F O R M 10-Q

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

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

For the quarterly period ended **March 31, 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 [ ] 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 189,356,462 common units outstanding as of April 30, 2009.

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

Item 1. Financial Statements.

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

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
Revenues		
Natural gas sales	$ 888.7	$ 1,721.2
Services	661.4	675.7
Product sales and other	236.4	323.4
	1,786.5	2,720.3
Costs, Expenses and Other		
Gas purchases and other costs of sales	865.7	1,732.1
Operations and maintenance	200.6	223.1
Fuel and power	49.4	63.3
Depreciation, depletion and amortization	210.2	158.1
General and administrative	82.5	76.8
Taxes, other than income taxes	39.0	48.0
Other expense (income)	(0.9)	(0.5)
	1,446.5	2,300.9
Operating Income	340.0	419.4
Other Income (Expense)		
Earnings from equity investments	38.2	37.7
Amortization of excess cost of equity investments	(1.4)	(1.4)
Interest, net	(97.2)	(96.7)
Other, net	10.7	2.9
Income from Continuing Operations Before Income Taxes	290.3	361.9
Income Taxes	(23.5)	(11.7)
Income from Continuing Operations	266.8	350.2
Discontinued Operations (Note 2):		
Adjustment to gain on disposal of North System	—	0.5
Income from Discontinued Operations	—	0.5
Net Income	266.8	350.7
Net Income attributable to the noncontrolling interest	(2.9)	(4.0)
Net Income attributable to Kinder Morgan Energy Partners, L.P.	$ 263.9	$ 346.7
Calculation of Limited Partners' interest in Net Income		
Amounts attributable to Kinder Morgan Energy Partners L.P.:		
Income from Continuing Operations	$ 263.9	$ 346.2
Less: General Partner's interest	(223.7)	(187.4)
Limited Partners' interest	40.2	158.8
Add: Limited Partners' interest in Discontinued Operations	—	0.5
Limited Partners' interest in Net Income	$ 40.2	$ 159.3
Basic and Diluted Limited Partners' Net Income per Unit:		
Income from Continuing Operations	$ 0.15	$ 0.63
Income from Discontinued Operations	—	—
Net Income	$ 0.15	$ 0.63
Basic and Diluted weighted average number of units used in computation of Limited Partners' Net Income per unit	269.4	251.0
Per unit cash distribution declared	$ 1.05	$ 0.96

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)

	March 31, 2009	December 31, 2008
ASSETS		
Current Assets		
Cash and cash equivalents	$ 65.5	$ 62.5
Restricted deposits	3.3	—
Accounts, notes and interest receivable, net		
Trade	665.3	978.9
Related parties	8.7	9.0
Inventories		
Products	21.6	16.2
Materials and supplies	26.7	28.0
Gas imbalances		
Trade	5.9	14.1
Related parties	—	—
Gas in underground storage	18.2	—
Other current assets	136.7	135.7
	951.9	1,244.4
Property, Plant and Equipment, net	13,356.9	13,241.4
Investments	1,101.2	954.3
Notes receivable		
Trade	0.3	—
Related parties	174.9	178.1
Goodwill	1,052.0	1,058.9
Other intangibles, net	202.3	205.8
Deferred charges and other assets	742.2	1,002.9
Total Assets	$ 17,581.7	$ 17,885.8
LIABILITIES AND PARTNERS' CAPITAL		
Current Liabilities		
Accounts payable		
Cash book overdrafts	$ 39.9	$ 42.8
Trade	506.3	831.0
Related parties	27.7	24.6
Current portion of long-term debt	484.9	288.7
Accrued interest	85.7	172.3
Accrued taxes	68.7	51.9
Deferred revenues	25.8	41.1
Gas imbalances		
Trade	4.5	10.2
Related parties	7.7	2.2
Accrued other current liabilities	288.3	317.3
	1,539.5	1,782.1
Long-Term Liabilities and Deferred Credits		
Long-term debt		
Outstanding	8,257.8	8,274.9
Value of interest rate swaps	814.6	951.3
	9,072.4	9,226.2
Deferred revenues	12.1	12.9
Deferred income taxes	177.7	178.0
Asset retirement obligations	82.9	74.0
Other long-term liabilities and deferred credits	480.0	496.3
	9,825.1	9,987.4
Total Liabilities	11,364.6	11,769.5
Commitments and Contingencies (Note 3)		
Partners' Capital		
Common Units	3,584.9	3,458.9
Class B Units	89.3	94.0
i-Units	2,590.0	2,577.1
General Partner	207.6	203.3
Accumulated other comprehensive loss	(326.3)	(287.7)
Total Kinder Morgan Energy Partners, L.P. Partners' Capital	6,145.5	6,045.6
Noncontrolling interest	71.6	70.7
Total Partners' Capital	6,217.1	6,116.3
Total Liabilities and Partners' Capital	$ 17,581.7	$ 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
(Increase/(Decrease) in Cash and Cash Equivalents in Millions)
(Unaudited)

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
Cash Flows From Operating Activities		
Net Income	$ 266.8	$ 350.7
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	210.2	158.1
Amortization of excess cost of equity investments	1.4	1.4
Income from the allowance for equity funds used during construction	(9.3)	—
Income from the sale of property, plant and equipment	(0.9)	(0.9)
Earnings from equity investments	(38.2)	(37.7)
Distributions from equity investments	56.5	24.1
Proceeds from termination of interest rate swap agreements	144.4	—
Changes in components of working capital:		
Accounts receivable	210.6	(121.4)
Other current assets	3.3	(33.0)
Inventories	(4.3)	(1.5)
Accounts payable	(246.9)	66.0
Accrued interest	(86.5)	(66.7)
Accrued liabilities	(56.6)	1.8
Accrued taxes	16.7	1.2
Rate reparations, refunds and other litigation reserve adjustments	—	(23.3)
Other, net	(14.8)	(11.9)
Net Cash Provided by Operating Activities	452.4	306.9
Cash Flows From Investing Activities		
Acquisitions of assets	(0.5)	(0.3)
Repayments from customers	98.1	—
Additions to property, plant and equip. for expansion and maintenance projects	(420.3)	(628.1)
Sale of property, plant and equipment, and other net assets net of removal costs	(1.4)	(4.2)
Investments in margin deposits	(5.8)	(98.8)
Contributions to equity investments	(173.5)	(336.0)
Distributions from equity investments	—	89.1
Natural gas stored underground and natural gas liquids line-fill	—	(2.7)
Net Cash Used in Investing Activities	(503.4)	(981.0)
Cash Flows From Financing Activities		
Issuance of debt	913.8	2,746.3
Payment of debt	(725.7)	(2,141.1)
Repayments from related party	1.2	—
Debt issue costs	(0.4)	(5.8)
Increase (Decrease) in cash book overdrafts	(2.9)	39.0
Proceeds from issuance of common units	287.9	384.3
Contributions from noncontrolling interest	3.8	4.8
Distributions to partners and noncontrolling interest:		
Common units	(192.3)	(156.6)
Class B units	(5.6)	(4.9)
General Partner	(219.4)	(172.6)
Noncontrolling interest	(5.4)	(4.2)
Other, net	(0.1)	—
Net Cash Provided by Financing Activities	54.9	689.2
Effect of exchange rate changes on cash and cash equivalents	(0.9)	(0.7)
Increase in Cash and Cash Equivalents	3.0	14.4
Cash and Cash Equivalents, beginning of period	62.5	58.9
Cash and Cash Equivalents, end of period	$ 65.5	$ 73.3
Noncash Investing and Financing Activities:		
Assets acquired by the assumption or incurrence of liabilities	$ —	$ 0.3

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

1. Organization

General

Unless the context requires otherwise, references to "we," "us," "our" or the "Partnership" are intended to mean Kinder Morgan Energy Partners, L.P. and its consolidated subsidiaries. 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. You should read these consolidated financial statements in conjunction with our consolidated financial statements and related notes 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.

Knight Inc. (formerly known as Kinder Morgan, Inc.), Kinder Morgan G.P., Inc. and Kinder Morgan Management, LLC

Knight Inc., referred to as "Knight" in this report, is a private company 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). Additional investors in Knight include, among others, certain members of Knight's senior management, most of whom are also senior officers of our general partner and of its delegate. Before completing its going-private transaction on May 30, 2007, and subsequently being renamed, Knight was known as Kinder Morgan, Inc., a Kansas corporation referred to as "KMI" in this report.

Knight 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

Our consolidated financial statements include our accounts and those of our operating partnerships and their majority-owned and controlled subsidiaries. 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$. All significant intercompany items have been eliminated in consolidation.

Our accompanying consolidated financial statements reflect amounts on a historical cost basis, and, accordingly, do not reflect any purchase accounting adjustments related to the May 30, 2007 going-private transaction of KMI, now known as Knight. Certain amounts from prior periods have been reclassified to conform to the current presentation.

Also, prior to the third quarter of 2008, we reported five business segments: Products Pipelines; Natural Gas Pipelines; CO_2; Terminals; and Trans Mountain. On August 28, 2008, we acquired from Knight a one-third interest in the Express pipeline system and the Jet Fuel pipeline system, and following the acquisition of these businesses, the operations of our Trans Mountain, Express and Jet Fuel pipeline systems have been combined to represent the "Kinder Morgan Canada" segment. For more information on our reportable business segments, see Note 12.

Net Income Per Unit

We compute Basic 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. Diluted Limited Partners' Net Income per Unit reflects the maximum potential dilution that could occur if units whose issuance depends on the market price of the units at a future date were considered outstanding, or if, by application of the treasury stock method, options to issue units were exercised, both of which would result in the issuance of additional units that would then share in our allocation of net income. See Note 16 for further information regarding recent accounting pronouncements relating to earnings per unit.

2. Acquisitions, Joint Ventures and Divestitures

Acquisitions

During the first quarter of 2009, we did not enter into any new business acquisitions or any new joint ventures, and we did not record any material purchase price adjustments related to our previously completed acquisitions. 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.

Joint Ventures

In the first quarter of 2009, we made capital contributions of $111.0 million to Midcontinent Express Pipeline LLC and $51.0 million to West2East Pipeline LLC (the sole owner of Rockies Express Pipeline LLC) to partially fund construction costs for the Midcontinent Express and the Rockies Express natural gas pipeline systems, respectively. We also made a $9.0 million capital contribution to Fayetteville Express Pipeline LLC in the first quarter of 2009 to partially fund certain pre-construction pipeline costs for the Fayetteville Express Pipeline. We included all of these cash contributions as increases to "Investments" in our accompanying consolidated balance sheet as of March 31, 2009, and as "Contributions to equity investments" in our accompanying consolidated statement of cash flows for the three months ended March 31, 2009. We own a 50% equity interest in Midcontinent Express Pipeline LLC, a 51% equity interest in West2East Pipeline LLC, and a 50% equity interest in Fayetteville Express Pipeline LLC.

We also received, in the first quarter of 2008, an $89.1 million return of capital from Midcontinent Express Pipeline LLC. In February 2008, Midcontinent entered into and 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, and we reflected this cash receipt separately as "Distributions from equity investments" in the investing section of our accompanying consolidated statement of cash flows for the three months ended March 31, 2008.

Divestitures

On July 2, 2007, we announced that we entered into an agreement to sell the 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) to ONEOK Partners, L.P. for approximately $298.6 million in cash. Our investment in net assets, including all transaction related accruals, was approximately $145.8 million, most of which represented property, plant and equipment, and we recognized approximately $152.8 million of gain in the fourth quarter of 2007 from the sale of these net assets. In accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," we accounted for the North System business as a discontinued operation whereby the financial results and the gains on disposal of the North System are reclassified to discontinued operations in our consolidated statements of income. Prior to the sale, all of the assets were included in our Products Pipelines business segment.

In the first quarter of 2008, we paid a net amount of $2.4 million to ONEOK to partially settle the sale of working capital items, the allocation of pre-acquisition investee distributions, and the sale of liquids inventory balances. We recognized an additional $0.5 million gain, primarily based upon these adjustments, and we reported this gain within the caption "Adjustment to gain on disposal of North System" within the discontinued operations section of our accompanying consolidated statement of income for the three months ended March 31, 2008. Except for this gain, we recorded no other financial results from the operations of the North System during the first quarter of 2008.

In our accompanying consolidated statement of cash flows, and in our segment disclosures, we elected not to separately present as discontinued operations the sale of the North System. This election was made because the sale of the North System does not change the structure of our internal organization in a manner that causes a change to our reportable business segments. This is consistent with the provisions of SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information."

Acquisition Subsequent to March 31, 2009

On April 23, 2009, we acquired certain terminal assets and operations from Megafleet Towing Co., Inc. for an aggregate consideration of approximately $23.0 million, consisting of $18.0 million in cash and a contingent obligation to pay an additional $5 million in cash on April 23, 2014, five years from closing. The contingent obligation will be recorded at its fair value, and is based upon the purchased assets providing us an agreed-upon amount of earnings during the five year period. The acquired assets primarily consist of nine marine vessels that provide towing and harbor boat services in the Gulf coastal area, the intracoastal waterways, 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 will allocate our total purchase price to assets acquired and liabilities assumed in the second quarter of 2009.

3. Litigation, Environmental and Other Contingencies

Below is a brief description of our ongoing material legal proceedings, including any material developments that occurred in such proceedings during the three months ended March 31, 2009. Additional information with respect to these proceedings can be found in Note 16 to our audited 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 three months ended March 31, 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; Mobil Oil Corporation as Mobil; ExxonMobil Oil Corporation as ExxonMobil; Tosco Corporation as Tosco; ConocoPhillips Company as ConocoPhillips; 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 Airline Complainants; and the Federal Energy Regulatory Commission, as the FERC.

Federal Energy Regulatory Commission Proceedings

▪ FERC Docket No. OR92-8, et al.—Complainants/Protestants: Chevron, Navajo, ARCO, BP WCP, Western Refining, ExxonMobil, Tosco, and Texaco (Ultramar is an intervenor)—Defendant: SFPP; 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;

- FERC Docket No. OR96-2, et al.—Complainants/Protestants: All Shippers except Chevron (which is an intervenor)—Defendant: SFPP—Subject: Complaints against all SFPP rates;

- FERC Docket Nos. OR02-4 and OR03-5—Complainant/Protestant: Chevron—Defendant: SFPP; FERC Docket No. OR04-3—Complainants/Protestants: America West Airlines, Southwest Airlines, Northwest Airlines, and Continental Airlines—Defendant: SFPP; FERC Docket Nos. OR03-5, OR05-4 and OR05-5—Complainants/Protestants: BP WCP, ExxonMobil, and ConocoPhillips (other shippers intervened)—Defendant: SFPP—Subject: Complaints against all SFPP rates; OR02-4 was dismissed and Chevron appeal pending at U.S. Court of Appeals for D.C. Circuit, referred to in this report as D.C. Circuit;

- 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 Knight Inc.—Subject: Complaints against all SFPP rates; held in abeyance; complaint withdrawn as to SFPP's affiliates;

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

- FERC Docket Nos. OR07-8 and OR07-11 (consolidated)—Complainants/Protestants: BP WCP and ExxonMobil —Defendant: SFPP—Subject: Complaints against SFPP 2005 index rates; settled in 2008;

- FERC Docket No. OR07-9—Complainant/Protestant: BP WCP—Defendant: SFPP—Subject: Complaint against ultra low sulfur diesel surcharge; dismissed by FERC; BP WCP appeal dismissed by D.C. Circuit;

- FERC Docket No. OR07-14—Complainants/Protestants: BP WCP and Chevron—Defendants: SFPP, Calnev, and several affiliates—Subject: Complaint against cash management practices; dismissed by FERC;

- FERC Docket No. OR07-16—Complainant/Protestant: Tesoro—Defendant: Calnev—Subject: Complaint against Calnev 2005, 2006 and 2007 indexed rate increases; dismissed by FERC; Tesoro appeal dismissed by D.C. Circuit;

- FERC Docket Nos. OR07-18, OR07-19 & OR07-22—Complainants/Protestants: Airline Complainants, 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. IS05-327—Complainants/Protestants: Shippers—Defendant: SFPP—Subject: 2005 indexed rate increases; protests dismissed by FERC; appeal dismissed by D.C. Circuit;

- FERC Docket Nos. IS06-283, IS06-356, IS08-28 and IS08-302—Complainants/Protestants: Shippers—Defendant: SFPP—Subject: East Line expansion rate increases; settled;

- FERC Docket Nos. IS06-356, IS07-229 and IS08-302—Complainants/Protestants: Shippers—Defendant: SFPP—Subject: 2006, 2007 and 2008 indexed rate increases; protests dismissed by FERC; East Line rates resolved by East Line settlement;

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

- FERC Docket No. IS07-234—Complainants/Protestants: BP WCP and ExxonMobil—Defendant: Calnev—Subject: 2007 indexed rate increases; protests dismissed by FERC;

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

- Motions to compel payment of interim damages (various dockets)—Complainants/Protestants: Shippers—Defendants: SFPP, Kinder Morgan G.P., Inc., and Knight Inc.; Motion for resolution on the merits (various dockets)—Complainants/Protestants: BP WCP and ExxonMobil—Defendant: SFPP and Calnev.

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 2008. 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. Upon the finality of FERC's approval, reduced settlement rates are expected to go into effect on May 1, 2009, and SFPP will make refunds and settlement payments shortly thereafter, estimated to total approximately $16.0 million.

Based on our review of these FERC proceedings, we estimate that as of March 31, 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 third quarter of 2009.

California Public Utilities Commission Proceedings

SFPP has previously reported ratemaking proceedings pending with the California Public Utilities Commission, referred to in this note as the CPUC. The complaints generally challenge 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 previously untariffed charges for certain pipeline transportation and related services. All of these matters have been consolidated and assigned to a single administrative law judge. At the time of this report, it is unknown when a decision from the CPUC regarding these matters will be received. 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, 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 are asserting 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. have also asserted 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 were dismissed with prejudice. The court entered final judgment in favor of 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, successor to Shell CO_2 Company, Ltd., 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 continues 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 Notice of Noncompliance and Civil Penalty

On December 20, 2006, Kinder Morgan CO_2 received a "Notice of Noncompliance and Civil Penalty: Knowing or Willful Submission of False, Inaccurate, or Misleading Information—Kinder Morgan CO_2 Company, L.P., Case No. CP07-001" from the U.S. Department of the Interior, Minerals Management Service, referred to in this note as the MMS. This Notice, and the MMS's position that Kinder Morgan CO_2 has violated certain reporting obligations, relates to a disagreement between the MMS and Kinder Morgan CO_2 concerning the approved transportation allowance to be used in valuing McElmo Dome carbon dioxide for purposes of calculating federal royalties.

The Notice of Noncompliance and Civil Penalty assesses a civil penalty of approximately $2.2 million as of December 15, 2006 (based on a penalty of $500.00 per day for each of 17 alleged violations) for Kinder Morgan CO_2's alleged submission of false, inaccurate, or misleading information relating to the transportation allowance, and federal royalties for carbon dioxide produced at McElmo Dome, during the period from June 2005 through October 2006. The MMS stated that civil penalties will continue to accrue at the same rate until the alleged violations are corrected.

The parties have reached a settlement of the Notice of Noncompliance and Civil Penalty. 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.

MMS Order to Report and Pay

On March 20, 2007, Kinder Morgan CO_2 received an "Order to Report and Pay" from the MMS. The MMS contends that Kinder Morgan CO_2 has over-reported transportation allowances and underpaid royalties in the amount of approximately $4.6 million for the period from January 1, 2005 through December 31, 2006 as a result of its use of the Cortez Pipeline tariff as the transportation allowance in calculating federal royalties. The MMS claims that the Cortez Pipeline tariff is not the proper transportation allowance and that Kinder Morgan CO_2 must use its "reasonable actual costs" calculated in accordance with certain federal product valuation regulations. The MMS set a due date of April 13, 2007 for Kinder Morgan CO_2's payment of the $4.6 million in claimed additional royalties, with possible late payment charges and civil penalties for failure to pay the assessed amount.

Kinder Morgan CO_2 has not paid the $4.6 million, and on April 19, 2007, it submitted a notice of appeal and statement of reasons in response to the Order to Report and Pay, challenging the Order and appealing it to the Director of the MMS in accordance with 30 C.F.R. sec. 290.100, et seq.

In addition to the March 2007 Order to Report and Pay, in April 2007, Kinder Morgan CO_2 received an "Audit Issue Letter" sent by the Colorado Department of Revenue on behalf of the U.S. Department of the Interior. In the letter, the Department of Revenue states that Kinder Morgan CO_2 has over-reported transportation allowances and underpaid royalties (due to the use of the Cortez Pipeline tariff as the transportation allowance for purposes of federal royalties) in the amount of $8.5 million for the period from April 2000 through December 2004. The MMS issued a second "Order to Report and Pay" based on the "Audit Issue Letter" in August 2007, and Kinder Morgan CO_2 filed its notice of appeal and statement of reasons in response in September 2007.

The MMS and Kinder Morgan CO_2 have reached a settlement of the March 2007 and August 2007 Orders to Report and Pay. The settlement is subject to final MMS approval and upon approval will be funded from existing reserves and indemnity payments from 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 ("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 did not breach the settlement agreement and did not breach the claimed duty to market carbon dioxide. The jury also found that Kinder Morgan 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 granting a new trial in the case. Kinder Morgan filed a petition with the New Mexico Supreme Court, asking that court to authorize an immediate appeal of the new trial orders. In a 2 to 1 decision, the New Mexico Supreme Court denied Kinder Morgan's petition for immediate review of the new trial orders. The district court has scheduled a new trial to occur beginning on October 19, 2009.

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 Colorado county taxing authorities.

Commercial Litigation Matters

Union Pacific Railroad Company Easements

SFPP, L.P. 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 in 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 has appealed this decision, and in December 2008, the appellate court affirmed the decision. In addition, UPRR contends that it has complete discretion to cause the pipeline to be relocated at SFPP's expense at any time and for any reason, and 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 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 has 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 filed a Petition for Rehearing En Banc and for Panel Rehearing on April 14, 2009.

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.

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 May 2006, the court granted defendants' motions to dismiss as to the counts purporting to assert claims for fraud, but denied defendants' motions to dismiss as to the remaining counts, as well as defendants' motions to strike portions of the complaint. Defendant Kennametal, Inc. has filed a third-party complaint naming the United States and the United States Navy, collectively referred to in this report as the United States, as additional defendants.

In response, the United States removed the case to the United States District Court for the District of Nevada and filed a motion to dismiss the third-party complaint. Plaintiff has also filed a motion to dismiss the United States and/or to remand the case back to state court. By order dated September 25, 2007, the United States District Court granted the motion to dismiss the United States from the case and remanded the Jernee and Sands cases back to the

Second Judicial District Court, State of Nevada, County of Washoe. The cases will now proceed in the State Court. Based on the information available to date, our own preliminary investigation, and the positive results of investigations conducted by State and Federal agencies, we believe that the remaining claims against us in these matters are without merit and intend to defend against them vigorously.

Pipeline Integrity and Releases

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

Pasadena Terminal Fire

On September 23, 2008, a fire occurred in the pit 3 manifold area of our Pasadena, Texas terminal facility. One of our employees was injured and subsequently died. In addition, the pit 3 manifold was severely damaged. The cause of the incident is currently under investigation by the Railroad Commission of Texas and the United States Occupational Safety and Health Administration. The remainder of the facility returned to normal operations within 24 hours of the incident.

Walnut Creek, California Pipeline Rupture

On November 9, 2004, excavation equipment operated by Mountain Cascade, Inc., a third-party contractor on a water main installation project hired by East Bay Municipal Utility District, struck and ruptured an underground petroleum pipeline owned and operated by SFPP, L.P. in Walnut Creek, California. An explosion occurred immediately following the rupture that resulted in five fatalities and several injuries to employees or contractors of Mountain Cascade. Following court ordered mediation, we have settled with plaintiffs in all of the wrongful death cases and the personal injury and property damages cases. On January 12, 2009, the Contra Costa Superior Court granted summary judgment in favor of Kinder Morgan G.P. Services Co., Inc. in the last remaining civil suit – a claim for indemnity brought by co-defendant Camp, Dresser & McKee, Inc. The only remaining pending matter is our appeal of a civil fine of approximately $0.1 million issued by the California Division of Occupational Safety and Health.

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, referred to as Rockies Express), struck an existing subsurface natural gas pipeline owned by Wyoming Interstate Company, a subsidiary of El Paso Pipeline Group. The pipeline was ruptured, resulting in an explosion and fire. The incident occurred in a rural area approximately nine miles southwest of Cheyenne, Wyoming. The incident resulted in one fatality (the operator of the bulldozer) and there were no other reported injuries. The cause of the incident was investigated by the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, referred to in this report as the PHMSA. In March 2008, the PHMSA issued a Notice of Probable Violation, Proposed Civil Penalty and Proposed Compliance Order, referred to in this report 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, 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, 189 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, 189 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 report 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.

Although Plantation does not believe that penalties are warranted, it engaged in settlement discussions with the EPA regarding a potential civil penalty for the November 2006 release as part of broader settlement negotiations with the EPA regarding this spill and three other historical releases from Plantation, including a February 2003 release near Hull, Georgia. Plantation entered into a consent decree with the Department of Justice and the EPA for all four releases and paid approximately $0.7 million, plus performed some additional work to prevent future releases. The payments and work required under the consent decree have been completed and Plantation has asked EPA's concurrence to terminate the consent decree.

In addition, 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 an historical turbine fuel release. The groundwater contamination is underneath at least two lots on which there is current construction of single family homes as 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 residential subdivision. 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 perform other work to ensure protection of the Navy's existing treatment system and water supply.

Oil Spill Near 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 BC Ministry of Environment, the National Energy Board, and the National Transportation Safety Board. Cleanup and environmental remediation is near completion. The 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, the operator of the line, were the primary causes of the accident. No directives, penalties or actions of Kinder Morgan Canada are required as a result of the report. The incident remains under investigation by Provincial agencies. We do not expect this matter to have a material adverse impact on our results of operations or cash flows.

On December 20, 2007 we initiated a lawsuit entitled Trans Mountain Pipeline LP, Trans Mountain Pipeline Inc. and Kinder Morgan Canada Inc. v. The City of Burnaby, et al., Supreme Court of British Columbia, Vancouver Registry No. S078716. The suit alleges that the City of Burnaby and its agents are liable in damages including, but not limited to, all costs and expenses incurred by us as a result of the rupture of the pipeline and subsequent release of crude oil. Defendants have denied liability and discovery has begun.

PHMSA Final Order

On March 27, 2009, the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) issued a Final Order denying Plantation's administrative appeal of a Notice of Probable Violation and proposed Civil Penalty (Notice) in the amount of $0.15 million. The Final Order, which stems from a July 2004 inspection at two Plantation facilities in Virginia, alleges three violations of the PHMSA regulations including that Plantation failed to follow procedures and update certain documents. While Plantation believes it has defenses to the Final Order, it determined that it was not cost effective to appeal the Order and therefore paid the penalty on April 14, 2009. No other work is required by the Final Order and Plantation previously took steps to address the alleged violations. The matter is, therefore, fully resolved.

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 March 31, 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 $227.2 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

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, (PAT) 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 may consolidate the two cases. The parties are now conducting discovery.

State of Texas v. Kinder Morgan Petcoke, L.P.

Harris County, Texas Criminal Court No. 11, Cause No. 1571148. On February 24, 2009, our subsidiary Kinder Morgan Petcoke, L.P. was served with a misdemeanor summons alleging the unintentional discharge of petroleum coke into the Houston Ship Channel during maintenance activities. The maximum potential fine for the alleged violation is $0.2 million. The allegations in the summons are currently under investigation.

Other Environmental

We are subject to environmental cleanup and enforcement actions from time to time. In particular, the federal Comprehensive Environmental Response, Compensation and Liability Act generally imposes joint and several liability for cleanup and enforcement costs on current or 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 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 violations will have a material adverse affect 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 March 31, 2009, we have accrued an environmental reserve of $75.4 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, we have recorded a receivable of $20.3 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.

4. Asset Retirement Obligations

We record liabilities for obligations related to the retirement and removal of long-lived assets used in our businesses. We record the fair value of asset retirement obligations as liabilities on a discounted basis when they are incurred, which is typically at the time the assets are installed or acquired. Amounts recorded for the related assets are increased by the amount of these obligations. Over time, the liabilities increase due to the change in their present value, and the initial capitalized costs will be depreciated over the useful lives of the related assets. The liabilities are eventually extinguished when the asset is taken out of service.

In our CO_2 business segment, we are required to plug and abandon oil and gas wells that have been removed from service and to remove our surface wellhead equipment and compressors. As of March 31, 2009 and December 31, 2008, we have recognized asset retirement obligations in the aggregate amount of $83.0 million and $74.1 million, respectively, relating to these requirements at existing sites within our CO_2 business segment.

In our Natural Gas Pipelines business segment, if we were to cease providing utility services in total or in any particular area, we may be required to remove certain surface facilities and equipment from land belonging to our customers and others (we would generally have no obligations for removal or remediation with respect to equipment and facilities, such as compressor stations, located on land we own). Currently, we have no plans to abandon any of these facilities, however, we believe we can reasonably estimate both the time and costs associated with the retirement of these facilities and as of both March 31, 2009 and December 31, 2008, we have recognized asset retirement obligations in the aggregate amount of $2.4 million relating to the businesses within our Natural Gas Pipelines business segment.

We have included $2.5 million of our total asset retirement obligations as of March 31, 2009 with "Accrued other current liabilities" in our accompanying consolidated balance sheet. The remaining $82.9 million obligation is reported separately as a non-current liability. A reconciliation of the beginning and ending aggregate carrying amount of our asset retirement obligations for each of the three months ended March 31, 2008 and 2007 is as follows (in millions):

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
Balance at beginning of period	$ 76.5	$ 52.2
Liabilities incurred / revised	9.6	0.9
Liabilities settled	(1.8)	(0.9)
Accretion expense	1.1	0.6
Balance at end of period	$ 85.4	$ 52.8

We have various other obligations throughout our businesses to remove facilities and equipment on rights-of-way and other leased facilities. We currently cannot reasonably estimate the fair value of these obligations because the associated assets have indeterminate lives. These assets include pipelines, certain processing plants and distribution facilities, and certain bulk and liquids terminal facilities. An asset retirement obligation, if any, will be recognized once sufficient information is available to reasonably estimate the fair value of the obligation.

5. Distributions

On February 13, 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 December 31, 2008. KMR, our sole i-unitholder, received 1,917,189 additional i-units based on the $1.05 cash distribution per common unit. The distributions were declared on January 21, 2009, payable to unitholders of record as of January 31, 2009.

On April 15, 2009, we declared a cash distribution of $1.05 per unit for the quarterly period ended March 31, 2009. The distribution will be paid on May 15, 2009, to unitholders of record as of April 30, 2009. Our common unitholders and Class B unitholders will receive cash. KMR will receive a distribution of 2,025,208 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 (0.025342) will be issued. This fraction was determined by dividing:

- $1.05, the cash amount distributed per common unit

by

- $41.434, the average of KMR's shares' closing market prices from April 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.

6. Intangibles

Goodwill

For our investments in affiliated entities that are included in our consolidation, the excess cost over underlying fair value of net assets is referred to as goodwill and reported separately as "Goodwill" in our accompanying consolidated balance sheets. Goodwill is not subject to amortization but must be tested for impairment at least annually. Our goodwill impairment measurement date is May 31 of each year. Changes in the carrying amount of our goodwill for the three months ended March 31, 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 adjs.	—	—	—	0.1	—	0.1
Disposals	—	—	—	—	—	—
Impairments	—	—	—	—	—	—
Currency translation adjustments	—	—	—	—	(7.0)	(7.0)
Balance as of March 31, 2009	$ 263.2	$ 288.4	$ 46.1	$ 257.7	$ 196.6	$ 1,052.0

In addition, according to the provisions of Accounting Principles Board Opinion No. 18, "The Equity Method of Accounting for Investments in Common Stock," 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 not subject to amortization but rather to periodic impairment testing. As of both March 31, 2009 and December 31, 2008, we have reported $138.2 million in equity method goodwill within the caption "Investments" in our accompanying consolidated balance sheets.

Other Intangibles

Excluding goodwill, our other intangible assets include customer relationships, contracts and agreements, technology-based assets, and lease value. These intangible assets have definite lives, 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):

	March 31, 2009	December 31, 2008
Customer relationships, contracts and agreements		
Gross carrying amount	$ 246.0	$ 246.0
Accumulated amortization	(54.5)	(51.1)
Net carrying amount	191.5	194.9
Technology-based assets, lease value and other		
Gross carrying amount	13.3	13.3
Accumulated amortization	(2.5)	(2.4)
Net carrying amount	10.8	10.9
Total Other intangibles, net	$ 202.3	$ 205.8

Our customer relationships, contracts and agreements relate primarily to our Terminals business segment, and include relationships and contracts for handling and storage of petroleum, chemical, and dry-bulk materials. The values of these intangible assets were determined by us (often in conjunction with third party valuation specialists) by first, estimating the revenues derived from a customer relationship or contract (offset by the cost and expenses of supporting assets to fulfill the contract), and secondly, discounting the revenues at a risk adjusted discount rate.

For each of the first three months of 2009 and 2008, the amortization expense on our intangibles totaled $3.5 million, and these expense amounts primarily consisted of amortization of our customer relationships, contracts and agreements. As of March 31, 2009, the weighted average amortization period for our intangible assets was approximately 17.1 years. Our estimated amortization expense for these assets for each of the next five fiscal years (2010 – 2014) is approximately $13.6 million, $13.4 million, $13.1 million, $13.1 million and $13.1 million, respectively.

7. Debt

Our outstanding short-term debt as of March 31, 2009 was $484.9 million. We classify our debt based on the contractual maturity dates of the underlying debt instruments or as of the earliest put date available to our debt holders. We defer costs associated with debt issuance over the applicable term.

Our outstanding short-term debt balance consisted of (i) $439.8 million in outstanding borrowings under our unsecured revolving bank credit facility as of March 31, 2009 (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 $9.4 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 $6.7 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).

The weighted average interest rate on all of our borrowings (both short and long term) was approximately 5.11% during the first quarter of 2009 and approximately 5.77% during the first quarter of 2008.

Credit Facility

Our $1.85 billion five-year 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. 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 credit facility matures August 18, 2010 and can be amended to allow for borrowings up to $2.0 billion. Borrowings under our credit facility can be used for partnership purposes and as a backup for our commercial paper program. The outstanding balance under our five-year credit facility was $439.8 million as of March 31, 2009. As of December 31, 2008, there were no borrowings under the credit facility.

As of March 31, 2009, the amount available for borrowing under our credit facility was reduced by an aggregate amount of $290.0 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 $55.9 million in letters of credit that support our pipeline and terminal operations in Canada; (iv) a $26.8 million letter of credit that supports our indemnification obligations on the Series D note borrowings of Cortez Capital Corporation; and (v) a combined $16.5 million in other letters of credit supporting other obligations of us and our subsidiaries.

In addition, on September 15, 2008, Lehman Brothers Holdings Inc. filed for bankruptcy protection under the provisions of Chapter 11 of the U.S. Bankruptcy Code. One Lehman entity was a lending institution that provided $63.3 million of our credit facility. During the first quarter of 2009, we amended our facility to remove Lehman as a lender, thus reducing the facility by $63.3 million. The commitments of the other banks remain unchanged, and the facility is not defaulted.

Commercial Paper Program

On October 13, 2008, Standard & Poor's Rating Services lowered our short-term credit rating to A-3 from A-2. As a result of this revision and current commercial paper market conditions, we are currently unable to access commercial paper borrowings, and as of both March 31, 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.

Kinder Morgan Operating L.P. "A" Debt

As part of the purchase price consideration for our January 1, 2007 acquisition of the remaining approximately 50.2% interest in the Cochin pipeline system that we did not already own, 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%. The principal amount of the note, along with interest, is due in five annual installments of $10.0 million beginning March 31, 2008. As of December 31, 2008, the measured present value of the note was $36.6 million. We paid the second installment on March 31, 2009, and the final payment is due March 31, 2012. Our subsidiaries Kinder Morgan Operating L.P. "A" and Kinder Morgan Canada Company are the obligors on the note, and as of March 31, 2009, the measured present value of the note was $26.9 million.

Interest Rate Swaps

Information on our interest rate swaps is contained in Note 10.

Contingent Debt

As prescribed by the provisions of Financial Accounting Standards Board Interpretation (FIN) No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others," we disclose certain types of guarantees or indemnifications we have made. These disclosures cover certain types of guarantees included within debt agreements, even if the likelihood of requiring our performance under such guarantee is remote. The following is a description of our contingent debt agreements as of March 31, 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 March 31, 2009, the debt facilities of Cortez Capital Corporation consisted of (i) $53.6 million of Series D notes due May 15, 2013; (ii) a $125 million short-term commercial paper program; and (iii) a $125 million five-year committed revolving credit facility due December 22, 2009 (to support the above-mentioned $125 million commercial paper program). In October 2008, Standard & Poor's Rating Services lowered Cortez Capital Corporation's short-term credit rating to A-3 from A-2. As a result of this revision and current commercial paper market conditions, Cortez is unable to access commercial paper borrowings; however, it expects that its financing and liquidity needs will continue to be met through borrowings made under its long-term bank credit facility.

As of March 31, 2009, in addition to the $53.6 million of outstanding Series D notes, Cortez Capital Corporation had outstanding borrowings of $109.5 million under its five-year credit facility. Accordingly, as of March 31, 2009, our contingent share of Cortez's debt was $81.6 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 $53.6 million principal amount of the notes is due in five equal annual installments of approximately $10.7 million beginning May 2009. 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 March 31, 2009, JP Morgan Chase has issued a letter of credit on our behalf in the amount of $26.8 million to secure our indemnification obligations to Shell for 50% of the $53.6 million in principal amount of Series D notes outstanding as of that date.

Nassau County, Florida Ocean Highway and Port Authority Debt

We have posted a letter of credit as security for borrowings under Adjustable Demand Revenue Bonds issued by the Nassau County, Florida Ocean Highway and Port Authority. The bonds were issued for the purpose of constructing certain port improvements located in Fernandino Beach, Nassau County, Florida. Our subsidiary, Nassau Terminals LLC is the operator of the marine port facilities. The bond indenture is for 30 years and allows the bonds to remain outstanding until December 1, 2020. Principal payments on the bonds are made on the first of December each year and corresponding reductions are made to the letter of credit. As of March 31, 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' (i) $2.0 billion five-year, unsecured revolving credit facility due April 28, 2011; (ii) $2.0 billion commercial paper program; and (iii) $600 million in principal amount of floating rate senior notes due August 20, 2009. 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 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. In October 2008, Standard & Poor's Rating Services lowered Rockies Express Pipeline LLC's 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 March 31, 2009, in addition to the $600 million in floating rate senior notes, Rockies Express had outstanding borrowings of $1,913.0 million under its five-year credit facility. Accordingly, as of March 31, 2009, our contingent share of Rockies Express' debt was $1,281.6 million (51% of total guaranteed borrowings). One of the Lehman entities was a lending bank with a $41 million commitment to Rockies Express Pipeline LLC's $2.0 billion credit facility. During the first quarter of 2009, Rockies Express amended its facility to remove Lehman as a lender, thus reducing the facility by $41.0 million. However, the commitments of the other banks remain unchanged, and the facility is not defaulted.

The $600 million in principal amount of senior notes were issued on September 20, 2007. The notes are unsecured and are not redeemable prior to maturity. Interest on the notes is paid and computed quarterly at an interest rate of three-month LIBOR (with a floor of 4.25%) plus a spread of 0.85%. Upon maturity in August 2009, we expect that Rockies Express will repay these senior notes from equity contributions received from its member owners. As of March 31, 2009, Rockies Express entered into a floating-to-fixed interest rate swap agreement having a notional principal amount of $300 million and a maturity date of August 20, 2009. The interest rate swap agreement effectively converts the interest expense associated with $300 million of these senior notes from its stated variable rate to a fixed rate of 5.47%.

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 Pipeline LLC, borrowings under Midcontinent's $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 will be used to finance the construction of the Midcontinent Express Pipeline system and to pay related expenses**.** One of the Lehman entities was a lending bank with a $100 million commitment to the Midcontinent Express $1.4 billion credit facility. Since declaring bankruptcy, Lehman has not met its obligations to lend under the credit facility. The commitments of the other banks remain unchanged and the facility is not defaulted.

Midcontinent Express Pipeline LLC 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%. As of March 31, 2009, Midcontinent Express Pipeline LLC had $1,218.1 million borrowed under its three-year credit facility. Accordingly, as of March 31, 2009, our contingent share of Midcontinent Express' debt was $609.1 million (50% of total borrowings).

Furthermore, the revolving credit facility can be used for the issuance of letters of credit to support the construction of the Midcontinent Express Pipeline, and as of March 31, 2009, a letter of credit having a face amount of $33.3 million was issued under the credit facility. Accordingly, as of March 31, 2009, our contingent responsibility with regard to this outstanding letter of credit was $16.7 million (50% of total face amount).

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.

8. Partners' Capital

Limited Partner Units

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

	March 31, 2009	December 31, 2008
Common units	189,250,710	182,969,427
Class B units	5,313,400	5,313,400
i-units	79,915,095	77,997,906
Total limited partner units	274,479,205	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 March 31, 2009, our total common units consisted of 172,880,282 units held by third parties, 14,646,428 units held by Knight 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 Knight and its consolidated affiliates (excluding our general partner) and 1,724,000 units held by our general partner.

On both March 31, 2009 and December 31, 2008, all of our 5,313,400 Class B units were held by a wholly-owned subsidiary of Knight. 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 Knight in December 2000.

On both March 31, 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 unit. Based on the preceding, KMR received a distribution of 1,917,189 i-units from us on February 13, 2009, based on the $1.05 per unit distributed to our common unitholders on that date.

Equity Issuances

On January 16, 2009, we entered into an Equity Distribution Agreement with UBS Securities LLC. 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 first quarter of 2009, we issued 612,083 of our common units pursuant to this Agreement. After commissions of $0.6 million, we received net proceeds of approximately $29.9 million for the issuance of these common units, and we used the proceeds to reduce the borrowings under our bank credit facility.

In addition, on March 3, 2009, we issued, in an underwritten public offering, 5,500,000 of our common units at a price of $46.95 per unit, less commissions and underwriting expenses. At the time of the offering, we granted the underwriters a 30-day option to purchase up to an additional 825,000 common units from us on the same terms and conditions, and pursuant to a partial exercise of this option, we issued an additional 166,000 common units on March 27, 2009. After commissions and underwriting expenses, we received net proceeds of $258.0 million for the issuance of these 5,666,000 common units, and we used the proceeds 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.

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 February 13, 2009 for the fourth quarter of 2008 required an incentive distribution to our general partner of $216.6 million. Our distribution of $0.92 per unit paid on February 14, 2008 for the fourth quarter of 2007 resulted in an incentive distribution payment to our general partner in the amount of $170.3 million. The increased incentive distribution to our general partner paid for the fourth quarter of 2008 over the incentive distribution paid for the fourth quarter of 2007 reflects the increase in the amount distributed per unit as well as the issuance of additional units.

Our declared distribution for the first quarter of 2009 of $1.05 per unit will result in an incentive distribution to our general partner of $223.2 million. This compares to our distribution of $0.96 per unit and incentive distribution to our general partner of $185.8 million for the first quarter of 2008.

9. Comprehensive Income

Comprehensive income is the change in our Partners' Capital that results from periodic revenues, expenses, gains and losses, as well as any other recognized changes that occur for reasons other than investments by and distributions to our partners. The difference between our comprehensive income and our net income represents our other comprehensive income.

For each of the three month periods ended March 31, 2009 and 2008, the components of our other comprehensive income/(loss) included (i) unrealized gains or losses on energy commodity derivative contracts utilized for hedging purposes; (ii) foreign currency translation adjustments; and (iii) unrealized gains or losses related to changes in pension and other post-retirement benefit plan liabilities. Our total comprehensive income was as follows (in millions):

	Three Months Ended March 31,	
	2009	2008
Net Income	$ 266.8	$ 350.7
Other comprehensive loss:		
Change in fair value of derivative contracts utilized for hedging purposes	35.9	(406.9)
Reclassification of change in fair value of derivative contracts to net income	(17.3)	162.4
Foreign currency translation adjustments	(54.8)	(55.1)
Adjustments to pension and other post-retirement benefit plan actuarial gains/losses; and reclassifications of pension and other post-retirement benefit plan actuarial gains/losses, transition obligations and prior service costs/credits to net income, net of tax	(2.8)	3.5
Total other comprehensive loss	(39.0)	(296.1)
Comprehensive income	$ 227.8	$ 54.6
Comprehensive income attributable to the noncontrolling interest	(2.5)	(1.0)
Comprehensive income attributable to Kinder Morgan Energy Partners, L.P. & Subs	$ 225.3	$ 53.6

10. 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, and we account for these hedging transactions according to the provisions of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" and associated amendments, collectively, SFAS No. 133.

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.

Our principal use of energy commodity derivative contracts is to mitigate the risk associated with unfavorable market movements in the price of energy commodities. The unfavorable price changes are often caused by shifts in the supply and demand for these commodities, as well as their locations. 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 SFAS No. 133, the portion of the gain or loss on the derivative instrument 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 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. We currently do not exclude any component of the derivative contracts' gain or loss from the assessment of hedge effectiveness.

During the three months ended March 31, 2009 and 2008, we reclassified a gain of $17.3 million and a loss of $162.4 million, respectively, from "Accumulated other comprehensive loss" into earnings. All amounts reclassified into net income during the first three months of both years resulted from the hedged forecasted transactions actually affecting earnings (for example, 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.

Our consolidated "Accumulated other comprehensive loss" balance was $326.3 million as of March 31, 2009, and $287.7 million as of December 31, 2008. These consolidated totals included "Accumulated other comprehensive loss" amounts associated with energy commodity price risk management activities of $45.4 million as of March 31, 2009 and $63.2 million as of December 31, 2008. Approximately $27.2 million of the total amount associated with our energy commodity price risk management activities as of March 31, 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).

As of March 31, 2009, we had the following outstanding commodity forward contracts that were entered into to hedge forecasted energy commodity purchases and sales:

Derivatives designated as hedging contracts under SFAS No. 133	Notional Quantity
Crude oil	30.6 million barrels
Natural gas(a)............................	19.7 billion cubic feet

(a) Notional quantities are shown net of short positions.

As of March 31, 2009, we had the following outstanding commodity forward contracts that were not designated as hedges for accounting purposes:

Derivatives not designated as hedging contracts under SFAS No. 133	Notional Quantity
Crude oil	0.1 million barrels
Natural gas(a)............................	0.5 billion cubic feet

(a) Notional quantities are shown net.

As of March 31, 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 April 2013.

For derivative instruments 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 SFAS No. 133. Consequently, we discontinued hedge accounting treatment for these relationships (primarily crude oil hedges of heavy natural gas liquids sales) effective as of March 31, 2008. Since the forecasted sales of natural gas liquids volumes (the hedged item) are 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 will not be reclassified into earnings until the physical transactions occurs. 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.

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 instruments 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 quarter 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 five additional fixed-to-variable swap agreements having a combined notional principal amount of $1 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 7).

Therefore, as of March 31, 2009, we had a combined notional principal amount of $3.25 billion of fixed-to-variable interest rate swap agreements effectively converting the interest expense associated with certain series of our senior notes from fixed rates to variable rates based on an interest rate of LIBOR plus a spread. All of our swap agreements have termination dates that correspond to the maturity dates of the related series of senior notes and, as of March 31, 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.

Subsequent Event

In April 2009, we entered into additional fixed-to-variable interest rate swap agreements having a combined notional principal amount of $750 million. The agreements consisted of notional principal amounts of (i) $100 million and a maturity date of September 15, 2012; (ii) $225 million and a maturity date of December 15, 2013; (iii) $300 million and a maturity date of March 15, 2031; and (iv) $125 million and a maturity date of March 15, 2032.

Fair Value of Derivative Contracts

The following table summarizes the fair values of our derivative contracts included on our accompanying consolidated balance sheets as of March 31, 2009 and December 31, 2008 (in millions):

Fair Value of Derivative Contracts

	Asset Derivatives				Liability Derivatives			
	March 31, 2009		December 31, 2008		March 31, 2009		December 31, 2008	
	Balance sheet Location	**Fair value**	**Balance sheet Location**	**Fair value**	**Balance sheet Location**	**Fair value**	**Balance sheet location**	**Fair Value**
Derivatives designated as hedging contracts under SFAS No. 133								
Energy commodity derivative contracts	Other current Assets	$115.7	Other current Assets	$113.5	Accrued other current liabilities	$(138.6)	Accrued other current liabilities	$(129.4)
	Deferred charges and other assets	76.0	Deferred charges and other assets	48.9	Other long-term liabilities and deferred credits	(94.6)	Other long-term liabilities and deferred credits	(92.2)
Subtotal		191.7		162.4		(233.2)		(221.6)
Interest rate Swap agreements	Deferred charges and other assets	475.7	Deferred charges and other assets	747.1	Other long-term liabilities and deferred credits	(3.4)	Other long-term liabilities and deferred credits	—
Total		667.4		909.5		(236.6)		(221.6)
Derivatives not designated as hedging contracts under SFAS No. 133								
Energy commodity derivative contracts	Other current Assets	2.8	Other current Assets	1.8	Accrued other current liabilities	(0.8)	Accrued other current liabilities	(0.1)
Total derivatives		$670.2		$911.3		$(237.4)		$(221.7)

The offsetting entry to adjust the carrying value of the debt securities whose fair value was being hedged is included within “Value of interest rate swaps” on our accompanying consolidated balance sheets, which also includes any unamortized portion of proceeds received from the early termination of interest rate swap agreements. As of March 31, 2009 and December 31, 2008, this unamortized premium totaled $342.3 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 months ended March 31, 2009 and March 31, 2008 (in millions):

Derivatives in SFAS No. 133 fair value hedging relationships	**Location of gain/(loss) recognized in income on derivative**	**Amount of gain/(loss) recognized in income on derivative**		**Hedged items in SFAS No. 133 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**	
		First Quarter 2009	**First Quarter 2008**			**First Quarter 2009**	**First Quarter 2008**
Interest rate swap agreements	Interest, net – income/(expense)	$(130.4)	$119.1	Fixed rate debt	Interest, net – income/(expense)	$130.4	$(119.1)
Total		$(130.4)	$119.1	**Total**		$130.4	$(119.1)

The table above reflects 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. It does not reflect the impact on interest expense of the interest rate swaps under which we pay variable and receive fixed.

Derivatives in SFAS No. 133 cash flow hedging relationships	Amount of gain/(loss) recognized in OCI on derivative (effective portion) First Quarter 2009	2008	Location of gain/(loss) reclassified from Accumulated OCI into income (effective portion)	Amount of gain/(loss) reclassified from Accumulated OCI into income (effective portion) First Quarter 2009	2008	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) First Quarter 2009	2008
Energy commodity derivative contracts	$35.9	$(406.9)	Revenues-Natural Gas sales	$1.7	$—	Revenues	—	—
			Revenues-Product sales and other	16.0	(153.6)			
			Gas purchases and other costs of sales	(0.4)	(8.8)	Gas purchases and other costs of sales	—	$(2.4)
Total	$35.9	$(406.9)	**Total**	$17.3	$(162.4)	**Total**	—	$(2.4)

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Derivatives not designated as hedging contracts under SFAS No. 133	Location of gain/(loss) recognized in income on derivative	Amount of gain/(loss) recognized in income on derivative First Quarter 2009	First Quarter 2008
Energy commodity derivative contracts	Gas purchases and other costs of sales	$(0.4)	—
Total		$(0.4)	—

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 March 31, 2009 was (in millions):

	Asset Position
Interest rate swap agreements	$ 475.7
Energy commodity derivative contracts	194.5
Gross exposure	670.2
Netting agreement impact	(127.5)
Net exposure	$ 542.7

In conjunction with the purchase of exchange-traded derivative contracts or when the market value of our derivative contracts with specific counterparties exceeds established limits, we are required to provide collateral to our counterparties, which may include posting letters of credit or placing cash in margin accounts. As of March 31, 2009 and December 31, 2008, we had outstanding letters of credit totaling less than $0.1 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 March 31, 2009, we had cash margin deposits associated with our energy commodity contract positions and over-the-counter swap partners totaling $3.3 million, and we reported this amount as "Restricted deposits" in our accompanying 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 March 31, 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	$ 75.9	$ 79.2
Two notches to below BBB-/Baa3 (below investment grade)	$ 57.8	$ 137.0

(a) If there are split ratings among the independent credit rating agencies, most counterparties use the higher credit rating to determine our incremental collateral obligations, while the remaining use the lower credit rating. Therefore, a one notch downgrade to BBB-/Baa3 by one agency would not trigger the entire $75.9 million incremental obligation.

(b) Includes current posting at current rating.

11. Fair Value

Fair value measurements and disclosures are made in accordance with the provisions of SFAS No. 157, "Fair Value Measurements". While not requiring material new fair value measurements, SFAS No. 157 established a single definition of fair value in generally accepted accounting principles and expanded disclosures about fair value measurements. The provisions of this Statement apply to other accounting pronouncements that require or permit fair value measurements; the Financial Accounting Standards Board having previously concluded in those accounting pronouncements that fair value is the relevant measurement attribute.

On February 12, 2008, the FASB issued FASB Staff Position No. FAS 157-2, "Effective Date of FASB Statement No. 157," referred to as FAS 157-2 in this report. FAS 157-2 delayed the effective date of SFAS No. 157 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually).

Accordingly, we adopted SFAS No. 157 for financial assets and financial liabilities effective January 1, 2008. 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. We adopted SFAS No. 157 for non-financial assets and non-financial liabilities effective January 1, 2009. This includes applying the provisions of SFAS No. 157 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 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. For more information on subsequent Staff Positions issued by the FASB pertaining to SFAS No. 157, see Note 16.

SFAS No. 157 established a hierarchal disclosure framework associated with the level of pricing observability utilized in measuring fair value. This framework defined three levels of inputs to the fair value measurement process, and requires that each fair value measurement 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 SFAS No. 157 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).

The following tables summarize the fair value measurements of our (i) energy commodity derivative contracts; and (ii) interest rate swap agreements as of both March 31, 2009 and December 31, 2008, based on the three levels established by SFAS No. 157, 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 March 31, 2009				
Energy commodity derivative contracts(a)	$ 194.5	$ 0.1	$ 126.5	$ 67.9
Interest rate swap agreements	475.7	—	475.7	—
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 March 31, 2009				
Energy commodity derivative contracts(c)	$ (234.0)	$ —	$ (219.5)	$ (14.5)
Interest rate swap agreements	(3.4)	—	(3.4)	—
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 NYMEX natural gas futures. Level 3 consists primarily of West Texas Sour hedges, 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. 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 each of the three months ended March 31, 2009 and 2008 (in millions):

Significant Unobservable Inputs (Level 3)

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
Derivatives-net asset/(liability)		
Beginning of Period	$ 44.1	$ (100.3)
Realized and unrealized net losses	6.3	(44.8)
Purchases and settlements	3.0	21.3
Transfers in (out) of Level 3	—	—
End of Period	$ 53.4	$ (123.8)
Change in unrealized net losses relating to contracts still held at end of period	$ (14.5)	$ (37.7)

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.

12. Reportable Segments

We divide our operations into five reportable business segments:

- Products Pipelines;
- Natural Gas Pipelines;
- CO_2;
- Terminals; and
- Kinder Morgan Canada

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 minority interest (also referred to as net income attributable to the noncontrolling interest). 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.

Our Products Pipelines segment derives its revenues primarily from the transportation and terminaling of refined petroleum products, including gasoline, diesel fuel, jet fuel and natural gas liquids. Our Natural Gas Pipelines segment derives its revenues primarily from the sale, transport, processing, treating, storage and gathering of natural gas. Our CO_2 segment derives its revenues primarily from the production and sale of crude oil from fields in the Permian Basin of West Texas and from the transportation and marketing of carbon dioxide used as a flooding medium for recovering crude oil from mature oil fields. Our Terminals segment derives its revenues primarily from 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. Our Kinder Morgan Canada business segment derives its revenues primarily from the transportation of crude oil and refined products.

As discussed in Note 2, due to the October 2007 sale of our North System, an approximately 1,600-mile interstate common carrier pipeline system whose operating results were included as part of our Products Pipelines business segment, we accounted for the North System business as a discontinued operation. Consistent with the management approach of identifying and reporting discrete financial information on operating segments, we have included the additional $0.5 million gain on disposal of the North System recognized in the first quarter of 2008 within our Products Pipelines business segment disclosures presented in this report for the first quarter of 2008 and, except for this gain, we recorded no other financial results from the operations of the North System during the first quarter of 2008.

Selected financial information by segment follows (in millions):

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
Revenues		
Products Pipelines		
Revenues from external customers	$ 188.2	$ 198.3
Intersegment revenues	—	—
Natural Gas Pipelines		
Revenues from external customers	1,051.7	1,912.5
Intersegment revenues	—	—
CO_2		
Revenues from external customers	228.9	286.4
Intersegment revenues	—	—
Terminals		
Revenues from external customers	267.6	280.0
Intersegment revenues	0.2	0.2
Kinder Morgan Canada		
Revenues from external customers	50.1	43.1
Intersegment revenues	—	—
Total segment revenues	1,786.7	2,720.5
Less: Total intersegment revenues	(0.2)	(0.2)
Total consolidated revenues	$ 1,786.5	$ 2,720.3
Segment earnings before depreciation, depletion, amortization and amortization of excess cost of equity investments(a)		
Products Pipelines	$ 145.4	$ 140.7
Natural Gas Pipelines	200.8	188.2
CO_2	167.4	199.8
Terminals	134.7	125.8
Kinder Morgan Canada	19.5	30.2
Total segment earnings before DD&A	667.8	684.7
Total segment depreciation, depletion and amortization	(210.2)	(158.1)
Total segment amortization of excess cost of investments	(1.4)	(1.4)
General and administrative expenses	(82.5)	(76.8)
Unallocable interest expense, net of interest income	(104.6)	(97.7)
Unallocable income tax benefit (expense)	(2.3)	—
Total consolidated net income	$ 266.8	$ 350.7

Assets	March 31, 2009	December 31, 2008
Products Pipelines	$ 4,182.0	$ 4,183.0
Natural Gas Pipelines	5,549.7	5,535.9
CO_2	2,350.9	2,339.9
Terminals	3,376.1	3,347.6
Kinder Morgan Canada	1,503.9	1,583.9
Total segment assets	16,962.6	16,990.3
Corporate assets(b)	619.1	895.5
Total consolidated assets	$ 17,581.7	$ 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) 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.

For further information about each segment's business, see Item 2 "Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations" included elsewhere in this report.

13. Pensions and Other Post-Retirement Benefits

Our subsidiaries Kinder Morgan Canada Inc. and Trans Mountain Pipeline Inc. (as general partner of Trans Mountain Pipeline L.P.) are sponsors of pension and other post-retirement benefit plans for eligible employees of our Trans Mountain business. The plans include registered defined benefit pension plans, supplemental unfunded arrangements, which provide pension benefits in excess of statutory limits, and defined contributory plans. We also provide post-retirement benefits other than pensions for retired employees. Our combined net periodic benefit costs for these Trans Mountain pension and post-retirement benefit plans for each of the first three months of 2009 and 2008 were approximately $0.8 million. As of March 31, 2009, we estimate our overall net periodic pension and post-retirement benefit costs for these plans for the year 2009 will be approximately $3.1 million, recognized ratably over the year, although this estimate could change if there is a significant event, such as a plan amendment or a plan curtailment, which would require a remeasurement of liabilities. We expect to contribute approximately $4.8 million to these benefit plans in 2009.

Additionally, in connection with our acquisition of SFPP, L.P. and Kinder Morgan Bulk Terminals, Inc. in 1998, we acquired certain liabilities for pension and post-retirement benefits. We provide medical and life insurance benefits to current employees, their covered dependents and beneficiaries of SFPP and Kinder Morgan Bulk Terminals. We also provide the same benefits to former salaried employees of SFPP. Additionally, we will continue to fund these costs for those employees currently in the plan during their retirement years. SFPP's post-retirement benefit plan is frozen and no additional participants may join the plan.

As of March 31, 2009, we estimate our overall net periodic post-retirement benefit cost for the SFPP post-retirement benefit plan for the year 2009 will be a credit of approximately $0.1 million; however, this estimate could change if a future significant event would require a remeasurement of liabilities. During each of the first quarters of 2009 and 2008, our net periodic benefit cost for the SFPP post-retirement benefit plan was a credit of less than $0.1 million. The credits resulted in increases to income, largely due to amortizations of an actuarial gain and a negative prior service cost. In addition, we expect to contribute approximately $0.3 million to this post-retirement benefit plan in 2009.

The noncontributory defined benefit pension plan covering the former employees of Kinder Morgan Bulk Terminals is the Knight Inc. Retirement Plan. The benefits under this plan are based primarily upon years of service and final average pensionable earnings; however, benefit accruals were frozen as of December 31, 1998.

14. 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 $87.3 million as of March 31, 2009, and $88.5 million as of December 31, 2008. Of these amounts, $2.5 million and $3.7 million were included within "Accounts, notes and interest receivable, net—Related parties," on our accompanying consolidated balance sheets as of March 31, 2009 and December 31, 2008, respectively, and the remainder was included within "Notes receivable—Related parties" 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 Knight on August 28, 2008, we acquired a long-term investment in a 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 Knight'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 March 31, 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

$90.1 million and $93.3 million, respectively, and we included these amounts within "Notes receivable─Related parties" on our accompanying consolidated balance sheets.

Knight Asset Contributions

In conjunction with our acquisition of (i) certain Natural Gas Pipelines assets and partnership interests from Knight in December 1999 and December 2000; and (ii) all of the partnership interest in TransColorado Gas Transmission Company from two wholly-owned subsidiaries of Knight on November 1, 2004, Knight agreed to indemnify us and Kinder Morgan G.P., Inc. with respect to approximately $733.5 million of our debt. Knight would be obligated to perform under this indemnity only if we are unable and/or our assets were insufficient to satisfy our obligations.

Fair Value of Energy Commodity Derivative Contracts

As a result of the May 2007 going-private transaction of Knight, as discussed in Note 1, a number of individuals and entities became significant investors in Knight. By virtue of the size of their ownership interest in Knight, 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 on our accompanying consolidated balance sheets as of March 31, 2009 and December 31, 2008 (in millions):

	March 31, 2009	December 31, 2008
Derivatives - asset/(liability)		
Other current assets	$ 46.5	$ 60.4
Deferred charges and other assets	27.2	20.1
Accrued other current liabilities	(9.8)	(13.2)
Other long-term liabilities and deferred credits	$ (24.4)	$ (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 and is its sole managing member. Knight, 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, Knight 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 Knight 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.

15. 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 three months ended March 31, 2009.

Notice of Proposed Rulemaking – Natural Gas Price Transparency

On November 20, 2008, the FERC issued Order 720, which established new reporting requirements for interstate and major non-interstate natural gas pipelines. A major non-interstate pipeline is defined as a pipeline who delivers annually more than 50 million MMBtu (million British thermal units) of natural gas measured in average deliveries for the previous three calendar years. 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 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 when gas is scheduled at the point. 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 with the requirements of Order No 720 until 150 days following the issuance of an order addressing the pending requests for rehearing. A technical conference is scheduled for May 18, 2009 to discuss two proposed posting requirements for major non-interstate pipelines. We do not expect this Order to have a material impact on our consolidated financial statements.

In Order No. 704, the FERC established reporting requirements on annual volumes of relevant transactions. The FERC issued Order No. 704-A on September 18, 2008. This order generally affirmed the rule, while clarifying what information certain natural gas market participants must report in Form 552. The revisions pertain to the reporting of transactions occurring in calendar year 2008. Order 704-A became effective October 27, 2009. On December 18, 2008, the FERC issued Order No. 704-B, denying rehearing and reconsideration of Order No. 704-A and granting a clarification regarding certain reportable volumes. On April 9, 2009, the FERC granted an extension of time until July 1, 2009 for filing the initial Form 552.

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 is requesting authorization to construct and operate certain facilities that will comprise its Meeker, Colorado to Cheyenne, Wyoming Rockies Express Pipeline expansion project. We operate the Rockies Express Pipeline and we own a 51% interest in Rockies Express Pipeline LLC.

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 April 2010. The total estimated cost for the proposed project is approximately $78 million. Rockies Express submitted a FERC application seeking approval to construct and operate this expansion on February 3, 2009.

Rockies Express Pipeline-East Project

Construction continued during the first 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. Rockies Express-East is currently projected to commence service in May 2009, with capacity of approximately 1.6 billion cubic feet per day of natural gas. Service to the Lebanon Hub in Warren County, Ohio is expected to commence on June 15, 2009, and final completion and deliveries to Clarington, Ohio are expected to commence by November 1, 2009. Including expansions, our current estimate of total construction costs on the entire Rockies Express Pipeline is now approximately $6.6 billion (consistent with our April 15, 2009 first quarter earnings press release).

On October 31, 2008, Rockies Express filed an amendment to its certificate application, seeking authorization to revise its tariff-based recourse rates for transportation service on the Rockies Express East pipeline segment to reflect updated construction costs for the project. By order issued March 16, 2009, the FERC authorized the revised rates as filed by Rockies Express.

Kinder Morgan Interstate Gas Transmission Pipeline - Huntsman 2009 Expansion Project

Our Kinder Morgan Interstate Gas Transmission natural gas pipeline system, 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 requests 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 have executed a firm precedent agreement for 100% of the capacity to be created by the project facilities over a five-year term.

Kinder Morgan Louisiana Pipeline

Construction continued during the first quarter of 2009 on our previously announced Kinder Morgan Louisiana Pipeline. The entire estimated project cost for the approximately 135-mile natural gas pipeline system is now expected to be approximately $980 million (consistent with our April 15, 2009 first quarter earnings press release). All of the capacity of approximately 3.2 billion cubic feet per day of natural gas on the pipeline has been fully subscribed by Chevron and Total, and the pipeline is expected to be fully operational in June 2009. One transportation contract will be effective starting in June 2009, and the second during the third quarter of 2009.

On December 30, 2008, we filed a second amendment to our certificate application, seeking authorization to revise our initial rates for transportation service on the Kinder Morgan Louisiana Pipeline system to reflect additional increases in projected construction costs for the project (a first amendment revising our initial rates was filed in July 2008 and accepted by the FERC in August 2008). The filing was approved by the FERC on February 27, 2009. On April 16, 2009, Kinder Morgan Louisiana Pipeline received authorization from the FERC to begin service on Leg 2 of the pipeline. Service on Leg 2 started on April 18, 2009.

Midcontinent Express Pipeline

Construction continued during the first quarter of 2009 on the previously announced Midcontinent Express Pipeline project. 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 will extend from southeast Oklahoma, across northeast Texas, northern Louisiana and central Mississippi, and terminate at an interconnection with the Transco Pipeline near Butler, Alabama. The entire estimated project cost for the approximately 500-mile natural gas pipeline system is now expected to be approximately $2.3 billion (consistent with our April 15, 2009 first quarter earnings press release). Service to an interconnect with Natural Gas Pipeline Company of America LLC's pipeline in northeast Texas began on April 10, 2009, and the remainder of the first portion of the pipeline (to an interconnection with Columbia Gas Transportation in eastern Louisiana) began interim service on April 24, 2009. Deliveries to Texas Gas Transmission began on April 28, 2009 and deliveries to ANR Pipeline company near Perryville, La., in Ouachita Parish, began on May 1, 2009. Receipts from Enogex Bennington Bryan and deliveries to CenterPoint Energy Gas Transmission near Delhi, Louisiana, in Richland Parish, will be available the first half of May 2009. The second and final construction phase (to the Transco Pipeline interconnect) is expected to be completed by August 1, 2009.

On January 9, 2009, Midcontinent Express filed an amendment to its original certificate application requesting authorization to revise its initial rates for transportation service on the pipeline system to reflect an increase in projected construction costs for the project. The filing was approved by the FERC on March 25, 2009.

Fayetteville Express Pipeline

Development continued during the first 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 ten year binding commitments totaling 1.85 billion cubic feet per day of capacity. 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 April 15, 2009 first quarter earnings press release).

16. Recent Accounting Pronouncements

EITF 04-5

In June 2005, the Emerging Issues Task Force reached a consensus on Issue No. 04-5, or EITF 04-5, “Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights.” EITF 04-5 provides guidance for purposes of assessing whether certain limited partners rights might preclude a general partner from controlling a limited partnership. The adoption of EITF 04-5 did not have an effect on our consolidated financial statements; nonetheless, as a result of EITF 04-5, as of January 1, 2006, our financial statements are consolidated into the consolidated financial statements of Knight. Notwithstanding the consolidation of our financial statements into the consolidated financial statements of Knight pursuant to EITF 04-5, Knight 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 Knight’s financial statements is a legal determination based on the entity that incurs the liability. The determination of responsibility for payment among entities in our consolidated group of subsidiaries was not impacted by the adoption of EITF 04-5.

SFAS 141(R) and FASB Staff Position No. 141(R)-a

On December 4, 2007, the FASB issued SFAS No. 141R (revised 2007), “Business Combinations.” Although this statement amends and replaces SFAS No. 141, it retains the fundamental requirements in SFAS No. 141 that (i) the purchase method of accounting be used for all business combinations; and (ii) an acquirer be identified for each business combination. This Statement 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; however, this Statement does not apply to a combination between entities or businesses under common control.

Significant provisions of SFAS No. 141R 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 Statement was adopted by us effective January 1, 2009, and the adoption of this Statement did not have a material impact on our consolidated financial statements.

On April 1, 2009, the FASB issued FASB Staff Position No. FAS 141(R)-a, “Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies.” This Staff Position amends the provisions related to the initial recognition and measurement, subsequent measurement and disclosure of assets and liabilities arising form contingencies in a business combination under SFAS No. 141R. This Staff Position carries forward the requirements in SFAS No. 141, “Business Combinations” for acquired contingencies, which would require that such contingencies 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 SFAS No. 5, "Accounting for Contingencies." This Staff Position will have the same effective date as SFAS No. 141R, and did not have a material impact on our consolidated financial statements.

SFAS No. 160

On December 4, 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements – an amendment of ARB No. 51." This Statement changes the accounting and reporting for noncontrolling interests, sometimes referred to as minority interests, in consolidated financial statements. A noncontrolling interest is the portion of equity in a subsidiary not attributable, directly or indirectly, to a parent. We adopted SFAS No. 160 effective January 1, 2009.

Specifically, SFAS No. 160 establishes 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 (our consolidated net income and comprehensive income are now determined without deducting minority interest; however, our earnings-per-unit information continues to be calculated on the basis of the net income attributable to our limited partners). The provisions of this Statement apply prospectively; however, the presentation and disclosure requirements are to be applied retrospectively for all periods presented.

SFAS No. 161

On March 19, 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities." This Statement amends SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" and provides for enhanced disclosure requirements that include, among other things, (i) a tabular summary of the fair value of derivative instruments 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 instruments. This Statement was adopted by us effective January 1, 2009, and the adoption of this Statement did not have a material impact on our consolidated financial statements.

EITF 07-4

In March 2008, the Emerging Issues Task Force reached a consensus on Issue No. 07-4, or EITF 07-4, "Application of the Two-Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships." EITF 07-4 provides guidance for how current period earnings should be allocated between limited partners and a general partner when the partnership agreement contains incentive distribution rights. For us, this Issue was effective January 1, 2009. The guidance in this Issue is to be applied retrospectively for all financial statements presented; however, the adoption of this Issue did not have any impact on our consolidated financial statements.

FASB Staff Position No. FAS 142-3

On April 25, 2008, the FASB issued FASB Staff Position No. FAS 142-3 "Determination of the Useful Life of Intangible Assets." This Staff Position amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under SFAS No. 142, "Goodwill and Other Intangible Assets". For us, this Staff Position was effective January 1, 2009, and the adoption of this Staff Position did not have any impact on our consolidated financial statements.

FASB Staff Position No. EITF 03-6-1

On June 16, 2008, the FASB issued FASB Staff Position No. EITF 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities." This Staff Position clarifies 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. For us, this Staff Position was effective January 1, 2009, and the adoption of this Staff Position did not have any impact on our consolidated financial statements.

FASB Staff Position No. FAS 157-3

On October 10, 2008, the FASB issued FASB Staff Position No. FAS 157-3 "Determining the Fair Value of a Financial Asset When the Market for that Asset is Not Active." This Staff Position provides guidance clarifying how SFAS No. 157, "Fair Value Measurements" should be applied when valuing securities in markets that are not active. This Staff Position applies the objectives and framework of SFAS No. 157 to determine the fair value of a financial asset in a market that is not active, and it reaffirms 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. This Staff Position became effective upon issuance, and did not have any material effect on our consolidated financial statements.

EITF 08-6

On November 24, 2008, the Financial Accounting Standards Board ratified the consensus reached by the Emerging Issues Task Force on Issue No. 08-6, or EITF 08-6, "Equity Method Investment Accounting Considerations." EITF 08-6 clarifies certain accounting and impairment considerations involving equity method investments. For us, this Issue was effective January 1, 2009, and the adoption of this Issue did not have any impact on our consolidated financial statements.

FASB Staff Position No. FAS 132(R)-1

On December 30, 2008, the FASB issued FASB Staff Position No. FAS 132(R)-1, "Employer's Disclosures About Postretirement Benefit Plan Assets." This Staff Position is effective for financial statements ending after December 15, 2009 (December 31, 2009 for us) and requires additional disclosure of pension and post retirement 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. We do not expect this Staff Position to have a material impact on our consolidated financial statements.

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.

FASB Staff Position No. FAS 157-4
FASB Staff Position No. FAS 107-1 and APB 28-1
FASB Staff Position No. FAS 115-2 and FAS 124-2

On April 9, 2009, the FASB issued three separate Staff Positions intended to provide additional application guidance and enhance disclosures regarding fair value measurements and impairments of securities. FAS 157-4, "Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly," provides guidelines for making fair value measurements more consistent with the principles presented in SFAS No. 157, "Fair Value Measurements." This Staff Position provides 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.

FAS 107-1 and APB 28-1, "Interim Disclosures about Fair Value of Financial Instruments," enhances consistency in financial reporting by increasing the frequency of fair value disclosures from annual only to quarterly, in order to provide financial statement users with more timely information about the effects of current market conditions on their financial instruments. This Staff Position requires us to disclose in our interim financial statements the fair value of all financial instruments within the scope of SFAS No. 107, "Disclosures about Fair Value of Financial Instruments," as well as the method(s) and significant assumptions we use to estimate the fair value of those financial instruments.

FAS 115-2 and FAS 124-2, "Recognition and Presentation of Other-Than-Temporary Impairments," provides additional guidance designed to create greater clarity and consistency in accounting for and presenting impairment losses on securities. This Staff Position changes (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.

These three Staff Positions are effective for interim and annual periods ending after June 15, 2009 (June 30, 2009 for us). We do not expect these Staff Positions to have a material impact on our consolidated financial statements.

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

General and Basis of Presentation

The following information should be read in conjunction with (i) our accompanying interim consolidated financial statements and related notes (included elsewhere in this report); and (ii) our consolidated financial statements, related notes and management's discussion and analysis of financial condition and results of operations included in our 2008 Form 10-K.

In addition, our financial statements and the financial information contained in this Management's Discussion and Analysis of Financial Condition and Results of Operations reflect:

- the additional $0.5 million gain we recognized in the first quarter of 2008 from the disposal 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). However, because the sale of our North System does not change the structure of our internal organization in a manner that causes a change to our reportable business segments, we included this gain within our Products Pipelines business segment disclosures presented in this report for the three months ended March 31, 2008. Except for this gain, we recorded no other financial results from the operations of the North System during the first quarter of 2008; and

- the August 28, 2008 transfer of both the 33 1/3% interest in the Express and Platte crude oil pipeline system net assets (collectively referred to in this report as the Express pipeline system) and the Jet Fuel pipeline system net assets from Knight as of the date of transfer. Accordingly, we have included the financial results of the Express and Jet Fuel pipeline systems within our Kinder Morgan Canada business segment disclosures presented in this report for all periods subsequent to August 28, 2008.

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 the 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 three months ended March 31, 2009.

Results of Operations

Consolidated

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008	Earnings Increase/(decrease)	
Earnings (Losses) before depreciation, depletion and amortization expense and amortization of excess cost of equity investments(a)	(In millions, except percentages)			
Products Pipelines(b)	$ 145.4	$ 140.7	$ 4.7	3%
Natural Gas Pipelines(c)	200.8	188.2	12.6	7%
CO_2	167.4	199.8	(32.4)	(16)%
Terminals	134.7	125.8	8.9	7%
Kinder Morgan Canada(d)	19.5	30.2	(10.7)	(35)%
Segment earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	667.8	684.7	(16.9)	(2)%
Depreciation, depletion and amortization expense	(210.2)	(158.1)	(52.1)	(33)%
Amortization of excess cost of equity investments	(1.4)	(1.4)	—	—
General and administrative expense(e)	(82.5)	(76.8)	(5.7)	(7)%
Unallocable interest expense, net of interest income(f)	(104.6)	(97.7)	(6.9)	(7)%
Unallocable income tax expense	(2.3)	—	(2.3)	n/a
Net income (loss)	266.8	350.7	(83.9)	(24)%
Net income attributable to the noncontrolling interest(g)	(2.9)	(4.0)	1.1	28%
Net income attributable to Kinder Morgan Energy Partners	$ 263.9	$ 346.7	$ (82.8)	(24)%

(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, fuel and power expenses, and taxes, other than income taxes.

(b) 2009 and 2008 amounts include decreases in income of $0.6 million and $0.8 million, respectively, resulting from unrealized foreign currency losses on long-term debt transactions. 2008 amount also includes a $0.5 million gain from the 2007 sale of our North System.

(c) 2009 amount includes a $1.3 million decrease in income resulting from unrealized mark to market gains and losses due to the discontinuance of hedge accounting at Casper Douglas.

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

(e) Includes unallocated litigation and environmental expenses. 2009 and 2008 amounts include increases of $1.4 million in non-cash compensation expense, allocated to us from Knight (we do not have any obligation, nor do we expect to pay any amounts related to these expenses). 2009 amount also includes a $0.1 million increase in expense for certain Express pipeline system acquisition costs, and a $0.6 million decrease in expense related to capitalized overhead costs associated with the 2008 hurricane season.

(f) 2009 and 2008 amounts include a $0.5 million increase in interest expense related to our January 1, 2007 Cochin Pipeline acquisition.

(g) 2009 amount includes a $0.2 million decrease in net income attributable to noncontrolling (minority) interests, related to all of the 2009 items previously disclosed in these footnotes.

Net income attributable to our partners, which includes all of our limited partner unitholders and our general partner, totaled $263.9 million ($0.15 per limited partner unit) in the first quarter of 2009, compared to $346.7 million ($0.63 per limited partner unit) in the first quarter of 2008. Our total revenues for the comparative first quarter periods were $1,786.5 million and $2,720.3 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.

Combined, segment earnings before depreciation, depletion and amortization totaled $667.8 million in the first quarter of 2009, compared to $684.7 million in the first quarter of 2008. The overall $16.9 million (2%) decrease in total segment EBDA, relative to the first three months of last year, included a $16.5 million decrease from the combined effect of the certain items described in the footnotes to the table above (combining to decrease total segment EBDA by $16.8 million in 2009 and to decrease total segment EBDA by $0.3 million in 2008). The remaining EBDA from our five business segments was essentially flat across the first quarters of 2009 and 2008, as higher earnings in 2009 from our Natural Gas Pipelines, Terminals, Products Pipelines and Kinder Morgan Canada business segments were offset by lower earnings from our CO_2 business segment, primarily as a result of lower crude prices on our unhedged volumes.

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's oil and gas producing activities are exposed to commodity price risk. That risk is primarily mitigated by a long term hedging strategy under which we have hedged the majority of our long term production. However, we do have exposure on unhedged volumes, most of which are natural gas liquids volumes.

Products Pipelines

	Three Months Ended March 31,	
	2009	2008
	(In millions, except operating statistics)	
Revenues	$ 188.2	$ 198.3
Operating expenses	(49.0)	(62.4)
Other income (expense)(a)	—	0.4
Earnings from equity investments	5.4	7.5
Interest income and Other, net-income (expense)(b)	2.8	0.5
Income tax benefit (expense)	(2.0)	(3.6)
Earnings before depreciation, depletion and amortization Expense and amortization of excess cost of equity investments	$ 145.4	$ 140.7
Gasoline (MMBbl)	95.6	97.8
Diesel fuel (MMBbl)	35.5	38.6
Jet fuel (MMBbl)	26.8	29.7
Total refined product volumes (MMBbl)	157.9	166.1
Natural gas liquids (MMBbl)	4.8	6.9
Total delivery volumes (MMBbl)(c)	162.7	173.0

(a) 2008 amount includes a $0.5 million gain from the 2007 sale of our North System.

(b) 2009 and 2008 amounts include decreases in income of $0.6 million and $0.8 million, respectively, resulting from unrealized foreign currency losses on long-term debt transactions.

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

Combined, the certain items described in the footnotes to the table above account for a $0.3 million decrease in the change in the segment's earnings before depreciation, depletion and amortization expenses between the first quarter of 2009 and the first quarter of 2008. Following is information related to the increases and decreases of the segment's (i) remaining $5.0 million (4%) increase in earnings before depreciation, depletion and amortization expense (EBDA); and (ii) its $10.1 million (5%) decrease in operating revenues:

Three months ended March 31, 2009 versus Three months ended March 31, 2008

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
West Coast Terminals	$ 5.7	50%	$ 4.6	26%
Central Florida Pipeline	2.5	25%	3.1	26%
Cochin Pipeline System	1.1	11%	(3.7)	(26)%
Plantation Pipeline	(2.1)	(18)%	(6.1)	(55)%
Pacific operations	(1.1)	(2)%	(4.9)	(5)%
All others (including eliminations)	(1.1)	(3)%	(3.1)	(6)%
Total Products Pipelines	$ 5.0	4%	$ (10.1)	(5)%

The earnings growth from our Products Pipelines business in the first quarter of 2009 was driven by higher rates and asset expansions at our West Coast Terminals, and by higher ethanol revenues on our Central Florida Pipeline. Ongoing weak economic conditions continued to dampen demand for refined petroleum products at many of our remaining assets in this segment, resulting in lower revenues and volumes relative to the first quarter of 2008. However, that impact was partially offset by lower fuel and power expenses, by lower outside services and other discretionary operating expenses, and by negotiating new service contracts or bidding work at lower prices compared to last year.

Total segment operating expenses, which include costs of sales, operations and maintenance expenses, fuel and power expenses and taxes, other than income taxes decreased $13.4 million (21%) in the first quarter of 2009, when compared to the first quarter of 2008. Also in the first quarter of 2009, we entered into certain commercial agreements with several customers to ship biodiesel on a portion of the Plantation Pipeline beginning in April 2009.

The quarter-to-quarter earnings increase from our West Coast terminal operations was largely revenue related, driven by higher revenues from 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 first quarter of 2008. Revenues at our Carson/Los Angeles terminal complex increased $3.5 million in the first quarter of 2009, mainly due to increased warehouse charges resulting from customer contract revisions made since the first quarter a year ago. Revenues from our remaining West Coast facilities increased $1.1 million, due mostly to additional throughput and storage services associated with renewable fuels (both ethanol and biodiesel).

The earnings increase from our Central Florida Pipeline was driven by incremental ethanol revenues, resulting from capital expansion projects that provided ethanol storage and terminal service beginning in mid-April 2008 at our Tampa and Orlando terminals.

Compared to the first quarter last year, earnings before depreciation, depletion and amortization from our Cochin pipeline system also increased in the first quarter of 2009, despite a 26% drop in revenues largely attributable to lower propane delivery volumes in the three-month 2009 period. In the first quarter of 2009, total throughput volumes on the Cochin pipeline system declined 18% compared to the prior year first quarter, due primarily to propane supply constraints in Western Canada. The $3.7 million decrease in revenues, however, was more than offset by decreases in operating expenses and higher other income.

The overall increase in segment earnings before depreciation, depletion and amortization in the first quarter of 2009 compared to the first quarter of 2008 also included period-to-period decreases in earnings from both our equity investment in Plantation and from our Pacific operations. The segment’s $2.1 million (28%) decrease in earnings from equity investments relates to lower net income earned by Plantation Pipe Line Company. Plantation’s lower net income was chiefly attributable to lower oil loss allowance revenues in the first quarter of 2009, relative to last year, reflecting the decline in refined product market prices since the end of the first quarter of 2008.

Combining all of the segment’s operations, total revenues from refined petroleum products deliveries decreased 3.4% in the first quarter of 2009, while total products delivery volumes decreased 4.9%, when compared to the first quarter of 2008. Excluding Plantation total refined products delivery revenues were down 2% and volumes were down 7.4%, when compared to last year. Total gasoline delivery volumes decreased 2.3% (primarily on our Pacific operations), diesel volumes decreased 7.9%, and jet fuel volumes decreased 9.6%, respectively, in the first quarter of

2009 compared to the first quarter of 2008. Natural gas liquids delivery volumes decreased by 30% in the first quarter of 2009 compared to the first quarter last year, chiefly due to lower propane deliveries on the Cochin Pipeline (discussed above) and to lower liquids deliveries from our Cypress Pipeline.

Natural Gas Pipelines

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
	(In millions, except operating statistics)	
Revenues	$ 1,051.7	$ 1,912.5
Operating expenses(a)	(890.5)	(1,745.1)
Other income (expense)	—	—
Earnings from equity investments	26.6	23.5
Interest income and Other, net-income (expense)	14.7	0.2
Income tax benefit (expense)	(1.7)	(2.9)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 200.8	$ 188.2
Natural gas transport volumes (Trillion Btus)(b)	545.2	495.4
Natural gas sales volumes (Trillion Btus)(c)	203.7	215.0

(a) 2009 amount includes a $1.3 million decrease in income resulting from unrealized mark to market gains and losses due to the discontinuance of hedge accounting at Casper Douglas.
(b) Includes Kinder Morgan Interstate Gas Transmission LLC, Trailblazer Pipeline Company LLC, TransColorado Gas Transmission Company LLC, Rockies Express Pipeline LLC, and Texas intrastate natural gas pipeline group pipeline volumes.
(c) Represents Texas intrastate natural gas pipeline group volumes.

As described in footnote (a) to the table above, our Natural Gas Pipelines business segment's earnings before depreciation, depletion and amortization expenses in the first quarter of 2009 included a $1.3 million decrease due to a net unrealized mark to market loss resulting from the removal of hedge designation on certain derivative contracts used to mitigate the price risk associated with future sales of natural gas liquids by our Casper and Douglas natural gas processing operations. Following is information related to the increases and decreases, in the first quarter of 2009 compared to the first quarter of 2008, of the segment's (i) remaining $13.9 million (7%) increase in earnings before depreciation, depletion and amortization expense (EBDA); and (ii) its $860.8 million (45%) decrease in operating revenues:

Three months ended March 31, 2009 versus Three months ended March 31, 2008

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Kinder Morgan Louisiana Pipeline	$ 8.6	n/a	$ —	n/a
Rockies Express Pipeline	4.7	31%	—	—
Kinder Morgan Interstate Gas Transmission	4.2	16%	1.4	4%
Texas Intrastate Natural Gas Pipeline Group	(1.8)	(2)%	(841.2)	(47)%
Thunder Creek	(1.2)	(100)%	—	n/a
All others	(0.6)	(2)%	(23.4)	(34)%
Intrasegment Eliminations	—	—	2.4	91%
Total Natural Gas Pipelines	$ 13.9	7%	$ (860.8)	(45)%

The overall increase in segment earnings before depreciation, depletion and amortization expenses in the three months ended March 31, 2009, when compared to the same period last year, was driven primarily by incremental earnings from our Kinder Morgan Louisiana Pipeline, incremental contributions from our 51% equity ownership interest in the Rockies Express Pipeline, and higher earnings from our Kinder Morgan Interstate Gas Transmission pipeline system, commonly referred to as KMIGT.

The incremental earnings before depreciation, depletion and amortization expenses from our Kinder Morgan Louisiana Pipeline reflects other non-operating income realized in the first quarter of 2009 pursuant to FERC regulations governing allowances for capital funds that are used for pipeline construction costs (an equity cost of capital allowance). The equity cost of capital allowance provides for a reasonable return on construction costs that are funded by equity contributions, similar to the allowance for capital costs funded by borrowings.

The incremental earnings from our equity investment in the Rockies Express joint venture pipeline relates to higher net income earned by Rockies Express Pipeline LLC, primarily due to incremental earnings attributable to its Rockies Express-West natural gas pipeline segment, which began full operations in May 2008. Transport volumes for the entire Rockies Express Pipeline increased 66% in the first quarter of 2009, when compared to the first quarter last year, and this increase was primarily due to the full operations of Rockies Express-West.

The increase in earnings from our KMIGT natural gas pipeline system reflects a higher period-to-period operating margin, driven by higher firm transportation demand fees and higher pipeline fuel recoveries, relative to the first quarter a year ago. The increase in demand fees was mainly due to higher asset optimization (better balancing of available natural gas transportation capacity with market demand and pricing), and the higher fuel recoveries were primarily due to timing differences on the volumes of gas recovered due to fuel use, loss, and unaccounted for delivery differences.

The segment's overall increase in earnings before depreciation, depletion and amortization expenses in the first quarter of 2009 was partly offset by lower earnings from our Texas intrastate natural gas pipeline group, and by the lack of earnings from our previous equity investment in Thunder Creek Gas Services, LLC. We sold our 25% ownership interest in Thunder Creek to a third party in April 2008, and we received cash proceeds, net of closing costs and settlements, of approximately $50.7 million for our investment.

Our Texas intrastate natural gas pipeline group includes the operations of the Kinder Morgan Tejas (including Kinder Morgan Border Pipeline), Kinder Morgan Texas Pipeline, Kinder Morgan North Texas Pipeline and the Mier-Monterrey Mexico Pipeline, and although combined earnings from the intrastate group dropped $1.8 million (2%) in the first quarter of 2009 compared to the first quarter of 2008, the group's combined earnings accounted for more than half (53% and 58%, respectively) of our Natural Gas Pipelines segment's total earnings before depreciation, depletion and amortization expenses in each of the first three months of 2009 and 2008.

The intrastate group's decrease in earnings in the first quarter of 2009 was mainly attributable to lower margins from natural gas sales and processing activities, but partially offset by higher earnings from both natural gas storage activities and transportation demand fees. In the first quarter of 2009, the intrastate group benefitted from several new storage and transport demand fee contracts.

CO_2

	Three Months Ended March 31,	
	2009	2008
	(In millions, except operating statistics)	
Revenues	$ 228.9	$ 286.4
Operating expenses	(66.6)	(90.7)
Other income (expense)	—	—
Earnings from equity investments	5.8	5.6
Other, net-income (expense)	—	(0.2)
Income tax benefit (expense)	(0.7)	(1.3)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 167.4	$ 199.8
Carbon dioxide delivery volumes (Bcf)(a)	212.8	180.2
SACROC oil production (gross)(MBbl/d)(b)	30.0	27.3
SACROC oil production (net)(MBbl/d)(c)	25.0	22.8
Yates oil production (gross)(MBbl/d)(b)	26.5	28.6
Yates oil production (net)(MBbl/d)(c)	11.7	12.7
Natural gas liquids sales volumes (net)(MBbl/d)(c)	8.9	9.5
Realized weighted average oil price per Bbl(d)(e)	$ 43.85	$ 50.03
Realized weighted average natural gas liquids price per Bbl(e)(f)	$ 28.10	$ 65.93

(a) Includes Cortez, Central Basin, Canyon Reef Carriers, Centerline and Pecos pipeline volumes.
(b) 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.
(c) Net to Kinder Morgan, after royalties and outside working interests.
(d) Includes all Kinder Morgan crude oil production properties.
(e) Hedge gains/losses for crude oil and natural gas liquids are included with crude oil.
(f) Includes production attributable to leasehold ownership and production attributable to our ownership in processing plants and third party processing agreements.

The 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. For each of the segment's two primary businesses, following is information related to the quarter-to-quarter increases and decreases of the segment's (i) earnings before depreciation, depletion and amortization (EBDA); and (ii) operating revenues:

Three months ended March 31, 2009 versus Three months ended March 31, 2008

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Sales and Transportation Activities	$ (6.7)	(10)%	$ (6.0)	(8)%
Oil and Gas Producing Activities	(25.7)	(19)%	(55.2)	(24)%
Intrasegment Eliminations	—	—	3.7	21%
Total CO_2	$ (32.4)	(16)%	$ (57.5)	(20)%

Our CO_2 segment's overall quarter-to-quarter decrease in segment earnings before depreciation, depletion and amortization expenses in 2009 versus 2008 was primarily due to lower earnings from oil and gas producing activities, which include the operations associated with its ownership interests in oil-producing fields and natural gas processing plants. The decrease in earnings from oil and gas producing activities was driven by a $51.3 million (23%) decrease in combined crude oil and natural gas plant products sales revenues due to lower realized prices in the first quarter of 2009, when compared to the first quarter a year ago.

Overall, the segment's average realization for crude oil in the first quarter of 2009 decreased 12% when compared to the first quarter of 2008 (from $50.03 per barrel in 2008 to $43.85 per barrel in 2009). The average natural gas liquids realization decreased 57% in the first quarter of 2009, when compared to the first quarter of 2008 (from $65.93 per barrel in 2008 to $28.10 per barrel in 2009).

The quarter-to-quarter decrease in revenues from lower realized weighted average prices was partly offset by an over 2% increase in sales volumes in 2009 versus 2008 and lower operating expenses. An increase in average gross oil production at SACROC more than offset a decline at Yates and in natural gas liquids. SACROC averaged 30.0 thousand barrels per day for the first quarter of 2009, up nearly 10% compared to the first quarter of 2008. At Yates, average gross oil production for the first quarter of 2009 declined by 7% versus the same quarter last year and natural gas liquids products volumes decreased over 6%. The decrease in volumes was partly due to the lingering effects from the 2008 hurricane season, which resulted in pipeline pro-rationing (production allocation) in January 2009.

Our CO_2 segment is exposed to commodity price risk related to the price volatility of crude oil and natural gas liquids. To some extent, we are able to mitigate this risk through a long-term hedging strategy that is intended to generate more stable realized prices by using derivative contracts. Nonetheless, decreases in the prices of crude oil and natural gas liquids will have a negative impact on the result of our CO_2 business segment, and even though we hedge the majority of our crude oil production, we do have exposure to unhedged volumes, the majority of which are natural gas liquids volumes.

All of our hedge gains and losses for crude oil and natural gas liquids are included in our realized average price for oil, and had we not used energy derivative contracts to transfer commodity price risk, our crude oil sales prices would have averaged $38.48 per barrel in the first quarter of 2009, and $96.91 per barrel in the first quarter of 2008.

For more information on our hedging activities, see Note 10 to our consolidated financial statements included elsewhere in this report.

The quarter-to-quarter decrease in earnings before depreciation, depletion and amortization from the segment's sales and transportation activities was also largely revenue related, reflecting both a $2.3 million decrease in carbon dioxide and crude oil pipeline transportation revenues and a $2.8 million decrease in earnings from lower asset sales (due to the sale of certain pipeline meters in March 2008). The decrease in pipeline transportation revenues was largely due to lower transport revenues in the first quarter of 2009 from our Wink crude oil pipeline and our Central Basin carbon dioxide pipeline. The decrease in Wink revenues was due to favorable pipeline imbalance adjustments realized in the first quarter of 2008, and the decrease in Central Basin revenues was mainly due to a favorable transportation settlement reached with a pipeline customer in the first quarter of 2008.

Revenues from carbon dioxide sales to third parties were essentially flat across the first quarters of 2009 and 2008 (decreasing by only $1.0 million (2%) in 2009 versus 2008), and we do not recognize profits on carbon dioxide sales to ourselves. Quarter-to-quarter carbon dioxide delivery volumes increased 18% in 2009, due to both incremental volumes attributable to expansion projects completed since the end of the first quarter of 2008, and incremental volumes from the Doe Canyon carbon dioxide source field located in Dolores County, Colorado, which began operations in mid-January 2008.

Compared to the first quarter of 2008, the segment's $24.1 million (27%) decrease in combined operating expenses in the first quarter of 2009 was largely due to a $9.9 million (47%) decrease in severance and property tax expenses, a $7.5 million (32%) decrease in fuel and power expenses, and a $5.6 million (13%) decrease in field operating expenses. The decrease in severance tax expenses was primarily related to the period-to-period decrease in crude oil revenues. The decreases in fuel, power, and other operating expenses were largely related to lower prices charged by the industry's material and service providers since the end of the first quarter of 2008, which impacted rig costs and other materials and services. The drop in price levels was primarily due to the same external factors that impacted sales revenues—as price levels for such expenses (and capital and exploratory costs) are largely driven by the volatility of the industry's own supply and demand conditions.

Terminals

	Three Months Ended March 31, 2009	Three Months Ended March 31, 2008
	(In millions, except operating statistics)	
Revenues	$ 267.9	$ 280.2
Operating expenses	(133.6)	(152.8)
Other income (expense)	0.9	0.6
Earnings from equity investments	0.1	1.0
Other, net-income (expense)	(0.1)	1.3
Income tax benefit (expense)	(0.5)	(4.5)
Earnings before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 134.7	$ 125.8
Bulk transload tonnage (MMtons)(a)	18.8	23.9
Liquids leaseable capacity (MMBbl)	54.2	50.0
Liquids utilization %	97.3%	97.5%

(a) Volumes for acquired terminals are included for both periods.

Our Terminals business segment includes the operations of our petroleum, chemical and other liquids terminal facilities (other than those included in our Products Pipelines segment), and all of our coal, petroleum coke, fertilizer, steel, ores and other dry-bulk material services facilities. We group our bulk and liquids terminal operations into regions based on geographic location and/or primary operating function. This structure allows our management to organize and evaluate segment performance and to help make operating decisions and allocate resources.

The segment's $8.9 million (7%) increase in earnings before depreciation, depletion and amortization and its $12.3 million (4%) decrease in operating revenues in the first quarter of 2009 versus the first quarter of 2008 represent net changes in terminal results at various locations, and include incremental amounts of earnings and revenues of $1.0 million and $2.5 million, respectively, attributable to terminal operations we acquired since the end of the first quarter of 2008.

Following is information, by terminal operating region, related to the remaining $7.9 million (6%) increase in segment EBDA and the remaining $14.8 million (5%) decrease in segment revenues in the first quarter of 2009 versus the first quarter of 2008. These increases represent changes from the terminal operations we owned during the first three months of both comparable years.

Three months ended March 31, 2009 versus Three months ended March 31, 2008

	EBDA increase/(decrease)		Revenues increase/(decrease)	
	(In millions, except percentages)			
Mid-Atlantic	$ 4.2	62%	$ 3.8	19%
Texas Petcoke	3.4	23%	(0.8)	(2)%
Lower River (Louisiana)	3.3	41%	(2.9)	(11)%
Northeast	3.1	17%	3.5	12%
West	1.7	27%	1.9	12%
Mid River	(3.0)	(44)%	(9.0)	(41)%
Materials Services	(2.1)	(45)%	(4.6)	(35)%
Southeast	(1.8)	(17)%	(4.7)	(19)%
All others	(0.9)	(2)%	(2.0)	(2)%
Intrasegment Eliminations	—	—	—	—
Total Terminals	$ 7.9	6%	$ (14.8)	(5)%

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The overall increase in earnings before depreciation, depletion and amortization in the first quarter of 2009 from our Mid-Atlantic terminals was primarily related to our Pier IX bulk terminal located in Newport News, Virginia. The earnings increase at Pier IX was driven by higher period-to-period revenues in 2009, due to higher average coal transfer rates and to incremental coal transfer revenues that were partly related to an expansion project completed in the first quarter of 2008.

The increase in earnings from our Texas Petcoke terminals, which primarily handle petroleum coke tonnage in and around the Texas Gulf Coast, was mainly due to higher petroleum coke throughput volumes and higher handling rates at our Port of Houston and Port Arthur, Texas terminal locations, when compared to the first quarter last year. The period-to-period increases in the Texas terminals' petcoke shipments were mainly related to higher production volumes in 2009, and partly related to a refinery shutdown in the first quarter of 2008.

The quarter-to-quarter earnings increase from our Lower River (Louisiana) terminals was largely associated with the segment's $4.0 million (89%) decrease in income tax expense due to lower taxable income in our tax paying subsidiaries in the first quarter of 2009, when compared to last year's first quarter. We also realized quarter-to-quarter earnings increases from our Northeast and West terminals, primarily due to expansion projects at our Kinder Morgan North 40 terminal, and at our three New York Harbor liquids terminals: our Perth Amboy, New Jersey terminal; our Carteret, New Jersey terminal; and our Staten Island, New York terminal. Overall, our liquids terminal operations benefited from an over 8% (4.2 million barrels) increase in liquids leasable capacity since the end of the first quarter of 2008, with most of the increase coming from internal capital investment driven by continued strong demand for imported fuel. At the same time we increased storage capacity, our overall liquids utilization capacity rate (the ratio of our actual leased capacity to our estimated potential capacity) remained essentially flat across both comparable quarters.

The overall increase in segment earnings before depreciation, depletion and amortization from terminals owned during the first three months of both comparable years was partly offset by lower earnings from our Mid River terminals, our Materials Services (rail-transloading) facilities, and our Southeast bulk terminals. The decreases in earnings and revenues were primarily driven by decreased import/export activity, and by 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.

For our Terminals segment combined, first quarter 2009 bulk traffic tonnage was down 5.1 million tons (21%) compared to the first quarter of 2008. While tonnage and operating results vary by region and terminal, the decrease in bulk tonnage volume was generally due to the economic contraction that began last year. The economic downturn negatively affected the worldwide steel industry and has led to a general decrease in U.S. port activity, relative to the first quarter last year. As a result, domestic and overseas vessel traffic trailed year-earlier levels and throughput volumes for steel, metal ores, and construction materials declined, when compared to the first quarter of 2008.

Kinder Morgan Canada

	Three Months Ended March 31,	
	2009	2008
	(In millions, except operating statistics)	
Revenues	$ 50.0	$ 43.1
Operating expenses	(15.2)	(15.7)
Other income (expense)	—	2.1
Earnings from equity investments	0.3	0.1
Interest income and Other, net-income (expense)	0.7	—
Income tax benefit (expense)(a)	(16.3)	0.6
Earnings (Losses) before depreciation, depletion and amortization expense and amortization of excess cost of equity investments	$ 19.5	$ 30.2
Trans Mountain Transport volumes (MMBbl)	24.8	19.5

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

Our Kinder Morgan Canada business segment includes the operations of the Trans Mountain, Express, and Jet Fuel pipeline systems. We acquired the net assets of the Trans Mountain pipeline system from Knight effective April 30, 2007, and as described above in "—General and Basis of Presentation," we acquired both our one-third equity ownership interest in the approximate 1,700-mile Express pipeline system and our full ownership of the approximate 25-mile Jet Fuel pipeline system from Knight effective August 28, 2008. Combined, these businesses accounted for incremental earnings before depreciation, depletion and amortization of $4.0 million, and incremental revenues of $0.7 million in the first quarter of 2009.

For the segment's remaining business—the Trans Mountain crude oil and refined products pipeline system, earnings remained essentially flat across the comparable first quarter periods (increasing by $0.2 million in first quarter 2009 versus first quarter 2008), excluding the $14.9 million decrease in earnings before depreciation, depletion and amortization expenses in the first quarter of 2009 as a result of the certain non-cash item described in footnote (a) to the table above. The slight increase in earnings was driven by a $6.2 million (14%) increase in operating revenues in the first quarter of 2009, largely offset by both a $3.7 million drop in income from the allowance for equity funds used during construction and a $2.2 increase in period-to-period income tax expenses. The segment's $0.5 million (3%) drop in operating expenses in the first quarter of 2009 was largely offset by higher foreign currency losses.

The increase in Trans Mountain's operating revenues reflect a 27% increase in mainline throughput volumes, due primarily to expansion projects completed since the end of the first quarter of 2008 that increased pipeline transportation capacity. On both April 28th and October 30th of 2008, we completed separate portions of the pipeline's Anchor Loop expansion project and combined, this project boosted pipeline 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 March 31, 2009	2008	Earnings increase/(decrease)	
	(In millions-income (expense), except percentages)			
General and administrative expenses(a)	$ (82.5)	$ (76.8)	$ (5.7)	(7%)
Unallocable interest expense, net of interest income(b)	$ (104.6)	$ (97.7)	$ (6.9)	(7%)
Unallocable income tax benefit (expense)	(2.3)	—	(2.3)	n/a
Net income attributable to the noncontrolling interest(c)	(2.9)	(4.0)	1.1	28%
Total interest, income tax and minority interest	$ (109.8)	$ (101.7)	$ (8.1)	(8%)

(a) Includes such items as salaries and employee-related expenses, payroll taxes, insurance, office supplies and rentals, unallocated litigation and environmental expenses, and shared corporate services. 2009 and 2008 amounts include increases of $1.4 million in non-cash compensation expense allocated to us from Knight. We do not have any obligation, nor do we expect, to pay any amounts related to these expenses. 2009 amount also includes a $0.1 million increase in expense for certain Express pipeline system acquisition costs, and a $0.6 million decrease in expense related to capitalized overhead costs associated with the 2008 hurricane season.

(b) 2009 and 2008 amounts include increases in imputed interest expense of $0.5 million related to our 2007 Cochin Pipeline acquisition.

(c) 2009 amount includes a $0.2 million decrease in net income attributable to noncontrolling (minority) interests, related to all of the 2009 items previously disclosed in the footnotes to the tables included in "—Results of Operations."

Items not attributable to any segment include general and administrative expenses, unallocable interest income and income tax expense, interest expense, and net income attributable to noncontrolling interests. For the comparable three month periods, the certain items described in footnote (a) to the table above decreased general and administrative expenses by $0.5 million in 2009, when compared to the first quarter last year.

The remaining $6.2 million (8%) increase in general and administrative expenses includes a $3.1 million increase due to a drop in capitalized overhead expenses, compared to the first quarter a year ago. The decrease in capitalized costs during the first quarter of 2009 was due primarily to lower overall spending on capital projects. The increase in corporate expenses also includes an approximately $2.7 million increase from higher employee benefit and payroll tax expenses in the first quarter of 2009, due to both higher expense and to timing differences. The increases in expenses were associated with our larger year-over-year asset base, which has grown since the end of the first quarter of 2008 due to both completions of certain capital expansion and improvement projects and acquisitions of business operations. Strategic business operations acquired since the end of the first quarter of 2008 include our ownership interests in the Express (one-third) and Jet Fuel pipeline systems acquired from Knight, and certain bulk and liquids terminal operations acquired from third parties.

We continue to manage aggressively our infrastructure expenses, and in light of the current economic uncertainties, we have taken additional measures to reduce our general and administrative expenses since the start of the year. Specifically, we are reducing our travel costs and compensation costs, 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.

In February 2009, Knight amended its Knight Inc. Cash Balance Retirement Plan in order to reduce its rate of future benefit accruals effective April 12, 2009. Beginning on that date, and continuing through the end of the year, Knight (and we) ceased making contribution credits to the accounts of all participating employees of KMGP Services, Inc. and Knight Inc. (which, in addition to our subsidiary Kinder Morgan Canada Inc., employ all persons necessary for the operation of our businesses) under the cash balance portion of the plan, except to the extent the terms of an applicable collective bargaining agreement require contribution credits be made.

The $6.9 million (7%) increase in interest expense in 2009 compared to 2008 was attributable to an over 17% increase in our average debt balances, partially offset by an 11% decrease in the weighted average interest rate on all of our borrowings. The decrease in our average borrowing rate reflects a general decrease in variable interest rates since March 2008. As of March 31, 2009, approximately 43% of our $8,742.7 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.

The increase in our average borrowings for the comparable three month periods was largely due to the capital expenditures we have made since the end of the first quarter of 2008, driven primarily by continued investment in our Natural Gas Pipelines (including payments for pipeline project construction costs) and CO_2 business segments. Generally, we initially fund both our discretionary capital spending and our acquisition outlays from borrowings under our long-term revolving bank credit facility (or under our commercial paper program when we have access to the commercial paper market). From time to time, we issue senior notes and equity in order to refinance our commercial paper and credit facility borrowings.

The incremental unallocable income tax expense in the first quarter of 2009 relates to a corporate income tax accrual (accrued by the Partnership) for the Texas margin tax, an entity-level tax imposed on the amount of our total revenue that is apportioned to the state of Texas. The increase in our earnings due to lower net income allocated to noncontrolling interests relates to lower overall partnership income in the first quarter of 2009 versus the first quarter of 2008.

Financial Condition

General

As of March 31, 2009, we believe our balance sheet and liquidity position remained strong. Cash on hand was $65.5 million, and we demonstrated continued access to the equity market by raising $287.9 million in cash from the sales of additional common units during the first quarter of 2009. Also, in January 2009, we terminated an existing fixed-to-variable interest rate swap agreement on a notional amount of $300 million of our 7.40% senior notes due March 15, 2031, and received proceeds of $144.4 million.

In addition to the above, our diverse set of energy assets generated $452.4 million in cash from operations in the first quarter 2009, and as of March 31, 2009, we had approximately $1.06 billion of borrowing capacity available under our $1.85 billion bank credit facility (discussed below in "—Short-term Liquidity"). Furthermore, at Knight's third quarter 2008 board meeting held on October 15, 2008, Knight's board indicated its willingness to contribute up to $750 million of equity to us over the subsequent 18 months, if necessary, in order to support our capital raising efforts. We believe that our cash generating business model provides us with the financial flexibility needed to operate our assets and make targeted investments in the business segments that present our best long-term opportunities, and as we continue to operate in the current challenging economic environment, we will also continue to focus on cost and expense reduction and improved efficiency.

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 addition to utilizing cash generated from operations, we could meet our cash requirements for expansion capital expenditures through borrowings under our credit facility, issuing long-term notes or additional common units or the proceeds from purchases of additional i-units by KMR with the proceeds from issuances of additional KMR shares.

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 S&P, 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. One Lehman entity was a lending institution that provided $63.3 million of our credit facility. During the first quarter of 2009, we amended our facility to remove Lehman as a lender, thus reducing the facility by $63.3 million. The commitments of the other banks remain unchanged, and the facility is not defaulted.

On October 13, 2008, S&P 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, S&P lowered our short-term credit rating to A-3 from A-2. As a result of the revision to our short-term credit rating and the current commercial paper market conditions, we are unable to access commercial paper borrowings; however, all ratings remain unchanged since December 31, 2008 and we expect that our financing and our short-term liquidity needs will continue to be met through borrowings made under our long-term 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 five-year senior unsecured revolving bank credit facility that matures August 18, 2010; and (ii) cash from operations (discussed below in "—Operating Activities"). Borrowings under our five-year 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 up to $2.04 billion (after reductions by the Lehman commitment). As of March 31, 2009, the outstanding balance under our five-year credit facility was $439.8 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.

As of March 31, 2009, our outstanding short-term debt was $484.9 million, primarily consisting of the $439.8 million of outstanding borrowings under our bank credit facility. We provide for additional liquidity by maintaining a sizable amount of excess borrowing capacity related to our long-term revolving bank credit facility. After reduction for (i) our letters of credit; (ii) our outstanding borrowings under our revolving credit facility; and (iii) the lending commitments made by a Lehman Brothers related bank, the remaining available borrowing capacity under our bank credit facility was $1,056.9 million as of March 31, 2009. Currently, we believe our liquidity to be adequate.

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. For information on all of our first quarter 2009 equity issuances, including cash proceeds received from both a standby equity distribution agreement and a public offering of common units, see Note 8 "Partners' Capital—Equity Issuances" to our consolidated financial statement included elsewhere in this report.

As of March 31, 2009 and December 31, 2008, the total liability balance due on the various series of our senior notes was $8,132.0 million and $8,381.5 million, respectively, and the total liability balance due on the various borrowings of our operating partnerships and subsidiaries was $170.9 million and $182.1 million, respectively. For more information on our first quarter 2009 debt related transactions, see Note 7 "Debt" to our consolidated financial statements included elsewhere in this report. For additional information regarding our debt securities and credit facility, and Note 9 to our consolidated financial statements included in our 2008 Form 10-K.

We are subject, however, to changes 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 other debt financing alternatives, some of which could involve higher costs or negatively affect our credit ratings. Furthermore, our ability to access the public and private debt markets is affected by our credit ratings. See "—Credit Ratings and Capital Market Liquidity" above for a discussion of our credit ratings.

Capital Structure

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

With respect to our debt, we target a debt mixture of approximately 50% fixed and 50% variable. 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 $420.3 million in the first three months of 2009, versus $628.1 million in the same year-ago period. Our sustaining capital expenditures, defined as capital expenditures which do not increase the capacity of an asset, were $29.4 million for the first quarter of 2009, compared to $29.9 million for the first quarter of 2008. These sustaining expenditure amounts include our proportionate share of Rockies Express' sustaining capital expenditures—less than $0.1 million in each of the first quarters of 2009 and 2008. Additionally, our forecasted expenditures for the remaining nine months of 2009 for sustaining capital expenditures are approximately $152.7 million—including $0.4 million for our proportionate share of Rockies 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 member 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 quarters of 2009 and 2008 were $390.9 million and $598.2 million, respectively. Generally, we fund our discretionary capital expenditures (and our investment contributions) through borrowings under our revolving 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 quarter of 2009, we used sales of common units to refinance portions of our short-term borrowings under our bank credit facility.

Operating Activities

Net cash provided by operating activities was $452.4 million for the three months ended March 31, 2009, versus $306.9 million for the comparable period of 2008. The period-to-period increase of $145.5 million (47%) in cash provided by operating activities primarily consisted of:

- 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 $32.4 million increase related to higher distributions received from equity investments—chiefly due to $35.2 million of distributions received in the first quarter of 2009 from our investment in West2East Pipeline LLC, the sole owner of Rockies Express Pipeline LLC. We began receiving distributions from 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;

- a $23.3 million increase in cash from FERC-mandated reparation payments made in March 2008. Pursuant to FERC orders, we made reparation payments of $23.3 million to certain shippers on our Pacific operations' pipelines and we reduced our rate case liability. The payments primarily related to a FERC ruling in February 2008 that resolved certain challenges by complainants with regard to delivery tariffs and gathering enhancement fees at our Pacific operations' Watson Station, located in Carson, California;

- a $41.6 million decrease in cash from overall lower partnership income—after adjusting for certain non-cash items including depreciation, depletion and amortization expenses, undistributed earnings from equity investees, and income from the allowance for equity funds used during construction. The drop in partnership income reflects the overall decrease in cash earnings from our five reportable business segments in the first quarter of 2009, as discussed above in "—Results of Operations" (including all of the certain items disclosed in the associated table footnotes); and

- a $10.1 million decrease in cash inflows relative to net changes in working capital items, reflecting changes in both trade and related party receivables and payables, and all other current assets and liabilities. The overall decrease from working capital items included a $19.8 million decrease in cash due to higher interest payments in the first quarter of 2009.

Investing Activities

Net cash used in investing activities was $503.4 million for the three month period ended March 31, 2009, compared to $981.0 million for the comparable 2008 period. The $477.6 million (49%) decrease in cash used in investing activities was primarily attributable to:

- a $207.8 million decrease in cash used due to lower capital expenditures in the first quarter of 2009—largely due to the increased investment undertaken in the first quarter of 2008 to construct our Kinder Morgan Louisiana Pipeline and to expand our Trans Mountain crude oil and refined petroleum products pipeline system;

- a $162.5 million decrease in cash used due to lower contributions paid to equity investees in the first quarter of 2009, relative to the first quarter last year. As discussed in Note 2 to our consolidated financial statements included elsewhere in this report, in the first quarter of 2009 we contributed a combined $171.0 million to West2East Pipeline LLC, Midcontinent Express Pipeline LLC, and Fayetteville Pipeline LLC to partially fund their respective Rockies Express, Midcontinent Express, and Fayetteville Express Pipeline construction and/or pre-construction costs. In the first quarter of 2008, we contributed a combined $333.5 million to West2East Pipeline LLC and Midcontinent Express Pipeline LLC to partially fund their respective Rockies Express and Midcontinent Express Pipeline construction costs. In general, the capital expenditures for these two pipeline projects are being funded by borrowings under Rockies Express' and Midcontinent Express' own revolving credit facilities, or by those entities issuing long-term notes or receiving equity infusions from us. Furthermore, in May 2009, we expect to contribute an additional $22.2 million to Fayetteville Express Pipeline LLC;

- a $98.1 million decrease in cash used due to repayments received, in the first quarter of 2009, from a $109.6 million loan we made in December 2008 to a single customer of our Texas intrastate natural gas pipeline group. We expect to receive payment for the remaining $11.5 million loan balance in the second quarter of 2009;

- a $93.0 million decrease in cash used due to lower 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; and

- an $89.1 million increase in cash used related to a return of capital received from Midcontinent Express Pipeline LLC in the first quarter of 2008. In February 2008, 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.

Financing Activities

Net cash provided by financing activities amounted to $54.9 million for the first quarter of 2009. For the first quarter a year ago, our financing activities provided net cash of $689.2 million. The $634.3 million (92%) cash decrease from the comparable 2008 period was mainly due to:

- a $410.5 million decrease in cash from overall debt financing activities—which include our issuances and payments of debt and our debt issuance costs. The period-to-period decrease in cash from overall financing activities was primarily due to (i) a $1,144.1 million decrease in cash due to lower net issuances and payments of senior notes in the first quarter of 2009; (ii) a $439.8 million increase in cash from incremental borrowings under our long-term revolving bank credit facility in the first quarter of 2009; and (iii) a $292.4 million increase in cash from lower net commercial paper borrowings in the first quarter of 2009.

  The decrease in cash inflows from changes in senior notes outstanding reflects the combined $894.1 million we received from our February 2008 public offerings of senior notes, versus the $250.0 million we paid on February 1, 2009 to retire the principal amount of our 6.30% senior notes that matured on that date. On February 12, 2008, we completed offerings for an aggregate $900 million in principal amount of senior notes in two separate series: $600 million of 5.95% notes due February 15, 2018, and $300 million of 6.95% notes due January 15, 2038. Combined, we received proceeds, net of underwriting discounts and commissions, of $894.1 million from these long-term debt offerings and we used the proceeds from each of these offerings to reduce the borrowings under our commercial paper program.

- a $96.4 million decrease in cash from lower partnership equity issuances. The increase relates to the combined $287.9 million we received, after commissions and underwriting expenses, from the sales of additional common units in the first quarter of 2009 (discussed above in "—Long-term Financing"), versus the combined $384.3 million we received from two separate offerings of common units in the first quarter of 2008. The $384.3 million in proceeds received in the first quarter of 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 each of these two offerings to reduce the borrowings under our commercial paper program;

- an $84.4 million decrease in cash from higher partnership distributions in the first three months of 2009, when compared to the first quarter of 2008. Distributions to all partners, consisting of our common and Class B unitholders, our general partner and our minority interests, totaled $422.7 million in the first three months of 2009, compared to $338.3 million in the same period last year; and

- a $41.9 million decrease in cash inflows from net changes in cash book overdrafts—resulting from timing differences on checks issued but not yet endorsed.

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 noncontrolling (minority) interests.

On February 13, 2009, we paid a quarterly distribution of $1.05 per unit for the fourth quarter of 2008. This distribution was 14% greater than the $0.92 distribution per unit we paid in February 2008 for the fourth quarter of 2007. We paid this distribution in cash to our general partner and to our common and Class B unitholders. KMR, our sole i-unitholder, received additional i-units based on the $1.05 cash distribution per common unit. On April 15, 2009, we declared a cash distribution of $1.05 per unit for the first quarter of 2009 (an annualized rate of $4.20 per unit). This distribution was 9% higher than the $0.96 per unit distribution we made for the first quarter of 2008.

The incentive distribution that we paid on February 13, 2009 to our general partner (for the fourth quarter of 2008) was $216.6 million. Our general partner's incentive distribution that we paid in February 2008 (for the fourth quarter of 2007) was $170.3 million. Our general partner's incentive distribution for the distribution that we declared for the first quarter of 2009 will be $223.2 million, and our general partner's incentive distribution for the distribution that we paid for the first quarter of 2008 was $185.8 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 $50 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. Lower operational and capital costs and reduced general and administrative costs (along with lower interest rates) were partially realized in the first quarter of 2009, and these items are expected to further benefit us throughout the year. As a result of these cost reductions and other opportunities that we have identified, we remain confident that we will achieve our budget target of $4.20 per unit in cash distributions for 2009.

Litigation and Environmental

Please refer to Note 3 to our consolidated financial statements included elsewhere in this report for information regarding pending litigation and environmental matters, respectively.

Certain Contractual Obligations

There have been no material changes in our contractual obligations that would affect the disclosures presented as of December 31, 2008 in our 2008 Form 10-K.

Off Balance Sheet Arrangements

There have been no material changes in our obligations with respect to other entities that are not consolidated in our financial statements that would affect the disclosures presented as of December 31, 2008 in our 2008 Form 10-K.

Recent Accounting Pronouncements

Please refer to Note 16 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;

- 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 3 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 10 to our consolidated financial statements included elsewhere in this report.

Item 4. Controls and Procedures.

As of March 31, 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 March 31, 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 3 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.

In reviewing the documents included or incorporated by reference as exhibits to this report, please remember they are included to provide you with information regarding their terms and are not intended to provide any other factual information about us or any other parties to the documents. Some of the documents are agreements that contain representations and warranties by one or more of the parties of the applicable agreement. These representations and warranties were made solely for the benefit of the other parties to the applicable agreement and:

- may have been used for the purpose of allocating risk between the parties rather than establishing matters of fact;

- may have been qualified by disclosures that were made to the other party in connection with the negotiation of the applicable agreement, which disclosures are not necessarily reflected in the agreement;

- may apply standards of materiality in a way that is different from what may be viewed as material to you or other readers; and

▪ may apply only as of the date of the applicable agreement or such other date or dates as may be specified in the agreement and are subject to more recent developments.

Accordingly, investors should not rely on the representations and warranties in these agreements as characterizations of the actual state of facts about us or our business or operations on the date thereof or any other time.

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

11 -- Statement re: computation of per share earnings.

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

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

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

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

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

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

SIGNATURE

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

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

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

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

/s/ Kimberly A. Dang

Kimberly A. Dang
Vice President and Chief Financial Officer
(principal financial and accounting officer)
Date: May 1, 2009