas across our company to minimize costs and maximize revenues without compromising operational safety or efficiency. Since the start of 2009, (i) we have continued to focus on reducing our general and administrative expenses across our business portfolio wherever possible; (ii) our CO_2 business segment has negotiated lower contract prices with various oil and gas material and service suppliers, thereby lowering its operating and maintenance expenses; (iii) our Terminals segment has entered into various term supply contracts to lower its costs for diesel fuel; and (iv) average interest rates have been lower than originally anticipated for 2009, resulting in lower interest expense on our outstanding debt. We expect these items to further benefit us throughout the remaining three months of the year, and as a result of these cost reductions and other opportunities that we have identified, we continue to expect that we will achieve our budget target of $4.20 per unit in cash distributions for 2009.

Recent Accounting Pronouncements

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

Information Regarding Forward-Looking Statements

This filing 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 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 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 2008 Form 10-K for a more detailed description of these and other factors that may affect the forward-looking statements. When considering forward-looking statements, one should keep in mind the risk factors described in our 2008 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, 2008, in Item 7A of our 2008 Form 10-K. For more information on our risk management activities, see Note 6 to our consolidated financial statements included elsewhere in this report.

Item 4. Controls and Procedures.

As of September 30, 2009, 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, 2009 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

See Part I, Item 1, Note 10 to our consolidated financial statements entitled "Litigation, Environmental and Other Contingencies," which is incorporated in this item by reference.

Item 1A. Risk Factors.

There have been no material changes in or additions to the risk factors disclosed in Part I, Item 1A "Risk Factors" in our 2008 Form 10-K.

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

None.

Item 3. Defaults Upon Senior Securities.

None.

Item 4. Submission of Matters to a Vote of Security Holders.

None.

Item 5. Other Information.

None.

Item 6. Exhibits.

4.1 — Certain instruments with respect to long-term debt of Kinder Morgan Energy Partners, L.P. and its consolidated subsidiaries which relate to debt that does not exceed 10% of the total assets of Kinder Morgan Energy Partners, L.P. and its consolidated subsidiaries are omitted pursuant to Item 601(b) (4) (iii) (A) of Regulation S-K, 17 C.F.R. sec.229.601. Kinder Morgan Energy Partners, L.P. hereby agrees to furnish supplementally to the Securities and Exchange Commission a copy of each such instrument upon request.

4.2 — Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 5.80% Senior Notes due 2021, and the 6.50% Senior Notes due 2039.

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, 2009 and 2008; (ii) our Consolidated Balance Sheets as of September 30, 2009 and December 31, 2008; (iii) our Consolidated Statements of Cash Flows for the nine months ended September 30, 2009 and 2008; and (iv) the notes to our Consolidated Financial Statements, tagged as blocks of text.

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 30, 2009

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