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

FORM 10-Q

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

For the quarterly period ended September 30, 2009

OR

o 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: 1-14323

ENTERPRISE PRODUCTS PARTNERS L.P.

(Exact name of Registrant as Specified in Its Charter)

Delaware	**76-0568219**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

1100 Louisiana, 10th Floor
Houston, Texas 77002
(Address of Principal Executive Offices, Including Zip Code)

(713) 381-6500
(Registrant's Telephone Number, Including Area Code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes ☑ No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, 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 definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☑	Accelerated filer o
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes o No ☑

There were 604,716,122 common units (including 2,797,822 restricted common units) and 4,520,431 Class B units (which generally vote together with the common units) of Enterprise Products Partners L.P. outstanding at November 4, 2009. The common units trade on the New York Stock Exchange under the ticker symbol "EPD."

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PART I. FINANCIAL INFORMATION.

Item 1. ***Financial Statements*****.**

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEETS
(Dollars in millions)

ASSETS	September 30, 2009	December 31, 2008
Current assets:		
Cash and cash equivalents	$ 73.8	$ 35.4
Restricted cash	102.8	203.8
Accounts and notes receivable – trade, net of allowance for doubtful accounts of $14.4 at September 30, 2009 and $15.1 at December 31, 2008	1,471.4	1,185.5
Accounts receivable – related parties	37.9	61.6
Inventories (see Note 5)	1,147.5	362.8
Derivative assets (see Note 4)	197.0	202.8
Prepaid and other current assets	118.6	111.8
Total current assets	3,149.0	2,163.7
Property, plant and equipment, net	13,661.6	13,154.8
Investments in unconsolidated affiliates	901.0	949.5
Intangible assets, net of accumulated amortization of $492.5 at September 30, 2009 and $429.9 at December 31, 2008	793.0	855.4
Goodwill	706.9	706.9
Deferred tax asset	1.1	0.4
Other assets	144.9	126.8
Total assets	$ 19,357.5	$ 17,957.5
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable – trade	$ 327.1	$ 300.5
Accounts payable – related parties	47.2	39.6
Accrued product payables	1,675.6	1,142.4
Accrued interest payable	117.4	151.9
Other accrued expenses	46.1	48.8
Derivative liabilities (see Note 4)	263.1	287.2
Other current liabilities	220.9	252.7
Total current liabilities	2,697.4	2,223.1
Long-term debt: (see Note 9)		
Senior debt obligations – principal	7,912.3	7,813.4
Junior subordinated notes – principal	1,232.7	1,232.7
Other	53.3	62.3
Total long-term debt	9,198.3	9,108.4
Deferred tax liabilities	69.6	66.1
Other long-term liabilities	95.8	81.3
Commitments and contingencies		
Equity: (see Note 10)		
Enterprise Products Partners L.P. partners’ equity:		
Limited Partners:		
Common units (475,293,998 units outstanding at September 30, 2009 and 439,354,731 units outstanding at December 31, 2008)	6,670.8	6,036.9
Restricted common units (2,658,850 units outstanding at September 30, 2009 and 2,080,600 units outstanding at December 31, 2008)	34.1	26.2
General partner	136.6	123.6
Accumulated other comprehensive loss	(67.1)	(97.2)
Total Enterprise Products Partners L.P. partners’ equity	6,774.4	6,089.5
Noncontrolling interest	522.0	389.1
Total equity	7,296.4	6,478.6
Total liabilities and equity	$ 19,357.5	$ 17,957.5

See Notes to Unaudited Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED OPERATIONS
(Dollars in millions, except per unit amounts)

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	**2008**	**2009**	**2008**
Revenues:				
Third parties	$ 4,444.7	$ 5,997.7	$ 11,006.1	$ 17,498.4
Related parties	151.4	300.2	521.0	823.7
Total revenues (see Note 11)	4,596.1	6,297.9	11,527.1	18,322.1
Costs and expenses:				
Operating costs and expenses:				
Third parties	3,983.2	5,806.7	9,740.1	16,766.0
Related parties	237.0	165.2	655.6	477.1
Total operating costs and expenses	4,220.2	5,971.9	10,395.7	17,243.1
General and administrative costs:				
Third parties	17.1	8.4	33.5	22.4
Related parties	16.8	13.4	51.2	44.6
Total general and administrative costs	33.9	21.8	84.7	67.0
Total costs and expenses	4,254.1	5,993.7	10,480.4	17,310.1
Equity in income of unconsolidated affiliates	22.5	14.9	18.3	48.1
Operating income	364.5	319.1	1,065.0	1,060.1
Other income (expense):				
Interest expense	(128.0)	(102.7)	(374.6)	(290.4)
Interest income	0.2	2.1	1.4	4.7
Other, net	(0.2)	(0.9)	(0.5)	(1.9)
Total other expense, net	(128.0)	(101.5)	(373.7)	(287.6)
Income before provision for income taxes	236.5	217.6	691.3	772.5
Provision for income taxes	(6.6)	(6.6)	(24.0)	(17.2)
Net income	229.9	211.0	667.3	755.3
Net income attributable to noncontrolling interest	(17.0)	(7.9)	(42.5)	(29.3)
Net income attributable to Enterprise Products Partners L.P.	$ 212.9	$ 203.1	$ 624.8	$ 726.0
Net income allocated to:				
Limited partners	$ 171.3	$ 167.6	$ 504.6	$ 620.5
General partner	$ 41.6	$ 35.5	$ 120.2	$ 105.5
Basic and diluted earnings per unit (see Note 13)	$ 0.36	$ 0.38	$ 1.09	$ 1.41

See Notes to Unaudited Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED
COMPREHENSIVE INCOME (LOSS)
(Dollars in millions)

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Net income	$ 229.9	$ 211.0	$ 667.3	$ 755.3
Other comprehensive income (loss):				
Cash flow hedges:				
Commodity derivative instrument losses during period	(8.3)	(244.0)	(146.9)	(124.1)
Reclassification adjustment for losses included in net income related to commodity derivative instruments	77.8	28.5	176.3	15.8
Interest rate derivative instrument gains (losses) during period	(8.0)	(1.1)	7.1	(22.9)
Reclassification adjustment for (gains) losses included in net income related to interest rate derivative instruments	1.3	--	3.3	(2.4)
Foreign currency derivative gains (losses)	0.2	--	(10.3)	(1.3)
Total cash flow hedges	63.0	(216.6)	29.5	(134.9)
Foreign currency translation adjustment	1.1	0.4	1.7	0.5
Change in funded status of pension and postretirement plans, net of tax	--	--	--	(0.3)
Total other comprehensive income (loss)	64.1	(216.2)	31.2	(134.7)
Comprehensive income (loss)	294.0	(5.2)	698.5	620.6
Comprehensive income attributable to noncontrolling interest	(17.3)	(7.6)	(43.6)	(28.7)
Comprehensive income attributable to Enterprise Products Partners L.P.	$ 276.7	$ (12.8)	$ 654.9	$ 591.9

See Notes to Unaudited Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED CASH FLOWS
(Dollars in millions)

	For the Nine Months Ended September 30, 2009	For the Nine Months Ended September 30, 2008
Operating activities:		
Net income	$ 667.3	$ 755.3
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	476.9	413.6
Equity in income of unconsolidated affiliates	(18.3)	(48.1)
Distributions received from unconsolidated affiliates	63.6	69.9
Operating lease expense paid by EPCO, Inc.	0.5	1.5
Gain from asset sales and related transactions	(0.4)	(1.7)
Non-cash impairment charge	1.7	--
Deferred income tax expense	2.5	5.6
Changes in fair market value of derivative instruments	11.7	5.4
Effect of pension settlement recognition	(0.1)	(0.1)
Net effect of changes in operating accounts (see Note 16)	(590.0)	(228.4)
Net cash flows provided by operating activities	615.4	973.0
Investing activities:		
Capital expenditures	(851.1)	(1,485.6)
Contributions in aid of construction costs	12.8	21.2
Decrease (increase) in restricted cash	100.8	(112.2)
Cash used for business combinations	(24.5)	(57.1)
Acquisition of intangible assets	--	(5.1)
Investments in unconsolidated affiliates	(14.5)	(72.0)
Other proceeds from investing activities	5.1	1.7
Cash used in investing activities	(771.4)	(1,709.1)
Financing activities:		
Borrowings under debt agreements	3,818.9	6,360.4
Repayments of debt	(3,724.2)	(4,824.0)
Debt issuance costs	(5.2)	(8.8)
Cash distributions paid to partners	(860.6)	(770.9)
Cash distributions paid to noncontrolling interest (see Note 10)	(47.9)	(39.2)
Net cash proceeds from issuance of common units	878.2	57.2
Cash contributions from noncontrolling interest (see Note 10)	137.4	--
Acquisition of treasury units	(1.8)	(0.8)
Monetization of interest rate derivative instruments	--	(22.1)
Cash provided by financing activities	194.8	751.8
Effect of exchange rate changes on cash	(0.4)	--
Net change in cash and cash equivalents	38.8	15.7
Cash and cash equivalents, January 1	35.4	39.7
Cash and cash equivalents, September 30	$ 73.8	$ 55.4

See Notes to Unaudited Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED EQUITY
(See Note 10 for Unit History and Detail of Changes in Limited Partners' Equity)
(Dollars in millions)

	Enterprise Products Partners L.P.				
	Limited Partners	General Partner	Accumulated Other Comprehensive Loss	Noncontrolling Interest	Total
Balance, December 31, 2008	$ 6,063.1	$ 123.6	$ (97.2)	$ 389.1	$ 6,478.6
Net income	504.6	120.2	--	42.5	667.3
Operating leases paid by EPCO, Inc.	0.5	--	--	--	0.5
Cash distributions to partners	(735.2)	(124.9)	--	--	(860.1)
Unit option reimbursements to EPCO, Inc.	(0.5)	--	--	--	(0.5)
Cash distributions paid to noncontrolling interest (see Note 10)	--	--	--	(47.9)	(47.9)
Net cash proceeds from issuance of common units	860.2	17.5	--	--	877.7
Cash proceeds from exercise of unit options	0.5	--	--	--	0.5
Cash contributions from noncontrolling interest (see Note 10)	--	--	--	137.4	137.4
Amortization of equity awards	13.5	0.2	--	--	13.7
Acquisition of treasury units	(1.8)	--	--	--	(1.8)
Foreign currency translation adjustment	--	--	1.7	--	1.7
Cash flow hedges	--	--	28.4	1.1	29.5
Other	--	--	--	(0.2)	(0.2)
Balance, September 30, 2009	$ 6,704.9	$ 136.6	$ (67.1)	$ 522.0	$ 7,296.4

	Enterprise Products Partners L.P.				
	Limited Partners	General Partner	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance, December 31, 2007	$ 5,992.9	$ 122.3	$ 19.1	$ 427.8	$ 6,562.1
Net income	620.5	105.5	--	29.3	755.3
Operating leases paid by EPCO, Inc.	1.5	--	--	--	1.5
Cash distributions to partners	(663.9)	(106.4)	--	--	(770.3)
Unit option reimbursements to EPCO, Inc.	(0.6)	--	--	--	(0.6)
Cash distributions paid to noncontrolling interest (see Note 10)	--	--	--	(39.2)	(39.2)
Net cash proceeds from issuance of common units	55.4	1.1	--	--	56.5
Cash proceeds from exercise of unit options	0.7	--	--	--	0.7
Amortization of equity awards	8.7	0.1	--	--	8.8
Interest acquired from noncontrolling interest	--	--	--	(7.6)	(7.6)
Acquisition of treasury units	(0.8)	--	--	--	(0.8)
Foreign currency translation adjustment	--	--	0.5	--	0.5
Change in funded status of pension and postretirement plans	--	--	(0.3)	--	(0.3)
Cash flow hedges	--	--	(134.3)	(0.6)	(134.9)
Balance, September 30, 2008	$ 6,014.4	$ 122.6	$ (115.0)	$ 409.7	$ 6,431.7

See Notes to Unaudited Condensed Consolidated Financial Statements.

Except per unit amounts, or as noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in millions of dollars.

Note 1. Partnership Organization and Basis of Presentation

Partnership Organization

Enterprise Products Partners L.P. is a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "EPD." Unless the context requires otherwise, references to "we," "us," "our" or "Enterprise Products Partners" are intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries.

We were formed in April 1998 to own and operate certain natural gas liquids ("NGLs") related businesses of EPCO, Inc. ("EPCO"). We conduct substantially all of our business through our wholly owned subsidiary, Enterprise Products Operating LLC ("EPO"). We are owned 98% by our limited partners and 2% by Enterprise Products GP, LLC (our general partner, referred to as "EPGP"). EPGP is owned 100% by Enterprise GP Holdings L.P. ("Enterprise GP Holdings"), a publicly traded limited partnership, the units of which are listed on the NYSE under the ticker symbol "EPE." The general partner of Enterprise GP Holdings is EPE Holdings, LLC ("EPE Holdings"), a wholly owned subsidiary of Dan Duncan LLC, all of the membership interests of which are owned by Dan L. Duncan. We, EPGP, Enterprise GP Holdings, EPE Holdings and Dan Duncan LLC are affiliates and under the common control of Dan L. Duncan, the Group Co-Chairman and controlling shareholder of EPCO.

References to "TEPPCO" and "TEPPCO GP" mean TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (which is the general partner of TEPPCO), respectively, prior to their mergers with our subsidiaries. On October 26, 2009, we completed the mergers with TEPPCO and TEPPCO GP (such related mergers referred to herein individually and together as the "TEPPCO Merger"). See Note 18 for additional information regarding the TEPPCO Merger.

References to "Energy Transfer Equity" mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries. References to "LE GP" mean LE GP, LLC, which is the general partner of Energy Transfer Equity. Enterprise GP Holdings owns a noncontrolling interest in both LE GP and Energy Transfer Equity. Enterprise GP Holdings accounts for its investments in LE GP and Energy Transfer Equity using the equity method of accounting.

References to "Employee Partnerships" mean EPE Unit L.P., EPE Unit II, L.P., EPE Unit III, L.P., Enterprise Unit L.P. and EPCO Unit L.P., collectively, all of which are privately held affiliates of EPCO.

For financial reporting purposes, we consolidate the financial statements of Duncan Energy Partners L.P. ("Duncan Energy Partners") with those of our own and reflect its operations in our business segments. We control Duncan Energy Partners through our ownership of its general partner, DEP Holdings, LLC ("DEP GP"). Also, due to common control of the entities by Dan L. Duncan, the initial consolidated balance sheet of Duncan Energy Partners reflects our historical carrying basis in each of the subsidiaries contributed to Duncan Energy Partners. Public ownership of Duncan Energy Partners' net assets and earnings are presented as a component of noncontrolling interest in our consolidated financial statements. The borrowings of Duncan Energy Partners are presented as part of our consolidated debt; however, neither Enterprise Products Partners L.P. nor EPO have any obligation for the payment of interest or repayment of borrowings incurred by Duncan Energy Partners.

Basis of Presentation

Effective January 1, 2009, we adopted new accounting guidance that has been codified under Accounting Standards Codification ("ASC") 810, Consolidation, which established accounting and reporting standards for noncontrolling interests that were previously identified as minority interest in our financial statements. The new guidance requires, among other things, that (i) noncontrolling interests be presented as a component of equity on our consolidated balance sheet (i.e., elimination of the "mezzanine" presentation previously used for minority interest); (ii) elimination of minority interest amounts as a deduction in deriving net income or loss and, as a result, that net income or loss be allocated between controlling and noncontrolling interests; and (iii) comprehensive income or loss be allocated between controlling and noncontrolling interest. Earnings per unit amounts are not affected by these changes. See Note 2 for additional information regarding the establishment of the ASC by the Financial Accounting Standards Board ("FASB"). See Note 10 for additional information regarding noncontrolling interest.

The new presentation and disclosure requirements pertaining to noncontrolling interests have been applied retroactively to the consolidated financial statements and notes included in this Quarterly Report. As a result, net income reported for the three and nine months ended September 30, 2008 in these financial statements is higher than that disclosed previously; however, the allocation of such net income results in our unitholders, general partner and noncontrolling interests (i.e., the former minority interest) receiving the same amounts as they did previously.

Our results of operations for the three and nine months ended September 30, 2009 are not necessarily indicative of results expected for the full year.

Essentially all of our assets, liabilities, revenues and expenses are recorded at EPO's level in our consolidated financial statements. Enterprise Products Partners L.P. acts as guarantor of certain of EPO's debt obligations. See Note 17 for condensed consolidated financial information of EPO.

In our opinion, the accompanying Unaudited Condensed Consolidated Financial Statements include all adjustments consisting of normal recurring accruals necessary for fair presentation. Although we believe the disclosures in these financial statements are adequate to make the information presented not misleading, certain information and footnote disclosures normally included in annual financial statements prepared in accordance with U.S. generally accepted accounting principles ("GAAP") have been condensed or omitted pursuant to the rules and regulations of the U.S. Securities and Exchange Commission ("SEC"). These Unaudited Condensed Consolidated Financial Statements and Notes thereto should be read in conjunction with the Audited Consolidated Financial Statements and Notes thereto included in our Current Report on Form 8-K dated July 8, 2009 (the "Recast Form 8-K"), which retroactively adjusted portions of our Annual Report on Form 10-K for the year ended December 31, 2008. The Recast Form 8-K reflects our adoption of the provisions under ASC 810 related to noncontrolling interests, our adoption of the provisions under ASC 260, Earnings Per Share, pertaining to the application of the two-class method to master limited partnerships in computing basic and diluted earnings per unit, and the resulting change in presentation and disclosure requirements.

Note 2. General Accounting Matters

Estimates

Preparing our financial statements in conformity with GAAP requires management to make estimates and assumptions that affect amounts presented in the financial statements (e.g. assets, liabilities, revenues and expenses) and disclosures about contingent assets and liabilities. Our actual results could differ from these estimates. On an ongoing basis, management reviews its estimates based on currently available information. Changes in facts and circumstances may result in revised estimates.

Fair Value Information

Cash and cash equivalents and restricted cash, accounts receivable, accounts payable and accrued expenses, and other current liabilities are carried at amounts which reasonably approximate their fair values due to their short-term nature. The estimated fair values of our fixed rate debt are based on quoted market prices for such debt or debt of similar terms and maturities. The carrying amounts of our variable rate debt obligations reasonably approximate their fair values due to their variable interest rates. See Note 4 for fair value information associated with our derivative instruments. The following table presents the estimated fair values of our financial instruments at the dates indicated:

Financial Instruments	September 30, 2009 Carrying Value	September 30, 2009 Fair Value	December 31, 2008 Carrying Value	December 31, 2008 Fair Value
Financial assets:				
Cash and cash equivalents and restricted cash	$ 176.6	$ 176.6	$ 239.2	$ 239.2
Accounts receivable	1,509.3	1,509.3	1,247.1	1,247.1
Financial liabilities:				
Accounts payable and accrued expenses	2,213.4	2,213.4	1,683.2	1,683.2
Other current liabilities	220.9	220.9	252.7	252.7
Fixed-rate debt (principal amount)	7,986.7	8,324.5	7,704.3	6,639.0
Variable-rate debt	1,158.3	1,158.3	1,341.8	1,341.8

Recent Accounting Developments

The following information summarizes recently issued accounting guidance that will or may affect our future financial statements.

Generally Accepted Accounting Principles. In June 2009, the FASB published ASC 105, Generally Accepted Accounting Principles, as the source of authoritative GAAP for U.S. companies. The ASC reorganized GAAP into a topical format and significantly changes the way users research accounting issues. For SEC registrants, the rules and interpretive releases of the SEC under federal securities laws are also sources of authoritative GAAP. References to specific GAAP in our consolidated financial statements now refer exclusively to the ASC. We adopted the new codification on September 30, 2009.

Fair Value Measurements. In April 2009, the FASB issued ASC 820, Fair Value Measurements and Disclosures, to clarify fair value accounting rules. This new accounting guidance establishes a process to determine whether a market is active and a transaction is consummated under distress. Companies should look at several factors and use professional judgment to ascertain if a formerly active market has become inactive. When estimating fair value, companies are required to place more weight on observable transactions in orderly markets. Our adoption of this new guidance on June 30, 2009 did not have any impact on our consolidated financial statements or related disclosures.

In August 2009, the FASB issued Accounting Standards Update 2009-05, Measuring Liabilities at Fair Value, to clarify how an entity should estimate the fair value of liabilities. If a quoted price in an active market for an identical liability is not available, a company must measure the fair value of the liability using one of several valuation techniques (e.g., quoted prices for similar liabilities or present value of cash flows). Our adoption of this new guidance on October 1, 2009 did not have any impact on our consolidated financial statements or related disclosures.

Financial Instruments. In April 2009, the FASB issued ASC 825, Financial Instruments, which requires companies to provide in each interim report both qualitative and quantitative information regarding fair value estimates for financial instruments not recorded on the balance sheet at fair value. Previously, this was only an annual requirement. Apart from adding the required fair value disclosures within this Note 2, our adoption of this new guidance on June 30, 2009 did not have a material impact on our consolidated financial statements or related disclosures.

Subsequent Events. In May 2009, the FASB issued ASC 855, Subsequent Events, which governs the accounting for, and disclosure of, events that occur after the balance sheet date but before financial statements are issued or are available to be issued. The date through which an entity has evaluated subsequent events is now a required disclosure. Our adoption of this guidance on June 30, 2009 did not have any impact on our consolidated financial statements.

Consolidation of Variable Interest Entities. In June 2009, the FASB amended consolidation guidance for variable interest entities ("VIEs") under ASC 810. VIEs are entities whose equity investors do not have sufficient equity capital at risk such that the entity cannot finance its own activities. When a business has a "controlling financial interest" in a VIE, the assets, liabilities and profit or loss of that entity must be consolidated. A business must also consolidate a VIE when that business has a "variable interest" that (i) provides the business with the power to direct the activities that most significantly impact the economic performance of the VIE and (ii) funds most of the entity's expected losses and/or receives most of the entity's anticipated residual returns. The amended guidance:

§ eliminates the scope exception for qualifying special-purpose entities;

§ amends certain guidance for determining whether an entity is a VIE;

§ expands the list of events that trigger reconsideration of whether an entity is a VIE;

§ requires a qualitative rather than a quantitative analysis to determine the primary beneficiary of a VIE;

§ requires continuous assessments of whether a company is the primary beneficiary of a VIE; and

§ requires enhanced disclosures about a company's involvement with a VIE.

The amended guidance is effective for us on January 1, 2010. At September 30, 2009, we did not have any VIEs based on prior guidance. We are in the process of evaluating the amended guidance; however, our adoption and implementation of this guidance is not expected to have an impact on our consolidated financial statements.

Restricted Cash

Restricted cash represents amounts held in connection with our commodity derivative instruments portfolio and related physical natural gas and NGL purchases. Additional cash may be restricted to maintain this portfolio as commodity prices fluctuate or deposit requirements change. At September 30, 2009 and December 31, 2008, our restricted cash amounts were $102.8 million and $203.8 million, respectively. See Note 4 for additional information regarding derivative instruments and hedging activities.

Subsequent Events

We have evaluated subsequent events through November 9, 2009, which is the date our Unaudited Condensed Consolidated Financial Statements and Notes are being issued.

Note 3. Accounting for Equity Awards

Certain key employees of EPCO participate in long-term incentive compensation plans managed by EPCO. The compensation expense we record related to equity awards is based on an allocation of the total cost of such incentive plans to EPCO. We record our pro rata share of such costs based on the percentage of time each employee spends on our consolidated business activities. Such awards were not material to our consolidated financial position, results of operations or cash flows for the periods presented. The amount of equity-based compensation allocable to our businesses was $5.5 million and $4.3 million for the three months ended September 30, 2009 and 2008, respectively. For the nine months ended September 30, 2009 and 2008, the amount of equity-based compensation allocable to our businesses was $13.7 million and $10.6 million, respectively.

EPCO 1998 Long-Term Incentive Plan

The EPCO 1998 Long-Term Incentive Plan ("EPCO 1998 Plan") provides for the issuance of up to 7,000,000 of our common units. After giving effect to the issuance or forfeiture of option awards and restricted unit awards through September 30, 2009, a total of 428,847 additional common units could be issued under the EPCO 1998 Plan.

Unit option awards. The following table presents option activity under the EPCO 1998 Plan for the periods indicated:

	Number of Units	Weighted-Average Strike Price (dollars/unit)	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (1)
Outstanding at December 31, 2008	2,168,500	$ 26.32		
Granted (2)	30,000	$ 20.08		
Exercised	(56,000)	$ 15.66		
Forfeited	(365,000)	$ 26.38		
Outstanding at September 30, 2009	1,777,500	$ 26.54	4.6	$ 3.0
Options exercisable at September 30, 2009	652,500	$ 23.71	4.7	$ 3.0

(1) Aggregate intrinsic value reflects fully vested unit options at September 30, 2009.
(2) Aggregate grant date fair value of these unit options issued during 2009 was $0.2 million based on the following assumptions: (i) a grant date market price of our common units of $20.08 per unit; (ii) expected life of options of 5.0 years; (iii) risk-free interest rate of 1.81%; (iv) expected distribution yield on our common units of 10%; and (v) expected unit price volatility on our common units of 72.76%.

The total intrinsic value of option awards exercised during the three months ended September 30, 2009 and 2008 was $0.3 million and $0.1 million, respectively. For each of the nine months ended September 30, 2009 and 2008, the total intrinsic value of option awards exercised was $0.6 million. At September 30, 2009, the estimated total unrecognized compensation cost related to nonvested unit option awards granted under the EPCO 1998 Plan was $1.1 million. We will recognize our share of these costs in accordance with the EPCO administrative services agreement (the "ASA") (see Note 12) over a weighted-average period of 1.8 years.

During the nine months ended September 30, 2009 and 2008, we received cash of $0.5 million and $0.7 million, respectively, from the exercise of option awards granted under the EPCO 1998 Plan. Conversely, our option-related reimbursements to EPCO during each of these periods were $0.5 million and $0.6 million, respectively.

Restricted unit awards. The following table summarizes information regarding our restricted unit awards under the EPCO 1998 Plan for the periods indicated:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Restricted units at December 31, 2008	2,080,600	
Granted (2)	1,016,950	$ 20.65
Vested	(244,300)	$ 26.66
Forfeited	(194,400)	$ 28.92
Restricted units at September 30, 2009	2,658,850	

(1) Determined by dividing the aggregate grant date fair value of awards by the number of awards issued. The weighted-average grant date fair value per unit for forfeited and vested awards is determined before an allowance for forfeitures.
(2) Net of forfeitures, aggregate grant date fair value of restricted unit awards issued during 2009 was $21.0 million based on grant date market prices of our common units ranging from $20.08 to $27.66 per unit. Estimated forfeiture rates ranged between 4.6% and 17%.

The total fair value of restricted unit awards that vested during the three and nine months ended September 30, 2009 was $6.2 million and $6.5 million, respectively. At September 30, 2009, the estimated total unrecognized compensation cost related to nonvested restricted unit awards granted under the EPCO 1998 Plan was $39.6 million. We expect to recognize our share of this cost over a weighted-average period of 2.5 years in accordance with the ASA.

Phantom unit awards and distribution equivalent rights. No phantom unit awards or distribution equivalent rights have been issued as of September 30, 2009 under the EPCO 1998 Plan.

Enterprise Products 2008 Long-Term Incentive Plan

The Enterprise Products 2008 Long-Term Incentive Plan ("EPD 2008 LTIP") provides for the issuance of up to 10,000,000 of our common units. After giving effect to the issuance or forfeiture of option awards through September 30, 2009, a total of 7,865,000 additional common units could be issued under the EPD 2008 LTIP.

Unit option awards. The following table presents unit option activity under the EPD 2008 LTIP for the periods indicated:

	Number of Units	Weighted-Average Strike Price (dollars/unit)	Weighted-Average Remaining Contractual Term (in years)
Outstanding at December 31, 2008	795,000	$ 30.93	
Granted (1)	1,430,000	$ 23.53	
Forfeited	(90,000)	$ 30.93	
Outstanding at September 30, 2009 (2)	2,135,000	$ 25.97	4.9

(1) Net of forfeitures, aggregate grant date fair value of these unit options issued during 2009 was $6.5 million based on the following assumptions: (i) a weighted-average grant date market price of our common units of $23.53 per unit; (ii) weighted-average expected life of options of 4.9 years; (iii) weighted-average risk-free interest rate of 2.14%; (iv) expected weighted-average distribution yield on our common units of 9.37%; (v) expected weighted-average unit price volatility on our common units of 57.11%. An estimated forfeiture rate of 17% was applied to awards granted during 2009.
(2) No unit options were exercisable as of September 30, 2009.

At September 30, 2009, the estimated total unrecognized compensation cost related to nonvested unit option awards granted under the EPD 2008 LTIP was $6.6 million. We expect to recognize our share of this cost over a weighted-average period of 3.4 years in accordance with the ASA.

Phantom unit awards. There were a total of 10,600 phantom units outstanding at September 30, 2009 under the EPD 2008 LTIP. These awards cliff vest in 2011 and 2012. At September 30, 2009 and December 31, 2008, we had accrued an immaterial liability for compensation related to these phantom unit awards.

Employee Partnerships

As of September 30, 2009, the estimated total unrecognized compensation cost related to the five Employee Partnerships was $37.7 million. We will recognize our share of these costs in accordance with the ASA over a weighted-average period of 4.2 years.

DEP GP Unit Appreciation Rights

At September 30, 2009 and December 31, 2008, we had a total of 90,000 outstanding unit appreciation rights ("UARs") granted to non-employee directors of DEP GP that cliff vest in 2012. If a director resigns prior to vesting, his UAR awards are forfeited. At September 30, 2009 and December 31, 2008, we had accrued an immaterial liability for compensation related to these UARs.

Note 4. Derivative Instruments, Hedging Activities and Fair Value Measurements

In the course of our normal business operations, we are exposed to certain risks, including changes in interest rates, commodity prices and, to a limited extent, foreign exchange rates. In order to manage risks associated with certain identifiable and anticipated transactions, we use derivative instruments. Derivatives are financial instruments whose fair value is determined by changes in a specified benchmark such as interest rates, commodity prices or currency values. Typical derivative instruments include futures, forward contracts, swaps and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities.

We are required to recognize derivative instruments at fair value as either assets or liabilities on the balance sheet. While all derivatives are required to be reported at fair value on the balance sheet, changes in fair value of the derivative instruments will be reported in different ways depending on the nature and effectiveness of the hedging activities to which they are related. After meeting specified conditions, a qualified derivative may be specifically designated as a total or partial hedge of:

§ Changes in the fair value of a recognized asset or liability, or an unrecognized firm commitment - In a fair value hedge, all gains and losses (of both the derivative instrument and the hedged item) are recognized in income during the period of change.

§ Variable cash flows of a forecasted transaction - In a cash flow hedge, the effective portion of the hedge is reported in other comprehensive income ("OCI") and is reclassified into earnings when the forecasted transaction affects earnings.

§ Foreign currency exposure, such as through an unrecognized firm commitment.

An effective hedge is one in which the change in fair value of a derivative instrument can be expected to offset 80% to 125% of changes in the fair value of a hedged item at inception and throughout the life of the hedging relationship. The effective portion of a hedge is the amount by which the derivative instrument exactly offsets the change in fair value of the hedged item during the reporting period. Conversely, ineffectiveness represents the change in the fair value of the derivative instrument that does not exactly offset the change in the fair value of the hedged item. Any ineffectiveness associated with a hedge is recognized in earnings immediately. Ineffectiveness can be caused by, among other things, changes in the timing of forecasted transactions or a mismatch of terms between the derivative instrument and the hedged item.

Interest Rate Derivative Instruments

We utilize interest rate swaps, treasury locks and similar derivative instruments to manage our exposure to changes in the interest rates of certain consolidated debt agreements. This strategy is a component in controlling our cost of capital associated with such borrowings.

The following table summarizes our interest rate derivative instruments outstanding at September 30, 2009, all of which were designated as hedging instruments under ASC 815-20, Hedging - General:

Hedged Transaction	Number and Type of Derivative Employed	Notional Amount	Period of Hedge	Rate Swap	Accounting Treatment
Enterprise Products Partners:					
Senior Notes C	1 fixed-to-floating swap	$100.0	1/04 to 2/13	6.4% to 2.8%	Fair value hedge
Senior Notes G	3 fixed-to-floating swaps	$300.0	10/04 to 10/14	5.6% to 2.6%	Fair value hedge
Senior Notes P	7 fixed-to-floating swaps	$400.0	6/09 to 8/12	4.6% to 2.7%	Fair value hedge
Duncan Energy Partners:					
Variable-interest rate borrowings	3 floating-to-fixed swaps	$175.0	9/07 to 9/10	0.3% to 4.6%	Cash flow hedge

The changes in fair value of the fair value interest rate swaps and the related hedged items were recorded on the balance sheet with the offset recorded as interest expense. This resulted in an increase of interest expense of $2.5 million and $3.1 million, respectively, for the three and nine months ended September 30, 2009.

At times, we may use treasury lock derivative instruments to hedge the underlying U.S. treasury rates related to forecasted issuances of debt. As cash flow hedges, gains or losses on these instruments are recorded in OCI and amortized to earnings using the effective interest method over the forecasted term of the underlying fixed-rate debt. In March 2008, we terminated treasury locks having a combined notional amount of $350.0 million. On April 1, 2008, we terminated additional treasury locks having a notional amount of $250.0 million. We recognized an aggregate loss of $20.7 million in OCI during the first quarter of 2008 related to these terminations. We recognized no losses in OCI during the second quarter of 2008 in connection with such terminations.

During the nine months ended September 30, 2009, we entered into three forward starting interest rate swaps to hedge the underlying benchmark interest payments related to the forecasted issuances of debt.

Hedged Transaction	Number and Type of Derivative Employed	Notional Amount	Period of Hedge	Average Rate Locked	Accounting Treatment
Enterprise Products Partners:					
Future debt offering	1 forward starting swap	$50.0	6/10 to 6/20	3.3%	Cash flow hedge
Future debt offering	2 forward starting swaps	$200.0	2/11 to 2/21	3.6%	Cash flow hedge

The fair market value of the forward starting swaps was $8.1 million at September 30, 2009. We entered into one additional forward starting swap for a notional amount of $50.0 million in October 2009 to hedge an anticipated 10-year note offering until February 2011.

For information regarding consolidated fair value amounts and gains and losses on interest rate derivative instruments and related hedged items, see "Tabular Presentation of Fair Value Amounts, and Gains and Losses on Derivative Instruments and Related Hedged Items" within this Note 4.

Commodity Derivative Instruments

The prices of natural gas, NGLs and certain petrochemical products are subject to fluctuations in response to changes in supply, demand, general market uncertainty and a variety of additional factors that are beyond our control. In order to manage the price risk associated with such products, we enter into commodity derivative instruments such as forwards, basis swaps and futures contracts. The following table summarizes our commodity derivative instruments outstanding at September 30, 2009:

	Volume (1)		Accounting
Derivative Purpose	**Current**	**Long-Term** (2)	**Treatment**
Derivatives designated as hedging instruments:			
Enterprise Products Partners:			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction ("PTR") (3)	16.6 Bcf	n/a	Cash flow hedge
Forecasted NGL sales	1.0 MMBbls	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchases of NGLs	0.1 MMBbls	n/a	Cash flow hedge
Forecasted sales of NGLs	n/a	0.1 MMBbls	Cash flow hedge
Forecasted sales of octane enhancement products	1.0 MMBbls	n/a	Cash flow hedge
Natural gas marketing:			
Natural gas storage inventory management activities	7.2 Bcf	n/a	Fair value hedge
Forecasted purchases of natural gas	n/a	3.0 Bcf	Cash flow hedge
Forecasted sales of natural gas	4.2 Bcf	0.9 Bcf	Cash flow hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products	2.7 MMBbls	0.1 MMBbls	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products	7.0 MMBbls	0.4 MMBbls	Cash flow hedge
Derivatives not designated as hedging instruments:			
Enterprise Products Partners:			
Natural gas risk management activities (4) (5)	313.3 Bcf	34.4 Bcf	Mark-to-market
Duncan Energy Partners:			
Natural gas risk management activities (5)	1.7 Bcf	n/a	Mark-to-market

(1) Volume for derivatives designated as hedging instruments reflects the total amount of volumes hedged whereas volume for derivatives not designated as hedging instruments reflects the absolute value of derivative notional volumes.
(2) The maximum term for derivatives included in the long-term column is December 2012.
(3) PTR represents the British thermal unit equivalent of the NGLs extracted from natural gas by a processing plant, and includes the natural gas used as plant fuel to extract those liquids, plant flare and other shortages. See the discussion below for the primary objective of this strategy.
(4) Volume includes approximately 61.8 billion cubic feet ("Bcf") of physical derivative instruments that are predominantly priced as an index plus a premium or minus a discount.
(5) Reflects the use of derivative instruments to manage risks associated with natural gas transportation, processing and storage assets.

The table above does not include additional hedges of forecasted NGL sales executed under contracts that have been designated as normal purchase and sale agreements. At September 30, 2009, the volume hedged under these contracts was 4.6 million barrels ("MMBbls").

Certain of our derivative instruments do not meet hedge accounting requirements; therefore, they are accounted for as economic hedges using mark-to-market accounting.

Our three predominant hedging strategies are hedging natural gas processing margins, hedging anticipated future sales margins on NGLs associated with physical volumes held in inventory and hedging the fair value of natural gas held in inventory.

The objective of our natural gas processing strategy is to hedge a level of gross margins associated with the NGL forward sales contracts (i.e., NGL sales revenues less actual costs for PTR and the gain or loss on the PTR hedge) by locking in the cost of natural gas used for PTR through the use of commodity derivative instruments. This program consists of:

§ the forward sale of a portion of our expected equity NGL production at fixed prices through December 2009, and

§ the purchase, using commodity derivative instruments, of the amount of natural gas expected to be consumed as PTR in the production of such equity NGL production.

At September 30, 2009, this program had hedged future estimated gross margins (before plant operating expenses) of $131.0 million on 5.0 MMBbls of forecasted NGL forward sales transactions extending through December 2009.

The objective of our NGL sales hedging program is to hedge future sales margins on physical NGL inventory by locking in the sales price through the use of commodity derivative instruments.

The objective of our natural gas inventory hedging program is to hedge the fair value of natural gas currently held in inventory by locking in the sales price of the inventory through the use of commodity derivative instruments.

For information regarding consolidated fair value amounts and gains and losses on commodity derivative instruments and related hedged items, see "Tabular Presentation of Fair Value Amounts, and Gains and Losses on Derivative Instruments and Related Hedged Items" within this Note 4.

Foreign Currency Derivative Instruments

We are exposed to foreign currency exchange risk in connection with our NGL and natural gas marketing activities in Canada. As a result, we could be adversely affected by fluctuations in currency rates between the U.S. dollar and Canadian dollar. In order to manage this risk, we may enter into foreign exchange purchase contracts to lock in the exchange rate. Prior to 2009, these derivative instruments were accounted for using mark-to-market accounting. Beginning with the first quarter of 2009, the long-term transactions (more than two months) are accounted for as cash flow hedges. Shorter term transactions are accounted for using mark-to-market accounting.

In addition, we were exposed to foreign currency exchange risk in connection with a term loan denominated in Japanese yen (see Note 9). We entered into this loan agreement in November 2008 and the loan matured in March 2009. The derivative instrument used to hedge this risk was accounted for as a cash flow hedge and settled upon repayment of the loan.

At September 30, 2009, we had foreign currency derivative instruments outstanding with a notional amount of $5.5 million Canadian. The fair market value of these instruments was an asset of $0.3 million at September 30, 2009.

For information regarding consolidated fair value amounts and gains and losses on foreign currency derivative instruments and related hedged items, see "Tabular Presentation of Fair Value Amounts, and Gains and Losses on Derivative Instruments and Related Hedged Items" within this Note 4.

Credit-Risk Related Contingent Features in Derivative Instruments

A limited number of our commodity derivative instruments include provisions related to credit ratings and/or adequate assurance clauses. A credit rating provision provides for a counterparty to demand immediate full or partial payment to cover a net liability position upon the loss of a stipulated credit rating. An adequate assurance clause provides for a counterparty to demand immediate full or partial payment to cover a net liability position should reasonable grounds for insecurity arise with respect to contractual performance by either party. At September 30, 2009, the aggregate fair value of our over-the-counter derivative instruments in a net liability position was $5.7 million, the total of which was subject to a credit rating contingent feature. If our credit ratings were downgraded to Ba2/BB, approximately $5.0 million would be payable as a margin deposit to the counterparties, and if our credit ratings were downgraded to Ba3/BB- or below, approximately $5.7 million would be payable as a margin deposit to the counterparties. Currently, no margin is required to be deposited. The potential for derivatives with contingent features to enter a net liability position may change in the future as positions and prices fluctuate.

Tabular Presentation of Fair Value Amounts, and Gains and Losses on Derivative Instruments and Related Hedged Items

The following table provides a balance sheet overview of our derivative assets and liabilities at the dates indicated:

	Asset Derivatives				Liability Derivatives			
	September 30, 2009		December 31, 2008		September 30, 2009		December 31, 2008	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments:								
Interest rate derivatives	Derivative assets	$ 23.2	Derivative assets	$ 7.8	Derivative liabilities	$ 6.0	Derivative liabilities	$ 5.9
Interest rate derivatives	Other assets	33.4	Other assets	39.0	Other liabilities	2.0	Other liabilities	3.9
Total interest rate derivatives		56.6		46.8		8.0		9.8
Commodity derivatives	Derivative assets	51.9	Derivative assets	150.5	Derivative liabilities	133.2	Derivative liabilities	253.5
Commodity derivatives	Other assets	0.2	Other assets	--	Other liabilities	2.1	Other liabilities	0.2
Total commodity derivatives (1)		52.1		150.5		135.3		253.7
Foreign currency derivatives (2)	Derivative assets	0.3	Derivative assets	9.3	Derivative liabilities	--	Derivative liabilities	--
Total derivatives designated as hedging instruments		$ 109.0		$ 206.6		$ 143.3		$ 263.5
Derivatives not designated as hedging instruments:								
Commodity derivatives	Derivative assets	$ 121.6	Derivative assets	$ 35.2	Derivative liabilities	$ 123.9	Derivative liabilities	$ 27.7
Commodity derivatives	Other assets	1.1	Other assets	--	Other liabilities	2.4	Other liabilities	--
Total commodity derivatives		122.7		35.2		126.3		27.7
Foreign currency derivatives	Derivative assets	--	Derivative assets	--	Derivative liabilities	--	Derivative liabilities	0.1
Total derivatives not designated as hedging instruments		$ 122.7		$ 35.2		$ 126.3		$ 27.8

(1) Represent commodity derivative instrument transactions that either have not settled or have settled and not been invoiced. Settled and invoiced transactions are reflected in either accounts receivable or accounts payable depending on the outcome of the transaction.
(2) Relates to the hedging of our exposure to fluctuations in the foreign currency exchange rate related to our Canadian NGL marketing subsidiary.

The following tables present the effect of our derivative instruments designated as fair value hedges on our Unaudited Condensed Statements of Consolidated Operations for the periods indicated:

Derivatives in Fair Value Hedging Relationships	Location	Gain/(Loss) Recognized in Income on Derivative			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2009	2008	2009	2008
Interest rate derivatives	Interest expense	$ 12.0	$ 4.2	$ (4.2)	$ (1.7)
Commodity derivatives	Revenue	0.6	--	(0.1)	--
Total		$ 12.6	$ 4.2	$ (4.3)	$ (1.7)

Derivatives in Fair Value Hedging Relationships	Location	Gain/(Loss) Recognized in Income on Hedged Item			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2009	2008	2009	2008
Interest rate derivatives	Interest expense	$ (14.5)	$ (4.2)	$ 1.1	$ 1.7
Commodity derivatives	Revenue	(0.5)	--	0.6	--
Total		$ (15.0)	$ (4.2)	$ 1.7	$ 1.7

The following tables present the effect of our derivative instruments designated as cash flow hedges on our Unaudited Condensed Statements of Consolidated Operations for the periods indicated:

Derivatives in Cash Flow Hedging Relationships	Change in Value Recognized in OCI on Derivative (Effective Portion)			
	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Interest rate derivatives	$ (8.0)	$ (1.1)	$ 7.1	$ (22.9)
Commodity derivatives – Revenue	(21.3)	(25.3)	44.5	(30.2)
Commodity derivatives – Operating costs and expenses	13.0	(218.7)	(191.4)	(93.9)
Foreign currency derivatives	0.2	--	(10.3)	(1.3)
Total	$ (16.1)	$ (245.1)	$ (150.1)	$ (148.3)

Derivatives in Cash Flow Hedging Relationships	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI to Income (Effective Portion)			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2009	2008	2009	2008
Interest rate derivatives	Interest expense	$ (1.3)	$ --	$ (3.3)	$ 2.4
Commodity derivatives	Revenue	(12.5)	(17.2)	7.2	(23.3)
Commodity derivatives	Operating costs and expenses	(65.3)	(11.3)	(183.5)	7.5
Total		$ (79.1)	$ (28.5)	$ (179.6)	$ (13.4)

Derivatives in Cash Flow Hedging Relationships	Location of Gain/(Loss) Recognized in Income on Ineffective Portion of Derivative	Amount of Gain/(Loss) Recognized in Income on Ineffective Portion of Derivative			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2009	2008	2009	2008
Commodity derivatives	Revenue	$ 0.8	$ --	$ 0.1	$ --
Commodity derivatives	Operating costs and expenses	(1.0)	(5.7)	(2.3)	(2.9)
Total		$ (0.2)	$ (5.7)	$ (2.2)	$ (2.9)

Over the next twelve months, we expect to reclassify $5.3 million of accumulated other comprehensive loss (“AOCI”) attributable to interest rate derivative instruments to earnings as an increase to interest expense. Likewise, we expect to reclassify $81.3 million of AOCI attributable to commodity derivative instruments to earnings, $32.1 million as an increase in operating costs and expenses and $49.2 million as a reduction in revenues.

The following table presents the effect of our derivative instruments not designated as hedging instruments on our Unaudited Condensed Statements of Consolidated Operations for the periods indicated:

Derivatives Not Designated as Hedging Instruments	Location	Gain/(Loss) Recognized in Income on Derivative			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2009	2008	2009	2008
Commodity derivatives (1)	Revenue	$ (6.1)	$ 38.1	$ 25.4	$ 35.2
Commodity derivatives	Operating costs and expenses	--	1.9	--	(7.1)
Foreign currency derivatives	Other income	--	--	(0.1)	--
Total		$ (6.1)	$ 40.0	$ 25.3	$ 28.1

(1) Amounts for the three and nine months ended September 30, 2009 include $0.9 million and $3.8 million of gains on derivatives excluded from the assessment of hedge effectiveness under fair value hedging relationships, respectively.

Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at a specified measurement date. Our fair value estimates are based on either (i) actual market data or (ii) assumptions that other market participants would use in pricing an asset or liability, including estimates of risk. Recognized valuation techniques employ inputs such as product prices, operating costs, discount factors and business growth rates. These inputs may be either readily observable, corroborated by market data or generally unobservable. In developing our estimates of fair value, we endeavor to utilize the best information available and apply market-based data to the extent possible. Accordingly, we utilize valuation techniques (such as the market approach) that maximize the use of observable inputs and minimize the use of unobservable inputs.

A three-tier hierarchy has been established that classifies fair value amounts recognized or disclosed in the financial statements based on the observability of inputs used to estimate such fair values. The hierarchy considers fair value amounts based on observable inputs (Levels 1 and 2) to be more reliable and predictable than those based primarily on unobservable inputs (Level 3). At each balance sheet reporting date, we categorize our financial assets and liabilities using this hierarchy. The characteristics of fair value amounts classified within each level of the hierarchy are described as follows:

§ Level 1 fair values are based on quoted prices, which are available in active markets for identical assets or liabilities as of the measurement date. Active markets are defined as those in which transactions for identical assets or liabilities occur with sufficient frequency so as to provide pricing information on an ongoing basis (e.g., the New York Mercantile Exchange). Our Level 1 fair values primarily consist of financial assets and liabilities such as exchange-traded commodity financial instruments.

§ Level 2 fair values are based on pricing inputs other than quoted prices in active markets (as reflected in Level 1 fair values) and are either directly or indirectly observable as of the measurement date. Level 2 fair values include instruments that are valued using financial models or other appropriate valuation methodologies. Such financial models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, the time value of money, volatility factors, current market and contractual prices for the underlying instruments and other relevant economic measures. Substantially all of these assumptions are (i) observable in the marketplace throughout the full term of the instrument, (ii) can be derived from observable data or (iii) are validated by inputs other than quoted prices (e.g., interest rate and yield curves at commonly quoted intervals). Our Level 2 fair values primarily consist of commodity financial instruments such as forwards, swaps and other instruments transacted on an exchange or over the counter. The fair values of these derivatives are based on observable price quotes for similar products and locations. The value of our interest rate derivatives are valued by using appropriate financial models with the implied forward London Interbank Offered Rate yield curve for the same period as the future interest swap settlements.

§ Level 3 fair values are based on unobservable inputs. Unobservable inputs are used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Unobservable inputs reflect the reporting entity's own ideas about the assumptions that market participants would use in pricing an asset or liability (including assumptions about risk). Unobservable inputs are based on the best information available in the circumstances, which might include the reporting entity's internally developed data. The reporting entity must not ignore information about market participant assumptions that is reasonably available without undue cost and effort. Level 3 inputs are typically used in connection with internally developed valuation methodologies where management makes its best estimate of an instrument's fair value. Our Level 3 fair values largely consist of ethane and normal butane-based contracts with a range of two to twelve months in term. We rely on broker quotes for these products.

The following table sets forth, by level within the fair value hierarchy, our financial assets and liabilities measured on a recurring basis at September 30, 2009. These financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value assets and liabilities and their placement within the fair value hierarchy levels.

	Level 1	Level 2	Level 3	Total
Financial assets:				
Interest rate derivative instruments	$ --	$ 56.6	$ --	$ 56.6
Commodity derivative instruments	10.9	151.8	12.1	174.8
Foreign currency derivative instruments	--	0.3	--	0.3
Total	$ 10.9	$ 208.7	$ 12.1	$ 231.7
Financial liabilities:				
Interest rate derivative instruments	$ --	$ 8.0	$ --	$ 8.0
Commodity derivative instruments	36.7	211.1	13.8	261.6
Total	$ 36.7	$ 219.1	$ 13.8	$ 269.6

The following table sets forth a reconciliation of changes in the fair value of our Level 3 financial assets and liabilities for the periods presented:

	For the Nine Months Ended September 30,	
	2009	2008
Balance, January 1	$ 32.6	$ (4.6)
Total gains (losses) included in:		
Net income (1)	12.5	(2.3)
Other comprehensive income (loss)	1.5	2.4
Purchases, issuances, settlements	(12.5)	1.9
Balance, March 31	34.1	(2.6)
Total gains (losses) included in:		
Net income (1)	7.7	0.3
Other comprehensive income (loss)	(23.1)	(2.4)
Purchases, issuances, settlements	(7.7)	0.1
Transfers out of Level 3	(0.2)	--
Balance, June 30	10.8	(4.6)
Total gains (losses) included in:		
Net income (1)	6.5	(2.2)
Other comprehensive income (loss)	(10.2)	23.1
Purchases, issuances, settlements	(6.5)	2.2
Transfers out of Level 3	(2.3)	--
Balance, September 30	$ (1.7)	$ 18.5

(1) There were $4.8 million and $5.0 million of unrealized losses included in these amounts for the three and nine months ended September 30, 2009, respectively. For the three and nine months ended September 30, 2008, there were no unrealized gains or losses included in these amounts.

Nonfinancial Assets and Liabilities

Certain nonfinancial assets and liabilities are measured at fair value on a nonrecurring basis and are subject to fair value adjustments in certain circumstances (for example, when there is evidence of impairment). There were no material fair value adjustments for such assets or liabilities reflected in our consolidated financial statements for the three and nine months ended September 30, 2009.

Note 5. Inventories

Our inventory amounts were as follows at the dates indicated:

	September 30, 2009	December 31, 2008
Working inventory (1)	$ 508.1	$ 200.4
Forward sales inventory (2)	639.4	162.4
Total inventory	$ 1,147.5	$ 362.8

(1) Working inventory is comprised of inventories of natural gas, NGLs and certain petrochemical products that are either available-for-sale or used in providing services.
(2) Forward sales inventory consists of identified NGL and natural gas volumes dedicated to the fulfillment of forward sales contracts. As a result of energy market conditions, we significantly increased our physical inventory purchases and related forward physical sales commitments during 2009. In general, the significant increase in volumes dedicated to forward physical sales contracts improves the overall utilization and profitability of our fee-based assets.

Our inventory values reflect payments for product purchases, freight charges associated with such purchase volumes, terminal and storage fees, vessel inspection costs, demurrage charges and other related costs. Inventories are valued at the lower of average cost or market.

Operating costs and expenses, as presented on our Unaudited Condensed Statements of Consolidated Operations, include cost of sales amounts related to the sale of inventories. Our costs of sales amounts were $3.72 billion and $5.47 billion for the three months ended September 30, 2009 and 2008, respectively. For the nine months ended September 30, 2009 and 2008, our costs of sales amounts were $9.05 billion and $15.88 billion, respectively. The decrease in cost of sales period-to-period is primarily due to lower energy commodity prices associated with our marketing activities.

Due to fluctuating commodity prices, we recognize lower of average cost or market ("LCM") adjustments when the carrying value of our available-for-sale inventories exceed their net realizable value. These non-cash charges are a component of cost of sales in the period they are recognized, and reflected in operating costs and expenses as presented on our Unaudited Condensed Statements of Consolidated Operations. LCM adjustments may be mitigated or offset through the use of commodity hedging instruments to the extent such instruments affect net realizable value. See Note 4 for a description of our commodity hedging activities. For the three months ended September 30, 2009 and 2008, we recognized LCM adjustments of $0.4 million and $36.5 million, respectively. We recognized LCM adjustments of $6.4 million and $41.3 million for the nine months ended September 30, 2009 and 2008, respectively.

Note 6. Property, Plant and Equipment

Our property, plant and equipment values and accumulated depreciation balances were as follows at the dates indicated:

	Estimated Useful Life in Years	September 30, 2009	December 31, 2008
Plants and pipelines (1)	3-45 (5)	$ 13,927.2	$ 12,296.3
Underground and other storage facilities (2)	5-35 (6)	944.2	900.7
Platforms and facilities (3)	20-31	637.6	634.8
Transportation equipment (4)	3-10	41.5	38.7
Land		59.4	54.6
Construction in progress		802.8	1,604.7
Total		16,412.7	15,529.8
Less accumulated depreciation		2,751.1	2,375.0
Property, plant and equipment, net		$ 13,661.6	$ 13,154.8

(1) Plants and pipelines include processing plants; NGL, petrochemical, crude oil and natural gas pipelines; terminal loading and unloading facilities; office furniture and equipment; buildings; laboratory and shop equipment; and related assets.
(2) Underground and other storage facilities include underground product storage caverns; storage tanks; water wells; and related assets.
(3) Platforms and facilities include offshore platforms and related facilities and other associated assets.
(4) Transportation equipment includes vehicles and similar assets used in our operations.
(5) In general, the estimated useful lives of major components of this category are as follows: processing plants, 20-35 years; pipelines, 18-45 years (with some equipment at 5 years); terminal facilities, 10-35 years; office furniture and equipment, 3-20 years; buildings, 20-35 years; and laboratory and shop equipment, 5-35 years.
(6) In general, the estimated useful lives of major components of this category are as follows: underground storage facilities, 20-35 years (with some components at 5 years); storage tanks, 10-35 years; and water wells, 25-35 years (with some components at 5 years).

The following table summarizes our depreciation expense and capitalized interest amounts for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Depreciation expense (1)	$ 138.0	$ 115.5	$ 393.5	$ 339.3
Capitalized interest (2)	6.6	17.3	24.3	53.0

(1) Depreciation expense is a component of costs and expenses as presented in our Unaudited Condensed Statements of Consolidated Operations.
(2) Capitalized interest increases the carrying value of the associated asset and reduces interest expense during the period it is recorded.

In May 2009, we acquired certain rail and truck terminal facilities located in Mont Belvieu, Texas from Martin Midstream Partners L.P. ("Martin"). Cash consideration paid for this business combination was $23.7 million, all of which was recorded as additions to property, plant and equipment.

On a pro forma consolidated basis, our revenues, costs and expenses, operating income, net income and earnings per unit amounts would not have differed materially from those we actually reported for the three and nine months ended September 30, 2009 and 2008 due to the immaterial nature of our 2009 business combination transaction.

Asset Retirement Obligations

Asset retirement obligations ("AROs") are legal obligations associated with the retirement of certain tangible long-lived assets that result from acquisitions, construction, development and/or normal operations. The following table presents information regarding our AROs since December 31, 2008.

ARO liability balance, December 31, 2008	$ 37.7
Liabilities incurred	0.4
Liabilities settled	(13.6)
Revisions in estimated cash flows	23.6
Accretion expense	2.0
ARO liability balance, September 30, 2009	$ 50.1

The increase in our ARO liability balance during 2009 primarily reflects revised estimates of the cost to comply with regulatory abandonment obligations associated with our facilities offshore in the Gulf of Mexico. We incurred $13.6 million of costs through September 30, 2009 as a result of ARO settlement activities associated with certain pipeline laterals and a platform located in the Gulf of Mexico.

Property, plant and equipment at September 30, 2009 and December 31, 2008 includes $25.7 million and $9.9 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset. Based on information currently available, we estimate that accretion expense will approximate $0.9 million for the fourth quarter of 2009, $3.5 million for 2010, $3.4 million for 2011, $3.7 million for 2012 and $4.0 million for 2013.

Note 7. Investments in Unconsolidated Affiliates

We own interests in a number of related businesses that are accounted for using the equity method of accounting. Our investments in unconsolidated affiliates are grouped according to the business segment to which they relate. See Note 11 for a general discussion of our business segments. The following table shows our investments in unconsolidated affiliates at the dates indicated:

	Ownership Percentage at September 30, 2009	September 30, 2009	December 31, 2008
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C.	13.1%	$ 33.1	$ 37.7
K/D/S Promix, L.L.C. ("Promix")	50%	47.8	46.4
Baton Rouge Fractionators LLC	32.2%	23.6	24.1
Skelly-Belvieu Pipeline Company, L.L.C. ("Skelly-Belvieu")	49%	37.4	36.0
Onshore Natural Gas Pipelines & Services:			
Jonah Gas Gathering Company ("Jonah")	19.4%	250.1	258.1
Evangeline (1)	49.5%	5.4	4.5
White River Hub, LLC	50%	27.0	21.4
Offshore Pipelines & Services:			
Poseidon Oil Pipeline, L.L.C. ("Poseidon")	36%	61.3	60.2
Cameron Highway Oil Pipeline Company ("Cameron Highway")	50%	243.2	250.8
Deepwater Gateway, L.L.C.	50%	102.8	104.8
Neptune Pipeline Company, L.L.C. ("Neptune")	25.7%	54.4	52.7
Nemo Gathering Company, LLC	33.9%	--	0.4
Texas Offshore Port System ("TOPS") (2)	--	--	35.9
Petrochemical Services:			
Baton Rouge Propylene Concentrator, LLC	30%	11.4	12.6
La Porte (3)	50%	3.5	3.9
Total		$ 901.0	$ 949.5

(1) Refers to our ownership interests in Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp., collectively.
(2) In April 2009, we elected to dissociate from this partnership and forfeit our investment (see discussion below).
(3) Refers to our ownership interests in La Porte Pipeline Company, L.P. and La Porte GP, LLC, collectively.

Our investments in Promix, La Porte, Neptune, Poseidon, Cameron Highway, Jonah and Skelly-Belvieu include excess cost amounts totaling $54.8 million and $56.6 million at September 30, 2009 and December 31, 2008, respectively, all of which are attributable to the fair value of the underlying tangible assets of these entities exceeding their book carrying values at the time of our acquisition of interests in these entities. To the extent that we attribute all or a portion of an excess cost amount to higher fair values, we amortize such excess cost as a reduction in equity earnings in a manner similar to depreciation. To the extent we attribute an excess cost amount to goodwill, we do not amortize this amount, but it is subject to evaluation for impairment. Amortization of excess cost amounts was $0.6 million and $0.5 million for the three months ended September 30, 2009 and 2008, respectively. For the nine months ended September 30, 2009 and 2008, amortization of such amounts was $1.8 million and $1.5 million, respectively.

The following table presents our equity in income (loss) of unconsolidated affiliates by business segment for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
NGL Pipelines & Services	$ 4.0	$ 3.0	$ 7.5	$ 2.3
Onshore Natural Gas Pipelines & Services	7.4	5.6	21.7	16.9
Offshore Pipelines & Services	10.6	6.0	(12.1)	27.9
Petrochemical Services	0.5	0.3	1.2	1.0
Total	$ 22.5	$ 14.9	$ 18.3	$ 48.1

Exit from TOPS Partnership

In August 2008, a wholly owned subsidiary of ours, together with a subsidiary of TEPPCO and Oiltanking Holding Americas, Inc. ("Oiltanking"), formed the TOPS partnership. Effective April 16, 2009, our wholly owned subsidiary dissociated from TOPS. As a result, equity earnings for the nine months ended September 30, 2009 reflects a non-cash charge of $34.2 million. This loss, which is classified within our Offshore Pipelines & Services business segment, represents our cumulative investment in TOPS through the date of dissociation and reflects our capital contributions to TOPS for construction in progress amounts. The wholly owned subsidiary of TEPPCO that was a partner in TOPS also dissociated from the partnership effective April 16, 2009 and recorded a $34.2 million non-cash charge. See Note 14 for litigation matters associated with TOPS.

Summarized Financial Information of Unconsolidated Affiliates

The following tables present unaudited income statement data for our current unconsolidated affiliates, aggregated by business segment, for the periods indicated (on a 100% basis):

	Summarized Income Statement Information for the Three Months Ended					
	September 30, 2009			September 30, 2008		
	Revenues	Operating Income	Net Income	Revenues	Operating Income	Net Income
NGL Pipelines & Services	$ 60.0	$ 10.9	$ 11.2	$ 75.1	$ 9.7	$ 6.7
Onshore Natural Gas Pipelines & Services	108.6	34.2	34.3	188.9	29.0	27.9
Offshore Pipelines & Services	43.2	24.7	24.0	31.9	12.9	12.0
Petrochemical Services	5.1	2.0	2.0	5.6	1.1	1.1

	Summarized Income Statement Information for the Nine Months Ended					
	September 30, 2009			September 30, 2008		
	Revenues	Operating Income	Net Income	Revenues	Operating Income	Net Income
NGL Pipelines & Services	$ 161.7	$ 23.7	$ 24.2	$ 217.8	$ 17.7	$ 15.0
Onshore Natural Gas Pipelines & Services	311.8	100.7	100.8	492.5	88.7	85.3
Offshore Pipelines & Services	106.4	39.2	37.7	115.0	62.4	57.2
Petrochemical Services	14.9	5.1	5.1	16.6	3.9	3.9

Note 8. Intangible Assets and Goodwill

Identifiable Intangible Assets

The following table summarizes our intangible assets by segment at the dates indicated:

	September 30, 2009			December 31, 2008		
	Gross Value	Accum. Amort.	Carrying Value	Gross Value	Accum. Amort.	Carrying Value
NGL Pipelines & Services:						
Customer relationship intangibles	$ 237.4	$ (82.2)	$ 155.2	$ 237.4	$ (68.7)	$ 168.7
Contract-based intangibles	299.9	(131.6)	168.3	299.7	(117.4)	182.3
Subtotal	537.3	(213.8)	323.5	537.1	(186.1)	351.0
Onshore Natural Gas Pipelines & Services:						
Customer relationship intangibles	372.0	(119.1)	252.9	372.0	(103.2)	268.8
Contract-based intangibles	101.3	(43.1)	58.2	101.3	(36.6)	64.7
Subtotal	473.3	(162.2)	311.1	473.3	(139.8)	333.5
Offshore Pipelines & Services:						
Customer relationship intangibles	205.8	(101.8)	104.0	205.8	(90.7)	115.1
Contract-based intangibles	1.2	(0.2)	1.0	1.2	(0.1)	1.1
Subtotal	207.0	(102.0)	105.0	207.0	(90.8)	116.2
Petrochemical Services:						
Customer relationship intangibles	53.0	(11.6)	41.4	53.0	(10.5)	42.5
Contract-based intangibles	14.9	(2.9)	12.0	14.9	(2.7)	12.2
Subtotal	67.9	(14.5)	53.4	67.9	(13.2)	54.7
Total	$ 1,285.5	$ (492.5)	$ 793.0	$ 1,285.3	$ (429.9)	$ 855.4

The following table presents the amortization expense of our intangible assets by business segment for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
NGL Pipelines & Services	$ 9.1	$ 9.7	$ 27.7	$ 29.6
Onshore Natural Gas Pipelines & Services	7.4	7.5	22.4	22.9
Offshore Pipelines & Services	3.6	4.1	11.2	12.8
Petrochemical Services	0.4	0.5	1.3	1.5
Total	$ 20.5	$ 21.8	$ 62.6	$ 66.8

Based on information currently available, we estimate that amortization expense will approximate $20.2 million for the fourth quarter of 2009, $77.8 million for 2010, $72.0 million for 2011, $62.3 million for 2012 and $56.4 million for 2013.

Goodwill

The following table summarizes our goodwill amounts by business segment at the dates indicated:

	September 30, 2009	December 31, 2008
NGL Pipelines & Services	$ 269.0	$ 269.0
Onshore Natural Gas Pipelines & Services	282.1	282.1
Offshore Pipelines & Services	82.1	82.1
Petrochemical Services	73.7	73.7
Total	$ 706.9	$ 706.9

Note 9. Debt Obligations

Our consolidated debt obligations consisted of the following at the dates indicated:

	September 30, 2009	December 31, 2008
EPO senior debt obligations:		
Multi-Year Revolving Credit Facility, variable rate, due November 2012	$ 638.0	$ 800.0
Pascagoula MBFC Loan, 8.70% fixed-rate, due March 2010 (1)	54.0	54.0
Petal GO Zone Bonds, variable rate, due August 2037	57.5	57.5
Yen Term Loan, 4.93% fixed-rate, due March 2009 (2)	--	217.6
Senior Notes B, 7.50% fixed-rate, due February 2011	450.0	450.0
Senior Notes C, 6.375% fixed-rate, due February 2013	350.0	350.0
Senior Notes D, 6.875% fixed-rate, due March 2033	500.0	500.0
Senior Notes F, 4.625% fixed-rate, due October 2009 (1)	500.0	500.0
Senior Notes G, 5.60% fixed-rate, due October 2014	650.0	650.0
Senior Notes H, 6.65% fixed-rate, due October 2034	350.0	350.0
Senior Notes I, 5.00% fixed-rate, due March 2015	250.0	250.0
Senior Notes J, 5.75% fixed-rate, due March 2035	250.0	250.0
Senior Notes K, 4.950% fixed-rate, due June 2010 (1)	500.0	500.0
Senior Notes L, 6.30% fixed-rate, due September 2017	800.0	800.0
Senior Notes M, 5.65% fixed-rate, due April 2013	400.0	400.0
Senior Notes N, 6.50% fixed-rate, due January 2019	700.0	700.0
Senior Notes O, 9.75% fixed-rate, due January 2014	500.0	500.0
Senior Notes P, 4.60% fixed-rate, due August 2012	500.0	--
Duncan Energy Partners' debt obligations:		
DEP Revolving Credit Facility, variable rate, due February 2011	180.5	202.0
DEP Term Loan, variable rate, due December 2011	282.3	282.3
Total principal amount of senior debt obligations	7,912.3	7,813.4
EPO Junior Subordinated Notes A, fixed/variable rate, due August 2066	550.0	550.0
EPO Junior Subordinated Notes B, fixed/variable rate, due January 2068	682.7	682.7
Total principal amount of senior and junior debt obligations	9,145.0	9,046.1
Other, non-principal amounts:		
Change in fair value of debt-related derivative instruments	47.6	51.9
Unamortized discounts, net of premiums	(7.3)	(7.3)
Unamortized deferred net gains related to terminated interest rate swaps	13.0	17.7
Total other, non-principal amounts	53.3	62.3
Total long-term debt	$ 9,198.3	$ 9,108.4
Letters of credit outstanding	$ 109.3	$ 1.0

(1) In accordance with ASC 470, Debt, long-term and current maturities of debt reflect the classification of such obligations at September 30, 2009 after taking into consideration EPO's (i) $1.1 billion issuance of Senior Notes in October 2009 and (ii) ability to use available borrowing capacity under its Multi-Year Revolving Credit Facility.
(2) The Yen Term Loan matured on March 30, 2009.

Parent-Subsidiary Guarantor Relationships

Enterprise Products Partners L.P. acts as guarantor of the consolidated debt obligations of EPO with the exception of the DEP Revolving Credit Facility and the DEP Term Loan. If EPO were to default on any of its guaranteed debt, Enterprise Products Partners L.P. would be responsible for full repayment of that obligation.

Letters of Credit

At September 30, 2009, EPO had outstanding a $50.0 million letter of credit relating to its commodity derivative instruments and a $58.3 million letter of credit related to its Petal GO Zone Bonds. These letter of credit facilities do not reduce the amount available for borrowing under EPO's credit facilities. In addition, at September 30, 2009, Duncan Energy Partners had an outstanding letter of credit in the amount of $1.0 million which reduces the amount available for borrowing under its credit facility.

EPO's Debt Obligations

Apart from that discussed below, there have been no significant changes in the terms of our debt obligations since those reported in our Recast Form 8-K.

$200.0 Million Term Loan. In April 2009, EPO entered into a $200.0 Million Term Loan, which was subsequently repaid and terminated in June 2009 using funds from the issuance of Senior Notes P (see below).

Senior Notes P. In June 2009, EPO issued $500.0 million in principal amount of 3-year senior unsecured notes ("Senior Notes P"). Senior Notes P were issued at 99.95% of their principal amount, have a fixed interest rate of 4.60% and mature on August 1, 2012. Net proceeds from the issuance of Senior Notes P were used (i) to repay amounts borrowed under the $200 Million Term Loan, (ii) to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and (iii) for general partnership purposes.

Senior Notes P rank equal with EPO's existing and future unsecured and unsubordinated indebtedness. They are senior to any existing and future subordinated indebtedness of EPO. Senior Notes P are subject to make-whole redemption rights and were issued under indentures containing certain covenants, which generally restrict EPO's ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions.

364-Day Revolving Credit Facility. In November 2008, EPO executed a standby 364-Day Revolving Credit Agreement (the "364-Day Facility") that had a borrowing capacity of $375.0 million. The 364-Day Facility was terminated in June 2009 under its terms as a result of the issuance of Senior Notes P. No amounts were borrowed under this standby facility through its termination date.

Exchange Offers for TEPPCO Notes. In September 2009, EPO commenced offers to exchange all outstanding notes issued by TEPPCO for a corresponding series of new notes to be issued by EPO and guaranteed by Enterprise Products Partners L.P. The aggregate principal amount of the TEPPCO notes subject to the exchange was $2 billion. The exchange offer was completed on October 27, 2009, resulting in the exchange of approximately $1.95 billion of new EPO notes for existing TEPPCO notes. See Note 18 for additional information regarding this exchange offer.

Senior Notes Q and R. In October 2009, EPO issued $500.0 million in principal amount of 10-year senior unsecured notes ("Senior Notes Q") and $600.0 million in principal amount of 30-year senior unsecured notes ("Senior Notes R"). EPO used a portion of the net proceeds it received from the issuance of Senior Notes Q and R to repay its $500.0 million in principal amount unsecured notes ("Senior Notes F") that matured in October 2009. See Note 18 for additional information regarding these debt issuances.

Dixie Revolving Credit Facility

The Dixie Revolving Credit Facility was terminated in January 2009. As of December 31, 2008, there were no debt obligations outstanding under this facility.

Covenants

We were in compliance with the covenants of our consolidated debt agreements at September 30, 2009.

Information Regarding Variable Interest Rates Paid

The following table shows the weighted-average interest rate paid on our consolidated variable-rate debt obligations during the nine months ended September 30, 2009.

	Weighted-Average Interest Rate Paid
EPO's Multi-Year Revolving Credit Facility	0.97%
DEP Revolving Credit Facility	1.64%
DEP Term Loan	1.20%
Petal GO Zone Bonds	0.76%

Consolidated Debt Maturity Table

The following table presents the scheduled contractual maturities of principal amounts of our debt obligations for the next five years and in total thereafter.

2009 (1)	$	500.0
2010 (1)		554.0
2011		912.8
2012		1,138.0
2013		750.0
Thereafter		5,290.2
Total scheduled principal payments	$	9,145.0

(1) Long-term and current maturities of debt reflect the classification of such obligations on our Unaudited Condensed Consolidated Balance Sheet at September 30, 2009 after taking into consideration EPO's (i) $1.1 billion issuance of Senior Notes in October 2009 and (ii) ability to use available borrowing capacity under its Multi-Year Revolving Credit Facility.

Debt Obligations of Unconsolidated Affiliates

We have two unconsolidated affiliates with long-term debt obligations. The following table shows (i) our ownership interest in each entity at September 30, 2009, (ii) total debt of each unconsolidated affiliate at September 30, 2009 (on a 100% basis to the affiliate) and (iii) the corresponding scheduled maturities of such debt.

	Our Ownership Interest	Total	Scheduled Maturities of Debt 2009	2010	2011
Poseidon	36%	$ 92.0	$ --	$ --	$ 92.0
Evangeline	49.5%	15.7	5.0	3.2	7.5
Total		$ 107.7	$ 5.0	$ 3.2	$ 99.5

The credit agreements of our unconsolidated affiliates contain various affirmative and negative covenants, including financial covenants. These businesses were in compliance with such covenants at September 30, 2009. The credit agreements of our unconsolidated affiliates also restrict their ability to pay cash dividends if a default or an event of default (as defined in each credit agreement) has occurred and is continuing at the time such dividend is scheduled to be paid.

There have been no significant changes in the terms of the debt obligations of our unconsolidated affiliates since those reported in our Recast Form 8-K.

Note 10. Equity and Distributions

Our common units represent limited partner interests, which give the holders thereof the right to participate in distributions and to exercise the other rights or privileges available to them under our Fifth Amended and Restated Agreement of Limited Partnership (together with all amendments thereto, the "Partnership Agreement"). We are managed by our general partner, EPGP.

Equity Offerings and Registration Statements

We have a universal shelf registration statement on file with the SEC that allows us to issue an unlimited amount of debt and equity securities for general partnership purposes. In January 2009, we issued 10,590,000 common units (including an over-allotment of 990,000 common units) to the public at an offering price of $22.20 per unit under this registration statement. We used the net proceeds of $225.6 million from the January 2009 equity offering to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes. In June 2009, EPO issued $500.0 million in principal amount of Senior Notes P under this registration statement. Net proceeds from this senior note offering were used to repay the $200.0 Million Term Loan, to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes.

In September 2009, we issued 8,337,500 common units (including an over-allotment of 1,087,500 common units) to the public at an offering price of $28.00 per unit under this registration statement. We used the net proceeds of $226.4 million from the September 2009 equity offering to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes. In October 2009, EPO issued $1.1 billion in principal amount of Senior Notes Q and R under this registration statement. Net proceeds from this senior note offering were used to repay $500.0 million in aggregate principal amount of Senior Notes F that matured in October 2009, to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes.

We also have a registration statement on file with the SEC authorizing the issuance of up to 40,000,000 common units in connection with our distribution reinvestment plan ("DRIP"). A total of 32,202,131 common units have been issued under this registration statement through September 30, 2009.

In addition, we have a registration statement on file related to our employee unit purchase plan ("EUPP"), under which we can issue up to 1,200,000 common units. A total of 792,809 common units have been issued to employees under this plan through September 30, 2009.

On September 4, 2009, we agreed to issue 5,940,594 common units in a private placement to EPCO Holdings, Inc., a privately held affiliate controlled by Dan L. Duncan, for $150.0 million, or $25.25 per unit. In accordance with the terms of the private placement, as approved by the Audit, Conflicts and Governance ("ACG") Committee of EPGP's Board of Directors on September 1, 2009, the per unit purchase price of $25.25 was calculated based on a five percent discount to the five-day volume weighted average price ("5-Day VWAP") of our common units, as reported by the NYSE at the close of business on September 4, 2009. The 5-Day VWAP was based on (i) the closing price for the common units on the NYSE for each of the trading days in such five-day period and (ii) the total trading volume for the common units reported by the NYSE for each such trading day. The common units were issued on September 8, 2009.

The following table reflects the number of common units issued and the net proceeds received from underwritten and other common unit offerings completed during the nine months ended September 30, 2009:

	Net Proceeds from Sale of Common Units			
	Number of Common Units Issued	Contributed by Limited Partners	Contributed by General Partner	Total Net Proceeds
January underwritten offering	10,590,000	$ 225.6	$ 4.6	$ 230.2
February DRIP and EUPP	3,679,163	78.9	1.6	80.5
May DRIP and EUPP	3,671,679	86.1	1.8	87.9
August DRIP and EUPP	3,521,754	93.2	1.8	95.0
September private placement	5,940,594	150.0	3.1	153.1
September underwritten offering	8,337,500	226.4	4.6	231.0
Total 2009	35,740,690	$ 860.2	$ 17.5	$ 877.7

Net proceeds from the issuance of common units during 2009 have been used to temporarily reduce borrowings under EPO’s Multi-Year Revolving Credit Facility and for general partnership purposes.

Summary of Changes in Outstanding Units

The following table summarizes changes in our outstanding units since December 31, 2008:

	Common Units	Restricted Common Units	Treasury Units
Balance, December 31, 2008	439,354,731	2,080,600	--
Common units issued in connection with underwritten offerings	18,927,500	--	--
Common units issued in connection with private placement	5,940,594	--	--
Common units issued in connection with DRIP and EUPP	10,872,596	--	--
Common units issued in connection with equity awards	18,500	--	--
Restricted units issued	--	1,016,950	--
Forfeiture of restricted units	--	(194,400)	--
Conversion of restricted units to common units	244,300	(244,300)	--
Acquisition of treasury units	(64,223)	--	64,223
Cancellation of treasury units	--	--	(64,223)
Balance, September 30, 2009	475,293,998	2,658,850	--

Summary of Changes in Limited Partners’ Equity

The following table details the changes in limited partners’ equity since December 31, 2008:

	Common Units	Restricted Common Units	Total
Balance, December 31, 2008	$ 6,036.9	$ 26.2	$ 6,063.1
Net income	501.9	2.7	504.6
Operating leases paid by EPCO	0.5	--	0.5
Cash distributions to partners	(731.5)	(3.7)	(735.2)
Unit option reimbursements to EPCO	(0.5)	--	(0.5)
Net proceeds from issuance of common units	860.2	--	860.2
Proceeds from exercise of unit options	0.5	--	0.5
Acquisition of treasury units	--	(1.8)	(1.8)
Amortization of equity awards	2.8	10.7	13.5
Balance, September 30, 2009	$ 6,670.8	$ 34.1	$ 6,704.9

Distributions to Partners

We paid EPGP incentive distributions of $38.1 million and $32.0 million during the three months ended September 30, 2009 and 2008, respectively. During the nine months ended September 30, 2009 and 2008, we paid incentive distributions of $109.9 million and $92.8 million, respectively, to EPGP.

We paid aggregate distributions to our unitholders and our general partner of $860.1 million during the nine months ended September 30, 2009. These distributions pertained to the nine month period ended June 30, 2009 (i.e., the fourth quarter of 2008, and first and second quarters of 2009). On November 5, 2009, we paid a quarterly cash distribution of $0.5525 per unit with respect to the third quarter of 2009, to unitholders of record at the close of business on October 30, 2009.

Accumulated Other Comprehensive Loss

The following table presents the components of AOCI at the dates indicated:

	September 30, 2009	December 31, 2008
Commodity derivative instruments (1)	$ (84.7)	$ (114.1)
Interest rate derivative instruments (1)	14.2	3.8
Foreign currency derivative instruments (1) (2)	0.3	10.6
Foreign currency translation adjustment (2)	0.4	(1.3)
Pension and postretirement benefit plans	(0.7)	(0.7)
Subtotal	(70.5)	(101.7)
Amount attributable to noncontrolling interest	3.4	4.5
Total accumulated other comprehensive loss in partners' equity	$ (67.1)	$ (97.2)

(1) See Note 4 for additional information regarding these components of accumulated other comprehensive loss.
(2) Relates to transactions of our Canadian NGL marketing subsidiary.

Noncontrolling Interest

The following table presents the components of noncontrolling interest as presented on our Unaudited Condensed Consolidated Balance Sheets at the dates indicated:

	September 30, 2009	December 31, 2008
Limited partners of Duncan Energy Partners (1)	$ 416.9	$ 281.1
Joint venture partners (2)	108.5	112.5
AOCI attributable to noncontrolling interest	(3.4)	(4.5)
Total noncontrolling interest on consolidated balance sheets	$ 522.0	$ 389.1

(1) Consists of non-affiliate public unitholders of Duncan Energy Partners. The increase in noncontrolling interest between periods is attributable to Duncan Energy Partners' equity offering in June 2009 (see Note 12).
(2) Represents third-party ownership interests in joint ventures that we consolidate, including Seminole Pipeline Company, Tri-States Pipeline L.L.C., Independence Hub LLC and Wilprise Pipeline Company LLC.

The following table presents the components of net income attributable to noncontrolling interest as presented on our Unaudited Condensed Statements of Consolidated Operations for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Limited partners of Duncan Energy Partners	$ 10.1	$ 2.7	$ 21.8	$ 11.8
Joint venture partners	6.9	5.2	20.7	17.5
Total	$ 17.0	$ 7.9	$ 42.5	$ 29.3

The following table presents cash distributions paid to, and cash contributions from, noncontrolling interest as presented on our Unaudited Condensed Statements of Consolidated Cash Flows and Unaudited Condensed Statements of Consolidated Equity for the periods indicated:

	For the Nine Months Ended September 30, 2009	For the Nine Months Ended September 30, 2008
Cash distributions paid to noncontrolling interest:		
Limited partners of Duncan Energy Partners	$ 23.2	$ 18.5
Joint venture partners	24.7	20.7
Total cash distributions paid to noncontrolling interest	$ 47.9	$ 39.2
Cash contributions from noncontrolling interest:		
Limited partners of Duncan Energy Partners	$ 137.4	$ --

Duncan Energy Partners issued an aggregate 8,943,400 of its common units in June and July 2009, which generated net proceeds of approximately $137.4 million. Duncan Energy Partners used the net proceeds from its issuance of these units to repurchase and cancel an equal number of its common units beneficially owned by EPO.

Note 11. Business Segments

We have four reportable business segments: NGL Pipelines & Services, Onshore Natural Gas Pipelines & Services, Offshore Pipelines & Services and Petrochemical Services. Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

The following table shows our measurement of total segment gross operating margin for the periods indicated:

	For the Three Months Ended September 30, 2009	For the Three Months Ended September 30, 2008	For the Nine Months Ended September 30, 2009	For the Nine Months Ended September 30, 2008
Revenues	$ 4,596.1	$ 6,297.9	$ 11,527.1	$ 18,322.1
Less: Operating costs and expenses	(4,220.2)	(5,971.9)	(10,395.7)	(17,243.1)
Add: Equity in income of unconsolidated affiliates	22.5	14.9	18.3	48.1
Depreciation, amortization and accretion in operating costs and expenses	160.6	138.4	467.3	408.6
Non-cash impairment charge included in operating costs and expenses	1.7	--	1.7	--
Operating lease expense paid by EPCO	0.2	0.5	0.5	1.5
Gain from asset sales and related transactions in operating costs and expenses	--	(0.9)	(0.4)	(1.7)
Total segment gross operating margin	$ 560.9	$ 478.9	$ 1,618.8	$ 1,535.5

A reconciliation of our total segment gross operating margin to operating income and income before provision for income taxes follows:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Total segment gross operating margin	$ 560.9	$ 478.9	$ 1,618.8	$ 1,535.5
Adjustments to reconcile total segment gross operating margin to operating income:				
Depreciation, amortization and accretion in operating costs and expenses	(160.6)	(138.4)	(467.3)	(408.6)
Non-cash impairment charge included in operating costs and expenses	(1.7)	--	(1.7)	--
Operating lease expense paid by EPCO	(0.2)	(0.5)	(0.5)	(1.5)
Gain from asset sales and related transactions in operating costs and expenses	--	0.9	0.4	1.7
General and administrative costs	(33.9)	(21.8)	(84.7)	(67.0)
Operating income	364.5	319.1	1,065.0	1,060.1
Other expense, net	(128.0)	(101.5)	(373.7)	(287.6)
Income before provision for income taxes	$ 236.5	$ 217.6	$ 691.3	$ 772.5

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Information by segment, together with reconciliations to our consolidated totals, is presented in the following table:

	Reportable Segments					
	NGL Pipelines & Services	Onshore Natural Gas Pipelines & Services	Offshore Pipelines & Services	Petrochemical Services	Adjustments and Eliminations	Consolidated Totals
Revenues from third parties:						
Three months ended September 30, 2009	$ 3,127.7	$ 638.8	$ 98.7	$ 579.5	$ --	$ 4,444.7
Three months ended September 30, 2008	4,288.2	823.2	60.2	826.1	--	5,997.7
Nine months ended September 30, 2009	7,728.9	1,798.8	243.7	1,234.7	--	11,006.1
Nine months ended September 30, 2008	12,544.2	2,456.3	197.3	2,300.6	--	17,498.4
Revenues from related parties:						
Three months ended September 30, 2009	88.2	60.2	3.0	--	--	151.4
Three months ended September 30, 2008	140.8	154.7	4.7	--	--	300.2
Nine months ended September 30, 2009	344.1	173.1	3.8	--	--	521.0
Nine months ended September 30, 2008	501.2	314.7	7.8	--	--	823.7
Intersegment and intrasegment revenues:						
Three months ended September 30, 2009	1,592.3	121.9	0.4	135.1	(1,849.7)	--
Three months ended September 30, 2008	2,313.7	293.2	0.3	216.6	(2,823.8)	--
Nine months ended September 30, 2009	4,416.9	379.9	1.0	342.7	(5,140.5)	--
Nine months ended September 30, 2008	6,431.5	636.0	1.1	529.8	(7,598.4)	--
Total revenues:						
Three months ended September 30, 2009	4,808.2	820.9	102.1	714.6	(1,849.7)	4,596.1
Three months ended September 30, 2008	6,742.7	1,271.1	65.2	1,042.7	(2,823.8)	6,297.9
Nine months ended September 30, 2009	12,489.9	2,351.8	248.5	1,577.4	(5,140.5)	11,527.1
Nine months ended September 30, 2008	19,476.9	3,407.0	206.2	2,830.4	(7,598.4)	18,322.1
Equity in income (loss) of unconsolidated affiliates:						
Three months ended September 30, 2009	4.0	7.4	10.6	0.5	--	22.5
Three months ended September 30, 2008	3.0	5.6	6.0	0.3	--	14.9
Nine months ended September 30, 2009	7.5	21.7	(12.1)	1.2	--	18.3
Nine months ended September 30, 2008	2.3	16.9	27.9	1.0	--	48.1
Gross operating margin:						
Three months ended September 30, 2009	392.0	62.3	56.3	50.3	--	560.9
Three months ended September 30, 2008	336.1	88.1	17.5	37.2	--	478.9
Nine months ended September 30, 2009	1,088.8	252.6	150.7	126.7	--	1,618.8
Nine months ended September 30, 2008	943.5	321.2	134.4	136.4	--	1,535.5
Segment assets:						
At September 30, 2009	6,083.4	4,570.4	1,488.4	716.6	802.8	13,661.6
At December 31, 2008	5,424.1	4,033.3	1,394.5	698.2	1,604.7	13,154.8
Investments in unconsolidated affiliates: (see Note 7)						
At September 30, 2009	141.9	282.5	461.7	14.9	--	901.0
At December 31, 2008	144.2	284.0	504.8	16.5	--	949.5
Intangible assets, net: (see Note 8)						
At September 30, 2009	323.5	311.1	105.0	53.4	--	793.0
At December 31, 2008	351.0	333.5	116.2	54.7	--	855.4

Goodwill: (see Note 8)						
At September 30, 2009	269.0	282.1	82.1	73.7	--	706.9
At December 31, 2008	269.0	282.1	82.1	73.7	--	706.9

The following table provides additional information regarding our consolidated revenues (net of adjustments and eliminations) and expenses for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
NGL Pipelines & Services:				
Sales of NGLs	$ 3,054.9	$ 4,257.8	$ 7,623.0	$ 12,514.6
Sales of other petroleum and related products	0.6	0.5	1.5	1.9
Midstream services	160.4	170.7	448.5	528.9
Total	3,215.9	4,429.0	8,073.0	13,045.4
Onshore Natural Gas Pipelines & Services:				
Sales of natural gas	585.7	859.2	1,645.3	2,400.4
Midstream services	113.3	118.6	326.6	370.5
Total	699.0	977.8	1,971.9	2,770.9
Offshore Pipelines & Services:				
Sales of natural gas	0.3	0.9	0.9	2.5
Sales of other petroleum and related products	2.0	3.7	3.1	10.8
Midstream services	99.4	60.4	243.5	191.9
Total	101.7	65.0	247.5	205.2
Petrochemical Services:				
Sales of other petroleum and related products	558.8	803.4	1,165.3	2,233.7
Midstream services	20.7	22.7	69.4	66.9
Total	579.5	826.1	1,234.7	2,300.6
Total consolidated revenues	$ 4,596.1	$ 6,297.9	$ 11,527.1	$ 18,322.1
Consolidated cost and expenses:				
Operating costs and expenses:				
Cost of sales for our marketing activities	$ 3,078.1	$ 4,537.1	$ 7,462.8	$ 13,244.7
Depreciation, amortization and accretion	160.6	138.4	467.3	408.6
Gain on sale of assets and related transactions	--	(0.9)	(0.4)	(1.7)
Non-cash impairment charge	1.7	--	1.7	--
Other operating costs and expenses	979.8	1,297.3	2,464.3	3,591.5
General and administrative costs	33.9	21.8	84.7	67.0
Total consolidated costs and expenses	$ 4,254.1	$ 5,993.7	$ 10,480.4	$ 17,310.1

Changes in our revenues and operating costs and expenses period-to-period are explained in part by changes in energy commodity prices. In general, lower energy commodity prices result in a decrease in our revenues attributable to the sale of natural gas and NGLs; however, these lower commodity prices also decrease the associated cost of sales as purchase prices decline.

Note 12. Related Party Transactions

The following table summarizes our related party transactions for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Revenues from consolidated operations:				
EPCO and affiliates	$ 41.1	$ 47.2	$ 98.9	$ 91.9
Energy Transfer Equity and subsidiaries	54.5	99.6	266.5	413.0
Unconsolidated affiliates	55.8	153.4	155.6	318.8
Total	$ 151.4	$ 300.2	$ 521.0	$ 823.7
Cost of sales:				
EPCO and affiliates	$ 32.1	$ 10.9	$ 75.7	$ 36.5
Energy Transfer Equity and subsidiaries	100.6	50.6	286.5	119.4
Unconsolidated affiliates	13.0	23.7	37.5	75.9
Total	$ 145.7	$ 85.2	$ 399.7	$ 231.8
Operating costs and expenses:				
EPCO and affiliates	$ 91.8	$ 77.1	$ 258.3	$ 238.0
Energy Transfer Equity and subsidiaries	2.0	5.9	5.3	15.0
Unconsolidated affiliates	(2.5)	(3.0)	(7.7)	(7.7)
Total	$ 91.3	$ 80.0	$ 255.9	$ 245.3
General and administrative expenses:				
EPCO and affiliates	$ 16.8	$ 13.4	$ 51.2	$ 44.6
Other expense:				
EPCO and affiliates	$ 0.1	$ --	$ 0.1	$ (0.3)

The following table summarizes our related party receivable and payable amounts at the dates indicated:

	September 30, 2009	December 31, 2008
Accounts receivable - related parties:		
EPCO and affiliates	$ 27.9	$ 26.6
Energy Transfer Equity and subsidiaries	6.4	35.0
Unconsolidated affiliates	3.6	--
Total	$ 37.9	$ 61.6
Accounts payable - related parties:		
EPCO and affiliates	$ 16.9	$ 39.4
Energy Transfer Equity and subsidiaries	27.2	0.2
Unconsolidated affiliates	3.1	--
Total	$ 47.2	$ 39.6

We believe that the terms and provisions of our related party agreements are fair to us; however, such agreements and transactions may not be as favorable to us as we could have obtained from unaffiliated third parties.

Significant Relationships and Agreements with EPCO and affiliates

We have an extensive and ongoing relationship with EPCO and its affiliates, which include the following significant entities that are not a part of our consolidated group of companies:

§ EPCO and its privately held affiliates;

§ EPGP, our general partner;

- Enterprise GP Holdings, which owns and controls our general partner;

- TEPPCO and its general partner, which are our wholly owned subsidiaries; and

- the Employee Partnerships.

We also have an ongoing relationship with Duncan Energy Partners, the financial statements of which are consolidated with our own financial statements. Our transactions with Duncan Energy Partners are eliminated in consolidation. A description of our relationship with Duncan Energy Partners is presented within this Note 12.

EPCO is a privately held company controlled by Dan L. Duncan, who is also a director and Chairman of EPGP, our general partner. At September 30, 2009, EPCO and its affiliates beneficially owned 168,005,206 (or 35.2%) of our outstanding common units, which includes 13,952,402 of our common units owned by Enterprise GP Holdings. In addition, at September 30, 2009, EPCO and its affiliates beneficially owned 77.8% of the limited partner interests of Enterprise GP Holdings and 100% of its general partner, EPE Holdings. Enterprise GP Holdings owns all of the membership interests of EPGP. The principal business activity of EPGP is to act as our managing partner. The executive officers and certain of the directors of EPGP and EPE Holdings are employees of EPCO.

As our general partner, EPGP received cash distributions of $124.9 million and $106.4 million from us during the nine months ended September 30, 2009 and 2008, respectively. These amounts include incentive distributions of $109.9 million and $92.8 million for the nine months ended September 30, 2009 and 2008, respectively.

See Note 10 for information regarding the private placement of 5,940,594 common units with a privately held affiliate of EPCO in September 2009.

We and EPGP are both separate legal entities apart from each other and apart from EPCO, Enterprise GP Holdings and their respective other affiliates, with assets and liabilities that are separate from those of EPCO, Enterprise GP Holdings and their respective other affiliates. EPCO and its privately held subsidiaries depend on the cash distributions they receive from us, Enterprise GP Holdings and other investments to fund their other operations and to meet their debt obligations. EPCO and its privately held affiliates received from us and Enterprise GP Holdings $354.9 million and $300.2 million in cash distributions during the nine months ended September 30, 2009 and 2008, respectively.

EPCO ASA. We have no employees. Substantially all of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to the ASA. We, Duncan Energy Partners, Enterprise GP Holdings, TEPPCO and our respective general partners are among the parties to the ASA. Our operating costs and expenses include reimbursement payments to EPCO for the costs it incurs to operate our facilities, including compensation of EPCO's employees to the extent that such employees spend time on our businesses. We reimbursed EPCO $94.1 million for operating costs and expenses and $16.8 million for general and administrative costs for the three months ended September 30, 2009. For the nine months ended September 30, 2009, we reimbursed EPCO $267.9 million for operating costs and expenses and $51.2 million for general and administrative costs.

Relationship with TEPPCO

TEPPCO became a related party to us in February 2005 when its general partner was acquired by privately held affiliates of EPCO. Our relationship was further reinforced by the acquisition of TEPPCO's general partner by Enterprise GP Holdings in May 2007. Enterprise GP Holdings also owns our general partner. On October 26, 2009, we completed the TEPPCO Merger and TEPPCO and TEPPCO GP became our wholly owned subsidiaries. See Note 18 for additional information regarding the TEPPCO Merger.

We received $41.1 million and $47.2 million from TEPPCO for the three months ended September 30, 2009 and 2008, respectively, from the sale of hydrocarbon products. For the nine months ended September 30, 2009 and 2008, we received $98.9 million and $91.9 million from TEPPCO, respectively, from the sale of hydrocarbon products. We paid TEPPCO $29.6 million and $6.2 million for NGL pipeline transportation and storage services during the three months ended September 30, 2009 and 2008, respectively. During the nine months ended September 30, 2009 and 2008, we paid TEPPCO $65.6 million and $22.1 million, respectively, for NGL pipeline transportation and storage services.

In August 2006, we became joint venture partners with TEPPCO in Jonah. We own an approximate 19.4% interest in Jonah and TEPPCO owns the remaining 80.6% interest. Our investment in Jonah at September 30, 2009 was $250.1 million.

In August 2008, we, together with TEPPCO and Oiltanking, announced the formation of TOPS. On April 16, 2009, we, along with TEPPCO, dissociated ourselves from TOPS (see Notes 7 and 14).

In August 2009, EPO entered into a Loan Agreement (the "Loan Agreement") with TEPPCO under which EPO agreed to make an unsecured revolving loan to TEPPCO in an aggregate maximum outstanding principal amount not to exceed $100.0 million. This agreement terminated on October 26, 2009 with the closing of the TEPPCO Merger (see Note 18). TEPPCO did not execute any borrowings under this facility.

Relationship with Energy Transfer Equity

In May 2007, Enterprise GP Holdings acquired equity method investments in Energy Transfer Equity and its general partner. As a result of common control of us and Enterprise GP Holdings, Energy Transfer Equity and its consolidated subsidiaries are related parties to our consolidated businesses.

We recorded $54.5 million and $99.6 million, respectively, of revenues from Energy Transfer Partners, L.P. ("ETP"), primarily from NGL marketing activities for the three months ended September 30, 2009 and 2008. For the nine months ended September 30, 2009 and 2008, we recorded $266.5 million and $413.0 million, respectively, of revenues from ETP, primarily from NGL marketing activities. We incurred $102.6 million and $56.5 million for the three months ended September 30, 2009 and 2008, respectively, in costs of sales and operating costs and expenses. For the nine months ended September 30, 2009 and 2008, we incurred $291.8 million and $134.4 million, respectively, in costs of sales and operating costs and expenses. We have a long-term revenue generating contract with Titan Energy Partners, L.P. ("Titan"), a consolidated subsidiary of ETP. Titan purchases substantially all of its propane requirements from us. The contract continues until March 31, 2010 and contains renewal and extension options. We and Energy Transfer Company ("ETC OLP") transport natural gas on each other's systems and share operating expenses on certain pipelines. ETC OLP also sells natural gas to us.

Relationship with Duncan Energy Partners

Duncan Energy Partners was formed in September 2006 and did not acquire any assets prior to February 5, 2007, which was the date it completed its initial public offering and acquired controlling interests in five midstream energy businesses from EPO in a dropdown transaction (the "DEP I Midstream Businesses"). On December 8, 2008, through a second dropdown transaction, Duncan Energy Partners acquired controlling interests in three additional midstream energy businesses from EPO (the "DEP II Midstream Businesses"). The business purpose of Duncan Energy Partners is to acquire, own and operate a diversified portfolio of midstream energy assets and to support the growth objectives of EPO and other affiliates under common control. Duncan Energy Partners is engaged in the business of transporting and storing NGLs and petrochemical products and gathering, transporting, storing and marketing of natural gas.

At September 30, 2009, Duncan Energy Partners was owned 99.3% by its limited partners and 0.7% by its general partner, DEP GP, which is a wholly owned subsidiary of EPO. DEP GP is responsible for managing the business and operations of Duncan Energy Partners. DEP Operating Partnership, L.P., a wholly owned subsidiary of Duncan Energy Partners, conducts substantially all of Duncan Energy Partners' business. At September 30, 2009, EPO beneficially owned approximately 58% of Duncan Energy Partners' limited partner interests and 100% of its general partner.

Enterprise Products Partners has continued involvement with all of the subsidiaries of Duncan Energy Partners, including the following types of transactions: (i) it utilizes Duncan Energy Partners' storage services to support its Mont Belvieu fractionation and other businesses; (ii) it buys from, and sells to, Duncan Energy Partners natural gas in connection with its normal business activities; and (iii) it is currently the sole shipper on an NGL pipeline system located in South Texas that is owned by Duncan Energy Partners.

Duncan Energy Partners issued an aggregate 8,943,400 of its common units in June and July 2009, which generated net proceeds of approximately $137.4 million. Duncan Energy Partners used the net proceeds from its issuance of these units to repurchase and cancel an equal number of its common units beneficially owned by EPO. The repurchase of Duncan Energy Partners' common units beneficially owned by EPO was reviewed and approved by the ACG Committees of EPGP and DEP GP.

Omnibus Agreement. Under the Omnibus Agreement, EPO agreed to make additional contributions to Duncan Energy Partners as reimbursement for Duncan Energy Partners' 66% share of any excess construction costs above the (i) $28.6 million of estimated capital expenditures to complete Phase II expansions of the DEP South Texas NGL Pipeline System and (ii) $14.1 million of estimated construction costs for additional brine production capacity and above-ground storage reservoir projects at Mont Belvieu, Texas. Both projects were underway at the time of Duncan Energy Partners' initial public offering. EPO made cash contributions to Duncan Energy Partners of $1.4 million and $32.5 million in connection with the Omnibus Agreement during the nine months ended September 30, 2009 and 2008, respectively. The majority of these contributions related to funding the Phase II expansion costs of the DEP South Texas NGL Pipeline System. EPO will not receive an increased allocation of earnings or cash flows as a result of these contributions to South Texas NGL and Mont Belvieu Caverns.

Mont Belvieu Caverns' LLC Agreement. EPO made cash contributions of $14.1 million and $86.4 million under the Mont Belvieu Caverns limited liability company agreement during the nine months ended September 30, 2009 and 2008, respectively, to fund 100% of certain storage-related projects for the benefit of EPO's NGL marketing activities. At present, Mont Belvieu Caverns is not expected to generate any identifiable incremental cash flows in connection with these projects; thus, the sharing ratio for Mont Belvieu Caverns is not expected to change from the current sharing ratio of 66% for Duncan Energy Partners and 34% for EPO. EPO expects to make additional contributions of approximately $9.1 million to fund such projects during the fourth quarter of 2009. The constructed assets will be the property of Mont Belvieu Caverns.

Company and Limited Partnership Agreements – DEP II Midstream Businesses. Enterprise Holdings III, LLC ("Enterprise III") has not yet participated in expansion project spending with respect to the DEP II Midstream Businesses, although it may elect to invest in existing or future expansion projects at a later date. As a result, Enterprise GTM Holdings L.P. has funded 100% of such growth capital spending and its Distribution Base has increased from $473.4 million at December 31, 2008 to $745.7 million at September 30, 2009. The Enterprise III Distribution Base was unchanged at $730.0 million at September 30, 2009.

Relationships with Unconsolidated Affiliates

Our significant related party revenue and expense transactions with unconsolidated affiliates consist of the sale of natural gas to Evangeline and Promix. In addition, we purchase NGL storage, transportation and fractionation services from Promix and natural gas from Jonah. For additional information regarding our unconsolidated affiliates, see Note 7.

Note 13. Earnings Per Unit

The following table presents the net income available to EPGP for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Net income attributable to Enterprise Products Partners L.P.	$ 212.9	$ 203.1	$ 624.8	$ 726.0
Less incentive earnings allocations to EPGP	(38.1)	(32.0)	(109.9)	(92.8)
Net income available after incentive earnings allocation	174.8	171.1	514.9	633.2
Multiplied by EPGP ownership interest	2.0%	2.0%	2.0%	2.0%
Standard earnings allocation to EPGP	$ 3.5	$ 3.4	$ 10.3	$ 12.7
Incentive earnings allocation to EPGP	$ 38.1	$ 32.0	$ 109.9	$ 92.8
Standard earnings allocation to EPGP	3.5	3.4	10.3	12.7
Net income available to EPGP	41.6	35.4	120.2	105.5
Adjustment for ASC 260 (1)	2.5	1.1	5.3	3.2
Net income available to EPGP for EPU purposes	$ 44.1	$ 36.5	$ 125.5	$ 108.7

(1) For purposes of computing basic and diluted earnings per unit ("EPU"), the master limited partnerships subsections of ASC 260 have been applied.

The following table presents our calculation of basic and diluted earnings per unit for the periods indicated:

	For the Three Month Ended September 30,		For the Nine Month Ended September 30,	
	2009	2008	2009	2008
BASIC EARNINGS PER UNIT				
Numerator				
Net income attributable to Enterprise Products Partners L.P.	$ 212.9	$ 203.1	$ 624.8	$ 726.0
Net income available to EPGP for EPU purposes	(44.1)	(36.5)	(125.5)	(108.7)
Net income available to limited partners	$ 168.8	$ 166.6	$ 499.3	$ 617.3
Denominator				
Weighted – average common units	461.5	435.3	456.0	434.6
Weighted – average time-vested restricted units	2.8	2.3	2.4	2.0
Total	464.3	437.6	458.4	436.6
Basic earnings per unit				
Net income per unit before EPGP earnings allocation	$ 0.45	$ 0.46	$ 1.36	$ 1.66
Net income available to EPGP	(0.09)	(0.08)	(0.27)	(0.25)
Net income available to limited partners	$ 0.36	$ 0.38	$ 1.09	$ 1.41
DILUTED EARNINGS PER UNIT				
Numerator				
Net income attributable to Enterprise Products Partners L.P.	$ 212.9	$ 203.1	$ 624.8	$ 726.0
Net income available to EPGP for EPU purposes	(44.1)	(36.5)	(125.5)	(108.7)
Net income available to limited partners	$ 168.8	$ 166.6	$ 499.3	$ 617.3
Denominator				
Weighted – average common units	461.5	435.3	456.0	434.6
Weighted – average time-vested restricted units	2.8	2.3	2.4	2.0
Incremental option units	0.1	0.2	0.1	0.3
Total	464.4	437.8	458.5	436.9
Diluted earnings per unit				
Net income per unit before EPGP earnings allocation	$ 0.45	$ 0.46	$ 1.36	$ 1.66
Net income available to EPGP	(0.09)	(0.08)	(0.27)	(0.25)
Net income available to limited partners	$ 0.36	$ 0.38	$ 1.09	$ 1.41

ENTERPRISE PRODUCTS PARTNERS L.P.
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Note 14. Commitments and Contingencies

Litigation

On occasion, we or our unconsolidated affiliates are named as a defendant in litigation and legal proceedings, including regulatory and environmental matters. Although we are insured against various risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings. We are unaware of any litigation, pending or threatened, that we believe is reasonably likely to have a significant adverse effect on our financial position, results of operations or cash flows.

We evaluate our ongoing litigation based upon a combination of litigation and settlement alternatives. These reviews are updated as the facts and combinations of the cases develop or change. Assessing and predicting the outcome of these matters involves substantial uncertainties. In the event that the assumptions we used to evaluate these matters change in future periods or new information becomes available, we may be required to record a liability for an adverse outcome. In an effort to mitigate potential adverse consequences of litigation, we could also seek to settle legal proceedings brought against us. We have not recorded any significant reserves for any litigation in our financial statements.

On September 18, 2006, Peter Brinckerhoff, a purported unitholder of TEPPCO, filed a complaint in the Court of Chancery of the State of Delaware (the “Delaware Court”), in his individual capacity, as a putative class action on behalf of other unitholders of TEPPCO and derivatively on behalf of TEPPCO, concerning, among other things, certain transactions involving TEPPCO and us or our affiliates. Mr. Brinckerhoff filed an amended complaint on July 12, 2007. The amended complaint names as defendants (i) TEPPCO, certain of its current and former directors, and certain of its affiliates, (ii) us and certain of our affiliates, (iii) EPCO and (iv) Dan L. Duncan.

The amended complaint alleges, among other things, that the defendants caused TEPPCO to enter into specified transactions that were unfair to TEPPCO or otherwise unfairly favored us or our affiliates over TEPPCO. These transactions are alleged to include: (i) the joint venture to further expand the Jonah system entered into by TEPPCO and us in August 2006 (the plaintiff alleges that TEPPCO did not receive fair value for allowing us to participate in the joint venture); (ii) the sale by TEPPCO of its Pioneer natural gas processing plant and certain gas processing rights to us in March 2006 (the plaintiff alleges that the purchase price we paid did not provide fair value to TEPPCO); and (iii) certain amendments to TEPPCO’s partnership agreement, including a reduction in the maximum tier of TEPPCO’s incentive distribution rights in exchange for TEPPCO units. The amended complaint seeks (i) rescission of the amendments to TEPPCO’s partnership agreement, (ii) damages for profits and special benefits allegedly obtained by defendants as a result of the alleged wrongdoings in the amended complaint and (iii) an award to plaintiff of the costs of the action, including fees and expenses of his attorneys and experts. By its Opinion and Order dated November 25, 2008, the Delaware Court dismissed Mr. Brinckerhoff’s individual and putative class action claims with respect to the amendments to TEPPCO’s partnership agreement. We refer to this action and the remaining claims in this action as the “Derivative Action.”

On April 29, 2009, Peter Brinckerhoff and Renee Horowitz, as Attorney in Fact for Rae Kenrow, purported unitholders of TEPPCO, filed separate complaints in the Delaware Court as putative class actions on behalf of other unitholders of TEPPCO, concerning the TEPPCO Merger. On May 11, 2009, these actions were consolidated under the caption Texas Eastern Products Pipeline Company, LLC Merger Litigation, C.A. No. 4548-VCL (“Merger Action”). The complaints name as defendants us, EPGP, TEPPCO GP, the directors of TEPPCO GP, EPCO and Dan L. Duncan.

The Merger Action complaints allege, among other things, that the terms of the merger (as proposed as of the time the Merger Action complaints were filed) are grossly unfair to TEPPCO’s unitholders and that the TEPPCO Merger is an attempt to extinguish the Derivative Action without consideration. The complaints further allege that the process through which the Special Committee of the ACG Committee of TEPPCO GP was appointed to consider the TEPPCO Merger is contrary to the spirit and intent of TEPPCO's partnership agreement and constitutes a breach of the implied covenant of fair dealing.

The complaints seek relief (i) enjoining the defendants and all persons acting in concert with them from pursuing the TEPPCO Merger, (ii) rescinding the TEPPCO Merger to the extent it is consummated, or awarding rescissory damages in respect thereof, (iii) directing the defendants to account for all damages suffered or to be suffered by the plaintiffs and the purported class as a result of the defendants' alleged wrongful conduct, and (iv) awarding plaintiffs' costs of the actions, including fees and expenses of their attorneys and experts.

On June 28, 2009, the parties entered into a Memorandum of Understanding pursuant to which we, TEPPCO, EPCO, TEPPCO GP, all other individual defendants and the plaintiffs have proposed to settle the Merger Action and the Derivative Action. The Memorandum of Understanding contemplated that the parties would enter into a stipulation of settlement within 30 days from the date of the Memorandum of Understanding. On August 5, 2009, the parties entered into a Stipulation and Agreement of Compromise, Settlement and Release (the "Settlement Agreement") contemplated by the Memorandum of Understanding. Pursuant to the Settlement Agreement, the board of directors of TEPPCO GP recommended to TEPPCO's unitholders that they approve the adoption of the merger agreement and took all necessary steps to seek unitholder approval for the merger as soon as practicable. Pursuant to the Settlement Agreement, approval of the merger required, in addition to votes required under TEPPCO's partnership agreement, that the actual votes cast in favor of the proposal by holders of TEPPCO's outstanding units, excluding those held by defendants to the Derivative Action, exceed the actual votes cast against the proposal by those holders. The Settlement Agreement further provides that the Derivative Action was considered by TEPPCO GP's Special Committee to be a significant TEPPCO benefit for which fair value was obtained in the merger consideration.

The Settlement Agreement is subject to customary conditions, including Delaware Court approval. A hearing regarding approval of the Settlement Agreement by the Delaware Court was held on October 12, 2009, but the Delaware Court has yet to rule on the settlement. There can be no assurance that the Delaware Court will approve the settlement in the Settlement Agreement. In such event, the proposed settlement as contemplated by the Settlement Agreement may be terminated. Among other things, the plaintiffs' agreement to settle the Derivative Action and Merger Action litigation, including their agreement to the fairness of the terms and process of the merger negotiations, is subject to (i) the drafting and execution of other such documentation as may be required to obtain final Delaware Court approval and dismissal of the actions, (ii) Delaware Court approval and the mailing of the notice of settlement which sets forth the terms of settlement to TEPPCO's unitholders, (iii) consummation of the TEPPCO Merger and (iv) final Delaware Court certification and approval of the settlement and dismissal of the actions. See Notes 12 and 18 for additional information regarding our relationship with TEPPCO, including information related to the TEPPCO Merger.

Additionally, on June 29 and 30, 2009, respectively, M. Lee Arnold and Sharon Olesky, purported unitholders of TEPPCO, filed separate complaints in the District Courts of Harris County, Texas, as putative class actions on behalf of other unitholders of TEPPCO, concerning the TEPPCO Merger (the "Texas Actions"). The complaints name as defendants us, TEPPCO, TEPPCO GP, EPGP, EPCO, Dan L. Duncan, Jerry Thompson, and the board of directors of TEPPCO GP. The allegations in the complaints are similar to the complaints filed in Delaware on April 29, 2009 and seek similar relief. The named plaintiffs in the two Texas Actions (the "Texas Plaintiffs/Objectors") have also appeared in the Delaware proceedings as objectors to the settlement of those cases which are awaiting court approval. On October 7, 2009, the Texas Plaintiffs/Objectors and the parties to the Settlement Agreement entered into a Stipulation to Withdraw Objection (the "Stipulation"). In accordance with the Stipulation, TEPPCO made certain supplemental disclosures and, if the Settlement Agreement obtains Final Court Approval (as defined in the Settlement Agreement), the Texas Plaintiffs/Objectors have agreed to dismiss the Texas Actions with prejudice and, pending such Final Court Approval, will take no action to prosecute the Texas Actions.

In February 2007, EPO received a letter from the Environment and Natural Resources Division of the U.S. Department of Justice related to an ammonia release in Kingman County, Kansas on October 27, 2004 from a pressurized anhydrous ammonia pipeline owned by a third party, Magellan Ammonia Pipeline, L.P. (“Magellan”), and a previous release of ammonia on September 27, 2004 from the same pipeline. EPO was the operator of this pipeline until July 1, 2008. This matter was settled in September 2009, and Magellan has agreed to pay all assessed penalties.

The Attorney General of Colorado on behalf of the Colorado Department of Public Health and Environment filed suit against us and others on April 15, 2008 in connection with the construction of a pipeline near Parachute, Colorado. The State sought a temporary restraining order and an injunction to halt construction activities since it alleged that the defendants failed to install measures to minimize damage to the environment and to follow requirements for the pipeline’s stormwater permit and appropriate stormwater plan. We have entered into a settlement agreement with the State that dismisses the suit and assesses a fine of approximately $0.2 million.

In January 2009, the State of New Mexico filed suit in District Court in Santa Fe County, New Mexico, under the New Mexico Air Quality Control Act. The lawsuit arose out of a February 27, 2008 Notice Of Violation issued to Marathon Oil Corp. (“Marathon”) as operator of the Indian Basin natural gas processing facility located in Eddy County, New Mexico. We own a 42.4% undivided interest in the assets comprising the Indian Basin facility. The State alleges violations of its air laws, and Marathon is attempting to negotiate an acceptable resolution with the state. The State seeks penalties and remedial projects above $0.1 million. Marathon continues to work with the State to determine if resolution of the case is possible. We believe that any potential penalties will not have a material impact on our consolidated financial position, results of operations or cash flows.

In connection with the dissociation of TEPPCO and us from TOPS (see Note 7), Oiltanking filed an original petition against Enterprise Offshore Port System, LLC, EPO, TEPPCO O/S Port System, LLC, TEPPCO and TEPPCO GP in the District Court of Harris County, Texas, 61st Judicial District (Cause No. 2009-31367), asserting, among other things, that the dissociation was wrongful and in breach of the TOPS partnership agreement, citing provisions of the agreement that, if applicable, would continue to obligate us and TEPPCO to make capital contributions to fund the project and impose liabilities on us and TEPPCO. On September 17, 2009, we and TEPPCO entered into a settlement agreement with certain affiliates of Oiltanking and TOPS that resolved all disputes between the parties related to the business and affairs of the TOPS project (including the litigation described above). We and TEPPCO each recognized approximately $33.5 million of expense during the third quarter of 2009 in connection with this settlement. This charge is classified within our Offshore Pipelines & Services business segment.

Regulatory Matters

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as “greenhouse gases” or “GHGs” and including carbon dioxide and methane, may be contributing to climate change. On April 17, 2009, the U.S. Environmental Protection Agency (“EPA”) issued a notice of its proposed finding and determination that emission of carbon dioxide, methane, and other GHGs present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth’s atmosphere. The EPA’s finding and determination would allow it to begin regulating emissions of GHGs under existing provisions of the federal Clean Air Act. Although it may take the EPA several years to adopt and impose regulations limiting emissions of GHGs, any such regulation could require us to incur costs to reduce emissions of GHGs associated with our operations. In addition, on June 26, 2009, the U.S. House of Representatives approved adoption of the “American Clean Energy and Security Act of 2009,” also known as the “Waxman-Markey cap-and-trade legislation” or “ACESA.” ACESA would establish an economy-wide cap on emissions of GHGs in the United States and would require most sources of GHG emissions to obtain GHG emission “allowances” corresponding to their annual emissions of GHGs. The U.S. Senate has also begun work on its own legislation for controlling and reducing emissions of GHGs in the United States. Any laws or regulations that may be adopted to restrict or reduce emissions of GHGs would likely require us to incur increased operating costs, and may have an adverse effect on our business, financial position, demand for our operations, results of operations and cash flows.

Contractual Obligations

Scheduled maturities of long-term debt. See Notes 9 and 18 for information regarding changes in our consolidated debt obligations.

Operating lease obligations. During the second quarter of 2009, we entered into a 20-year right-of-way agreement with the Jicarilla Apache Nation in support of continued natural gas gathering activities on our San Juan gathering system in Northwest New Mexico. Pending approval of this agreement by the U.S. Department of the Interior, our minimum lease obligations will be $3.0 million for the first year and $2.0 million per year for each of the next succeeding four years. Aggregate minimum lease commitments are $43.3 million over the 20-year contractual term. The agreement also provides for contingent rentals that are calculated annually based on actual throughput volumes and then current natural gas and NGL prices. Our agreement with the Jicarilla Apache Nation does not provide for renewal options beyond the 20-year lease term.

Prior to May 2009, we leased rail and truck terminal facilities in Mont Belvieu, Texas from Martin. At December 31, 2008, our remaining aggregate minimum lease commitments under this agreement were $56.8 million through the contractual term ending in 2023. The lease agreement with Martin was terminated upon our acquisition of such facilities in May 2009. See Note 6 for additional information regarding our acquisition of certain rail and truck terminal facilities from Martin.

Except for the foregoing, there have been no material changes in our operating lease commitments since December 31, 2008. Lease and rental expense was $11.4 million and $8.5 million during the three months ended September 30, 2009 and 2008, respectively. For the nine months ended September 30, 2009 and 2008, lease and rental expense was $31.0 million and $26.9 million, respectively.

Purchase obligations. Apart from that discussed below, there have been no material changes in our consolidated purchase obligations since December 31, 2008.

As a result of our dissociation from TOPS, capital expenditure commitments decreased by an estimated $68.0 million from that reported in our Recast Form 8-K. See Note 7 for additional information regarding TOPS.

Other Claims

As part of our normal business activities with joint venture partners and certain customers and suppliers, we occasionally have claims made against us as a result of disputes related to contractual agreements or similar arrangements. As of September 30, 2009, claims against us totaled approximately $4.6 million. These matters are in various stages of assessment and the ultimate outcome of such disputes cannot be reasonably estimated. However, in our opinion, the likelihood of a material adverse outcome related to disputes against us is remote. Accordingly, accruals for loss contingencies related to these matters, if any, that might result from the resolution of such disputes have not been reflected in our consolidated financial statements.

Note 15. Significant Risks and Uncertainties

Insurance Matters

EPCO completed its annual insurance renewal process during the second quarter of 2009. In light of recent hurricane and other weather-related events, the renewal of policies for weather-related risks resulted in significant increases in premiums and certain deductibles, as well as changes in the scope of coverage.

EPCO's deductible for onshore physical damage from windstorms increased from $10.0 million per storm to $25.0 million per storm. EPCO's onshore program currently provides $150.0 million per occurrence for named windstorm events compared to $175.0 million per occurrence in the prior year. With respect to offshore assets, the windstorm deductible increased significantly from $10.0 million per storm (with a one-time aggregate deductible of $15.0 million) to $75.0 million per storm. EPCO's offshore program currently provides $100.0 million in the aggregate compared to $175.0 million in the aggregate for the prior year. For non-windstorm events, EPCO's deductible for both onshore and offshore physical damage remained at $5.0 million per occurrence. For certain of our major offshore assets, our producer customers have agreed to provide a specified level of physical damage insurance for named windstorms. For example, the producers associated with our Independence Hub and Marco Polo platforms have agreed to cover windstorm generated physical damage costs up to $250.0 million for each platform.

Business interruption coverage in connection with a windstorm event remains in place for onshore assets, but was eliminated for offshore assets. Onshore assets covered by business interruption insurance must be out-of-service in excess of 60 days before any losses from business interruption will be covered. Furthermore, pursuant to the current policy, we will now absorb 50% of the first $50.0 million of any loss in excess of deductible amounts for our onshore assets.

In the third quarter of 2008, certain of our onshore and offshore facilities located along the Gulf Coast of Texas and Louisiana were damaged by Hurricanes Gustav and Ike. The disruptions in hydrocarbon production caused by these storms resulted in decreased volumes for some of our pipeline systems, natural gas processing plants, NGL fractionators and offshore platforms, which in turn caused a decrease in gross operating margin from these operations. As a result of our share of EPCO's insurance deductibles for windstorm coverage, we expensed a combined cumulative total of $47.6 million of repair costs for property damage in connection with these two storms through September 30, 2009. We continue to file property damage claims in connection with the damage caused by these storms. We recognize business interruption proceeds as income when they are received in cash.

The following table summarizes proceeds we received during the periods indicated from business interruption and property damage insurance claims with respect to certain named storms:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	**2008**	**2009**	**2008**
Business interruption proceeds:				
Hurricane Katrina	$ --	$ --	$ --	$ 0.5
Hurricane Rita	--	--	--	0.7
Hurricane Ike	19.2	--	19.2	--
Total business interruption proceeds	19.2	--	19.2	1.2
Property damage proceeds:				
Hurricane Ivan	0.7	--	0.7	--
Hurricane Katrina	3.5	2.5	26.7	9.4
Hurricane Rita	--	--	--	2.7
Total property damage proceeds	4.2	2.5	27.4	12.1
Total	$ 23.4	$ 2.5	$ 46.6	$ 13.3

At September 30, 2009, we have $22.6 million of estimated property damage claims outstanding related to storms that we believe are probable of collection during the next twelve months and $45.2 million thereafter. To the extent we estimate the dollar value of such damages, please be aware that a change in our estimates may occur, if and when additional information becomes available.

Credit Risk due to Industry Concentrations

Our largest customer for 2008 was LyondellBassell Industries and its affiliates ("LBI"), which accounted for 9.6% of our consolidated revenues during 2008. On January 6, 2009, LBI announced that its U.S. operations had voluntarily filed to reorganize under Chapter 11 of the U.S. Bankruptcy Code. At the time of the bankruptcy filing, we had approximately $10.0 million of net credit exposure to LBI. We resolved our outstanding claims with LBI in October 2009 with no gain or loss being recorded in connection with the settlement. We continue to do business with this important customer; however, we continue to manage our credit exposure to LBI.

Note 16. Supplemental Cash Flow Information

The following table provides information regarding the net effect of changes in our operating assets and liabilities for the periods indicated:

	For the Nine Months Ended September 30, 2009	For the Nine Months Ended September 30, 2008
Decrease (increase) in:		
Accounts and notes receivable – trade	$ (286.0)	$ 91.6
Accounts receivable – related parties	37.2	(6.7)
Inventories	(799.2)	(299.1)
Prepaid and other current assets	3.0	(43.9)
Other assets	(24.6)	24.2
Increase (decrease) in:		
Accounts payable – trade	8.3	(57.2)
Accounts payable – related parties	8.0	51.2
Accrued product payables	537.5	14.2
Accrued interest payable	(3.0)	27.2
Other accrued expenses	(34.8)	(29.0)
Other current liabilities	(30.8)	7.7
Other liabilities	(5.6)	(8.6)
Net effect of changes in operating accounts	$ (590.0)	$ (228.4)

We incurred liabilities for construction in progress that had not been paid at September 30, 2009 and December 31, 2008 of $109.2 million and $91.6 million, respectively. Such amounts are not included under the caption “Capital expenditures” on the Unaudited Condensed Statements of Consolidated Cash Flows.

Note 17. Condensed Consolidated Financial Information of EPO

EPO conducts substantially all of our business. Currently, we have no independent operations and no material assets outside those of EPO. EPO consolidates the financial statements of Duncan Energy Partners with its own financial statements.

Enterprise Products Partners L.P. guarantees the debt obligations of EPO, with the exception of Duncan Energy Partners’ debt obligations. If EPO were to default on any of its guaranteed debt, Enterprise Products Partners L.P. would be responsible for full repayment of that obligation. See Note 9 for additional information regarding our consolidated debt obligations.

The reconciling items between our consolidated financial statements and those of EPO are insignificant. The following table presents condensed consolidated balance sheet data for EPO at the dates indicated:

	September 30, 2009	December 31, 2008
ASSETS		
Current assets	$ 3,149.8	$ 2,175.6
Property, plant and equipment, net	13,661.6	13,154.8
Investments in unconsolidated affiliates	901.0	949.5
Intangible assets, net	793.0	855.4
Goodwill	706.9	706.9
Other assets	145.1	126.6
Total	$ 19,357.4	$ 17,968.8
LIABILITIES AND EQUITY		
Current liabilities	$ 2,689.4	$ 2,222.7
Long-term debt	9,198.3	9,108.4
Other long-term liabilities	165.5	147.3
Equity	7,304.2	6,490.4
Total	$ 19,357.4	$ 17,968.8
Total EPO debt obligations guaranteed Enterprise Products Partners L.P.	$ 8,682.2	$ 8,561.8

The following table presents condensed consolidated statements of operations data for EPO for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Revenues	$ 4,596.1	$ 6,297.9	$ 11,527.1	$ 18,322.1
Costs and expenses	4,245.8	5,993.4	10,465.6	17,308.5
Equity in income of unconsolidated affiliates	22.5	14.9	18.3	48.1
Operating income	372.8	319.4	1,079.8	1,061.7
Other expense	(128.0)	(101.5)	(373.7)	(287.7)
Income before provision for income taxes	244.8	217.9	706.1	774.0
Provision for income taxes	(6.6)	(6.6)	(24.0)	(17.2)
Net income	238.2	211.3	682.1	756.8
Net income attributable to the noncontrolling interest	(17.0)	(8.0)	(42.7)	(29.4)
Net income attributable to EPO	$ 221.2	$ 203.3	$ 639.4	$ 727.4

Note 18. Subsequent Events

Issuance of Senior Notes Q and R

On October 5, 2009, EPO issued $500.0 million in principal amount of 10-year unsecured Senior Notes Q and $600.0 million in principal amount of 30-year unsecured Senior Notes R. Senior Notes Q were issued at 99.355% of their principal amount, have a fixed interest rate of 5.25% and mature on January 31, 2020. Senior Notes R were issued at 99.386% of their principal amount, have a fixed interest rate of 6.125% and mature on October 15, 2039. Net proceeds from the issuance of Senior Notes Q and R were used (i) to repay $500.0 million in aggregate principal amount of Senior Notes F that matured in October 2009, (ii) to temporarily reduce borrowings outstanding under EPO’s Multi-Year Revolving Credit Facility and (iii) for general partnership purposes.

Senior Notes Q and R rank equal with EPO’s existing and future unsecured and unsubordinated indebtedness. They are senior to any existing and future subordinated indebtedness of EPO. Senior Notes Q and R are subject to make-whole redemption rights and were issued under indentures containing certain covenants, which generally restrict EPO's ability, with certain exceptions, to incur debt secured by liens and engage in sale and leaseback transactions.

Completion of TEPPCO Merger

On October 26, 2009, the related mergers of our wholly owned subsidiaries with TEPPCO and TEPPCO GP were completed. Under terms of the merger agreements, TEPPCO and TEPPCO GP became wholly owned subsidiaries of ours and each of TEPPCO's unitholders, except for a privately held affiliate of EPCO, were entitled to receive 1.24 of our common units for each TEPPCO unit. In total, we issued an aggregate of 126,932,318 common units and 4,520,431 Class B units (described below) as consideration in the TEPPCO Merger for both TEPPCO units and the TEPPCO GP membership interests. TEPPCO's units, which had been trading on the NYSE under the ticker symbol TPP, have been delisted and are no longer publicly traded.

A privately held affiliate of EPCO exchanged a portion of its TEPPCO units, based on the 1.24 exchange rate, for 4,520,431 of our Class B units in lieu of common units. The Class B units are not entitled to regular quarterly cash distributions for the first sixteen quarters following the closing date of the merger. The Class B units automatically convert into the same number of common units on the date immediately following the payment date for the sixteenth quarterly distribution following the closing date of the merger. The Class B units are entitled to vote together with the common units as a single class on partnership matters and, except for the payment of distributions, have the same rights and privileges as our common units.

Under the terms of the TEPPCO Merger agreements, Enterprise GP Holdings received 1,331,681 of our common units and an increase in the capital account of EPGP to maintain its 2% general partner interest in us as consideration for 100% of the membership interests of TEPPCO GP. Following the closing of the TEPPCO Merger, affiliates of EPCO owned approximately 31.3% of our outstanding limited partner units, including 3.4% owned by Enterprise GP Holdings.

The post-merger partnership, which retains the name Enterprise Products Partners L.P., accesses the largest producing basins of natural gas, NGLs and crude oil in the U.S., and serves some of the largest consuming regions for natural gas, NGLs, refined products, crude oil and petrochemicals. The post-merger partnership owns almost 48,000 miles of pipelines comprised of over 22,000 miles of NGL, refined product and petrochemical pipelines, over 20,000 miles of natural gas pipelines and more than 5,000 miles of crude oil pipelines. The merged partnership's logistical assets include approximately 200 MMBbls of NGL, refined product and crude oil storage capacity; 27 Bcf of natural gas storage capacity; one of the largest NGL import/export terminals in the U.S., located on the Houston Ship Channel; 60 NGL, refined product and chemical terminals spanning the U.S. from the west coast to the east coast; and crude oil import terminals on the Texas Gulf Coast. The post-merger partnership owns interests in 17 fractionation plants with over 600 thousand barrels per day ("MBPD") of net capacity; 25 natural gas processing plants with a net capacity of approximately 9 Bcf/d; and 3 butane isomerization facilities with a capacity of 116 MBPD. The post-merger partnership is also one of the largest inland tank barge companies in the U.S.

The merger transactions will be accounted for as a reorganization of entities under common control in a manner similar to a pooling of interests. The financial and operating activities of Enterprise Products Partners, TEPPCO and Enterprise GP Holdings and their respective general partners, and EPCO and its privately held subsidiaries, are under the common control of Dan L. Duncan.

We incurred $14.4 million of merger-related expenses during the nine months ended September 30, 2009 that are reflected as a component of general and administrative costs.

The following table presents selected unaudited pro forma earnings information for the periods presented as if the TEPPCO Merger had occurred on January 1 of each period. The selected unaudited pro forma earnings information is based on assumptions that we believe are reasonable under the circumstances and are intended for informational purposes only. They are not necessarily indicative of the financial results that would have occurred if the TEPPCO Merger had taken place on the dates indicated, nor are they indicative of the future consolidated results of the post-merger partnership. Amounts presented in the table are in millions, except per unit amounts.

	For the Nine Months Ended September 30,	
	2009	2008
Revenues	$ 17,110.5	$ 29,544.1
Costs and expenses	15,863.5	28,251.0
Operating income	1,210.6	1,325.0
Net income	714.3	912.8
Basic EPU:		
Units outstanding, as reported	458.4	436.6
Units outstanding, pro forma	585.3	563.5
Basic EPU, as reported	$ 1.09	$ 1.41
Basic EPU, pro forma	$ 0.88	$ 1.32
Diluted EPU:		
Units outstanding, as reported	458.5	436.9
Units outstanding, pro forma	590.0	568.4
Diluted EPU, as reported	$ 1.09	$ 1.41
Diluted EPU, pro forma	$ 0.87	$ 1.31

In connection with the TEPPCO Merger, EPO commenced offers in September 2009 to exchange all of TEPPCO's outstanding notes for a corresponding series of new EPO notes. The purpose of the exchange offer was to simplify our capital structure following the TEPPCO Merger. The exchanges were completed on October 27, 2009. The new EPO notes are guaranteed by Enterprise Products Partners L.P.   As presented in the following table, the aggregate principal amount of the TEPPCO notes was $2 billion, of which $1.95 billion was exchanged:

TEPPCO Notes Exchanged	Principal Amount Exchanged	Principal Amount Remaining
7.625% Senior Notes due 2012	$ 490.5	$ 9.5
6.125% Senior Notes due 2013	182.5	17.5
5.90% Senior Notes due 2013	237.6	12.4
6.65% Senior Notes due 2018	349.7	0.3
7.55% Senior Notes due 2038	399.6	0.4
7.00% Junior Fixed/Floating Subordinated Notes due 2067	285.8	14.2
	$ 1,945.7	$ 54.3

The EPO notes issued in the exchange will be recorded at the same carrying value as the TEPPCO notes being replaced. Accordingly, we will recognize no gain or loss for accounting purposes related to this exchange. All note exchange direct costs paid to third parties will be expensed.

In addition to the debt exchange, we gained approval from the requisite TEPPCO noteholders to eliminate substantially all of the restrictive covenants and reporting requirements associated with the remaining TEPPCO notes.

Upon the consummation of the TEPPCO Merger, EPO repaid and terminated indebtedness under TEPPCO's revolving credit facility.

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

For the three and nine months ended September 30, 2009 and 2008.

The following information should be read in conjunction with our unaudited condensed consolidated financial statements and accompanying notes included in this report. The following information and such unaudited condensed consolidated financial statements should also be read in conjunction with the financial statements and related notes, together with our discussion and analysis of financial position and results of operations included in our Current Report on Form 8-K dated July 8, 2009 (the "Recast Form 8-K"), which retroactively adjusted portions of our Annual Report for the year ended December 31, 2008. The Recast Form 8-K reflects our adoption of the provisions under Accounting Standards Codification ("ASC") 810, Consolidation, related to noncontrolling interests, our adoption of the provisions under ASC 260, Earnings Per Share, pertaining to the application of the two-class method to master limited partnerships in computing basic and diluted earnings per share, and the resulting change in presentation and disclosure requirements.

Our financial statements have been prepared in accordance with U.S. generally accepted accounting principles ("GAAP").

Key References Used in this Quarterly Report

Enterprise Products Partners L.P. is a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "EPD." Unless the context requires otherwise, references to "we," "us," "our," or "Enterprise Products Partners" are intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries.

References to "EPO" mean Enterprise Products Operating LLC, which is a wholly owned subsidiary of Enterprise Products Partners through which Enterprise Products Partners conducts substantially all of its business.

References to "Duncan Energy Partners" mean Duncan Energy Partners L.P., which is a consolidated subsidiary of EPO and a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "DEP." References to "DEP GP" mean DEP Holdings, LLC, which is the general partner of Duncan Energy Partners and is wholly owned by EPO.

References to "EPGP" mean Enterprise Products GP, LLC, which is our general partner.

References to "Enterprise GP Holdings" mean Enterprise GP Holdings L.P., a publicly traded limited partnership, the units of which are listed on the NYSE under the ticker symbol "EPE." Enterprise GP Holdings owns EPGP. References to "EPE Holdings" mean EPE Holdings, LLC, which is the general partner of Enterprise GP Holdings.

References to "TEPPCO" and "TEPPCO GP" mean TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (which is the general partner of TEPPCO) prior to their mergers with our subsidiaries. On October 26, 2009, we completed our merger with TEPPCO and TEPPCO GP (such related mergers referred to herein individually and together as the "TEPPCO Merger"). For additional information regarding the TEPPCO Merger, see "Recent Developments" included within this Item 2.

References to "Energy Transfer Equity" mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries, which include Energy Transfer Partners, L.P. Energy Transfer Equity is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "ETE." The general partner of Energy Transfer Equity is LE GP, LLC ("LE GP"). Enterprise GP Holdings owns a noncontrolling interest in both LE GP and Energy Transfer Equity. Enterprise GP Holdings accounts for its investments in LE GP and Energy Transfer Equity using the equity method of accounting.

References to "EPCO" mean EPCO, Inc. and its wholly owned, privately held affiliates, which are related parties to all of the foregoing named entities.

We, EPO, Duncan Energy Partners, DEP GP, EPGP, Enterprise GP Holdings, EPE Holdings, TEPPCO and TEPPCO GP are affiliates under the common control of Dan L. Duncan, the Group Co-Chairman and controlling shareholder of EPCO.

As generally used in the energy industry and in this discussion, the identified terms have the following meanings:

/d	= per day
BBtus	= billion British thermal units
MBPD	= thousand barrels per day
MMBbls	= million barrels
MMBtus	= million British thermal units
MMcf	= million cubic feet
Bcf	= billion cubic feet

Cautionary Note Regarding Forward-Looking Statements

This discussion contains various forward-looking statements and information that are based on our beliefs and those of our general partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as "anticipate," "project," "expect," "plan," "seek," "goal," "estimate," "forecast," "intend," "could," "should," "will," "believe," "may," "potential" and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our general partner believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any assurances that such expectations will prove to be correct. Such statements are subject to a variety of risks, uncertainties and assumptions as described in more detail in Item 1A "Risk Factors" included in our Annual Report on Form 10-K for 2008. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements. The forward-looking statements in this Quarterly Report speak only as of the date hereof. Except as required by federal and state securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason.

Critical Accounting Policies and Estimates

A summary of the significant accounting policies we have adopted and followed in the preparation of our consolidated financial statements is included in our Recast Form 8-K. Certain of these accounting policies require the use of estimates. As more fully described therein, the following estimates, in our opinion, are subjective in nature, require the exercise of judgment and involve complex analysis: depreciation methods and estimated useful lives of property, plant and equipment; measuring recoverability of long-lived assets and equity method investments; amortization methods and estimated useful lives of qualifying intangible assets; methods we employ to measure the fair value of goodwill; revenue recognition policies and use of estimates for revenues and expenses; reserves for environmental matters; and natural gas imbalances. These estimates are based on our current knowledge and understanding and may change as a result of actions we may take in the future. Changes in these estimates will occur as a result of the passage of time and the occurrence of future events. Subsequent changes in these estimates may have a significant impact on our financial position, results of operations and cash flows.

Overview of Business

We are a North American midstream energy company providing a wide range of services to producers and consumers of natural gas, natural gas liquids ("NGLs"), crude oil and certain petrochemicals. In addition, we are an industry leader in the development of pipeline and other midstream energy infrastructure in the continental United States and Gulf of Mexico. We are a publicly traded Delaware limited partnership formed in 1998, the common units of which are listed on the NYSE under the ticker symbol "EPD."

Our midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States, Canada and the Gulf of Mexico to domestic consumers and international markets. We have four reportable business segments: NGL Pipelines & Services; Onshore Natural Gas Pipelines & Services; Offshore Pipelines & Services; and Petrochemical Services. Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold.

We conduct substantially all of our business through EPO. We are owned 98% by our limited partners and 2% by our general partner, EPGP. EPGP is owned 100% by Enterprise GP Holdings.

Recent Developments

The following information highlights our significant developments since January 1, 2009 through the date of this filing.

Merger of TEPPCO and TEPPCO GP with Enterprise Products Partners

On October 26, 2009, the related mergers of our wholly owned subsidiaries with TEPPCO and TEPPGO GP were completed. Under terms of the merger agreements, TEPPCO and TEPPCO GP became wholly owned subsidiaries of ours and each of TEPPCO's unitholders, except for a privately held affiliate of EPCO, were entitled to receive 1.24 of our common units for each TEPPCO unit. In total, we issued an aggregate of 126,932,318 common units and 4,520,431 Class B units (described below) as consideration in the TEPPCO Merger for both TEPPCO units and the TEPPCO GP membership interests. TEPPCO's units, which had been trading on the NYSE under the ticker symbol TPP, have been delisted and are no longer publicly traded.

A privately held affiliate of EPCO exchanged a portion of its TEPPCO units, based on the 1.24 exchange rate, for 4,520,431 of our Class B units in lieu of common units. The Class B units are not entitled to regular quarterly cash distributions for the first sixteen quarters following the closing date of the merger. The Class B units automatically convert into the same number of common units on the date immediately following the payment date for the sixteenth quarterly distribution following the closing date of the merger. The Class B units are entitled to vote together with the common units as a single class on partnership matters and, except for the payment of distributions, have the same rights and privileges as our common units.

Under the terms of the TEPPCO Merger agreements, Enterprise GP Holdings received 1,331,681 of our common units and an increase in the capital account of EPGP to maintain its 2% general partner interest in us as consideration for 100% of the membership interests of TEPPCO GP. Following the closing of the TEPPCO Merger, affiliates of EPCO owned approximately 31.3% of our outstanding limited partner units, including 3.4% owned by Enterprise GP Holdings.

The post-merger partnership, which retains the name Enterprise Products Partners L.P., accesses the largest producing basins of natural gas, NGLs and crude oil in the U.S., and serves some of the largest consuming regions for natural gas, NGLs, refined products, crude oil and petrochemicals. The post-merger partnership owns almost 48,000 miles of pipelines comprised of over 22,000 miles of NGL, refined product and petrochemical pipelines, over 20,000 miles of natural gas pipelines and more than 5,000 miles of crude oil pipelines. The merged partnership's logistical assets include approximately 200 MMBbls of NGL, refined product and crude oil storage capacity; 27 Bcf of natural gas storage capacity; one of the largest NGL import/export terminals in the U.S., located on the Houston Ship Channel; 60 NGL, refined product and chemical terminals spanning the U.S. from the west coast to the east coast; and crude oil import terminals on the Texas Gulf Coast. The post-merger partnership owns interests in 17 fractionation plants with over 600 MBPD of net capacity; 25 natural gas processing plants with a net capacity of approximately

9 Bcf/d; and 3 butane isomerization facilities with a capacity of 116 MBPD. The post-merger partnership is also one of the largest inland tank barge companies in the U.S.

The merger transactions will be accounted for as a reorganization of entities under common control in a manner similar to a pooling of interests. The financial and operating activities of Enterprise Products Partners, TEPPCO and Enterprise GP Holdings and their respective general partners, and EPCO and its privately held subsidiaries, are under the common control of Dan L. Duncan. See Note 18 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report for selected financial information, including selected unaudited pro forma data, related to the merger.

In connection with the TEPPCO Merger, EPO commenced offers in September 2009 to exchange all of TEPPCO's outstanding notes (a combined principal amount of $2 billion) for a corresponding series of new EPO notes. The purpose of the exchange offer was to simplify our capital structure following the TEPPCO Merger. The exchanges were completed on October 27, 2009. The new EPO notes are guaranteed by Enterprise Products Partners L.P. The EPO notes issued in the exchange will be recorded at the same carrying value as the TEPPCO notes being replaced. Accordingly, we will recognize no gain or loss for accounting purposes related to this exchange. All note exchange direct costs paid to third parties will be expensed. In addition to the debt exchange, we gained approval from the requisite TEPPCO noteholders to eliminate substantially all of the restrictive covenants and reporting requirements associated with the remaining TEPPCO notes. Upon the consummation of the TEPPCO Merger, EPO repaid and terminated indebtedness under TEPPCO's revolving credit facility.

Enterprise Products Partners and Duncan Energy Partners Announce Extension of Acadian Gas System into Haynesville Shale Play

In October 2009, we and our affiliate, Duncan Energy Partners, announced plans for our jointly owned Acadian Gas System to extend its Louisiana intrastate natural gas pipeline system into Northwest Louisiana to provide producers in the rapidly expanding Haynesville Shale resource basin with access to additional markets through connections with the Acadian Gas System in South Louisiana and nine major interstate natural gas pipelines ("Haynesville Extension"). The Haynesville Shale covers about 2 million acres in Northwest Louisiana, almost all of which is under lease. Production from the approximately 200 wells drilled to date is estimated at more than 1 Bcf/d. Over 400 locations are in various stages of drilling and completion with approximately 150 rigs now working in the region.

As currently designed, our Haynesville Extension pipeline project will have the capacity to transport up to 1.4 Bcf/d of natural gas from the Haynesville area through a 249-mile pipeline that will connect with our existing Acadian Gas System. Subject to additional long-term commitments received before pipe orders are placed, the capacity of the Haynesville Extension could be increased to 2.0 Bcf/d. The pipeline is expected to be in service in September 2011.

The Acadian Gas System serves major natural gas markets along the Mississippi River corridor between Baton Rouge and New Orleans and has the ability to make physical deliveries into the Henry Hub. The Haynesville Extension will also have interconnects with major interstate pipelines include Florida Gas, Texas Eastern, Transco, Sonat, Columbia Gulf, Trunkline, ANR, Tennessee Gas and Texas Gas. Together with the capacity of the existing Acadian Gas System, the extension project will provide approximately 5.5 Bcf/d of redelivery capacity into an estimated 12 Bcf/d of available downstream pipeline takeaway capacity. Initially, the project will connect to nine Haynesville Shale producer locations in DeSoto and Red River parishes.

Along with providing much needed natural gas takeaway capacity for growing Haynesville production, the new pipeline is expected to provide shippers the opportunity to benefit from more favorable pricing points and diverse service options and access to the South Louisiana marketplace. For producers, the more flexible contracting options associated with an intrastate pipeline environment would help facilitate a seamless transaction for the producer from the field to the end user.

Currently, Duncan Energy Partners owns a 66% equity interest in the entities that own the Acadian Gas System, with EPO owning the remaining 34% equity interests. Duncan Energy Partners and EPO are in discussions as to the funding of the Haynesville Extension project.

EPO Issues $1.1 Billion of Senior Notes

In October 2009, EPO issued $500.0 million in principal amount of 5.25% fixed-rate, unsecured senior notes due January 2020 ("Senior Notes Q") and $600.0 million in principal amount of 6.125% fixed-rate, unsecured senior notes due October 2039 ("Senior Notes R"). Net proceeds from this offering were used (i) to repay $500.0 million in aggregate principal amount of senior notes that matured in October 2009 ("Senior Notes F"), (ii) to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and (iii) for general partnership purposes. For additional information regarding these issuances of debt, see Note 18 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report.

Enterprise Products Partners Issues $226.4 million of Common Units

In September 2009, we issued 8,337,500 common units (including an overallotment amount of 1,087,500 common units) in an underwritten public offering at a price of $28.00 per unit. We used the combined net offering proceeds of $226.4 million to reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes.

Enterprise Products Partners to Provide Natural Gas Transportation and Processing Services for Major Eagle Ford Shale Producer

In September 2009, we announced that we had entered into a long-term agreement to provide natural gas transportation and processing services on dedicated acreage owned by one of the largest and most active producers in the developing Eagle Ford Shale natural gas play in South Texas. The agreement covers more than 150,000 acres in the heart of the Eagle Ford Shale natural gas play. Stretching from the Mexico border along the Gulf Coast to near Louisiana, the Eagle Ford Shale production area covers more than 10 million acres in Texas and lies beneath or near our existing natural gas and NGL asset infrastructure in the region.

Enterprise Products Partners Enters into Agreement for $150.0 Million Private Placement of Common Units

On September 4, 2009, we agreed to issue 5,940,594 common units in a private placement to EPCO Holdings, Inc., a privately held affiliate controlled by Dan L. Duncan, for approximately $150.0 million, or $25.25 per unit. In accordance with the terms of the private placement, as approved by the Audit, Conflicts and Governance Committee of EPGP's Board of Directors on September 1, 2009, the per unit purchase price of $25.25 was calculated based on a five percent discount to the five-day volume weighted average price ("5-Day VWAP") of our common units, as reported by the NYSE at the close of business on September 4, 2009. The 5-Day VWAP was based on (i) the closing price for the common units on the NYSE for each of the trading days in such five-day period and (ii) the total trading volume for the common units reported by the NYSE for each such trading day. We used the net proceeds from this private placement to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for other general partnership purposes. The common units were issued on September 8, 2009.

Enterprise Products Partners Announces Expansion of NGL Fractionation Capacity at Mont Belvieu, Texas Complex

In August 2009, we announced plans to build a new 75 MBPD NGL fractionator at our Mont Belvieu, Texas complex that will provide us with additional capacity to handle growing NGL volumes from producing areas in the Rockies, the Barnett Shale and the emerging Eagle Ford Shale play in South Texas. This expansion, which is supported by long-term contracts, will be based on the design of our 75 MBPD Hobbs fractionator in Gaines County, Texas that began service in August 2007. When completed, the project will increase our NGL fractionation capacity at Mont Belvieu to approximately 300 MBPD and net system-wide capacity to approximately 600 MBPD. The project is expected to be completed in the first quarter of 2011.

Duncan Energy Partners' Equity Offering

In June 2009, Duncan Energy Partners completed an offering of 8,000,000 of its common units, which generated net proceeds of approximately $122.9 million. In July 2009, the underwriters to this offering exercised their option to purchase an additional 943,400 common units, which generated $14.5 million of additional net proceeds for Duncan Energy Partners. Duncan Energy Partners used the aggregate net proceeds from this offering to repurchase an equal number of its common units that were beneficially owned by EPO. Duncan Energy Partners subsequently cancelled the common units it repurchased from EPO.

Jicarilla Apache Nation and Enterprise Products Partners Announce Long-Term Right-of-Way Agreement

In June 2009, the Jicarilla Apache Nation and an affiliate of ours announced they had signed a 20-year right-of-way agreement that will allow us to continue our natural gas gathering operations on the Nation's reservation lands in Northwest New Mexico. Under the terms of the agreement, we will continue to own and operate existing infrastructure and related assets located on tribal land, including 545 miles of gathering lines connected to our San Juan Gathering system that have current throughput in excess of 30 MMcf/d of natural gas.

EPO Issues $500.0 Million of Senior Notes

In June 2009, EPO issued $500.0 million in principal amount of 4.60% fixed-rate, unsecured senior notes due August 2012 ("Senior Notes P"). Net proceeds from this offering were used (i) to repay the $200.0 Million Term Loan, (ii) to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and (iii) for general partnership purposes. For additional information regarding this issuance of debt, see Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report.

Enterprise Products Partners Exits Texas Offshore Port System Partnership

In August 2008, a wholly owned subsidiary of ours, together with a subsidiary of TEPPCO and Oiltanking Holding Americas, Inc. ("Oiltanking"), formed the Texas Offshore Port System partnership ("TOPS"). Effective April 16, 2009, our wholly owned subsidiary dissociated (exited) from TOPS. As a result, equity earnings for the nine months ended September 30, 2009 reflects a non-cash charge of $34.2 million. This loss represented our cumulative investment in TOPS through the date of dissociation and reflected our capital contributions to TOPS for construction in progress amounts. The subsidiary of TEPPCO also dissociated from TOPS in April 2009. On September 17, 2009, we and TEPPCO entered into a settlement agreement with certain affiliates of Oiltanking that resolved all disputes between the parties related to the business and affairs of the TOPS project. We and TEPPCO each recognized approximately $33.5 million of expense during the third quarter of 2009 in connection with this settlement. See Note 14 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report for litigation matters associated with our dissociation from TOPS.

Service Begins on Shenzi Crude Oil Export Pipeline

In April 2009, we announced that construction of our crude oil pipeline serving the Shenzi field in the Gulf of Mexico had been completed and is now transporting production from the deepwater discovery. The 83-mile pipeline has a transportation capacity of 230 MBPD of crude oil and gives Shenzi producers access to the Cameron Highway Oil Pipeline and Poseidon Oil Pipeline systems, in which we have ownership interests and operate.

Service Begins on Sherman Extension Pipeline

In late February 2009, we and Duncan Energy Partners announced that construction had been completed on the 174-mile Sherman Extension expansion of our Texas Intrastate System, which extends through the heart of the prolific Barnett Shale natural gas play of North Texas. The completion of the Sherman Extension adds 1.1 Bcf/d of incremental natural gas takeaway capacity from the region, while providing producers in the Barnett Shale, and as far away as the Waha area of West Texas, with greater flexibility to reach the most attractive natural gas markets. The Texas Intrastate System is part of our Onshore Natural Gas Pipelines & Services business segment.

Initially, the Sherman Extension was in very limited service due to pipeline integrity issues on the connecting third party take-away pipeline, the Gulf Crossing Pipeline owned by Boardwalk Pipeline Partners, LP ("Boardwalk"). The Gulf Crossing Pipeline began ramping up its operations on August 1, 2009. As a result, the Sherman Extension started billing its demand charges at 95% of contracted volumes, which are 950 MMcf/d. Effective September 1, 2009, the Sherman Extension started billing demand charges at 100% of contracted volumes irrespective of actual transportation volumes. We are currently flowing approximately 700 MMcf/d. The demand charges are approximately $5.0 million a month.

Review of Consolidated Results

We have four reportable business segments: NGL Pipelines & Services, Onshore Natural Gas Pipelines & Services, Offshore Pipelines & Services and Petrochemical Services. Our business segments are generally organized and managed according to the type of services rendered (or technologies employed) and products produced and/or sold. For additional information regarding our business segments, see Note 11 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report.

Selected Price and Volumetric Data

The following table illustrates selected annual and quarterly industry index prices for natural gas, crude oil and selected NGL and petrochemical products for the periods presented:

	Natural Gas, $/MMBtus	Crude Oil, $/barrel	Ethane, $/gallon	Propane, $/gallon	Normal Butane, $/gallon	Isobutane, $/gallon	Natural Gasoline, $/gallon	Polymer Grade Propylene, $/pound	Refinery Grade Propylene, $/pound
	(1)	(2)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
2008									
1st Quarter	$8.03	$97.91	$1.01	$1.47	$1.80	$1.87	$2.12	$0.61	$0.54
2nd Quarter	$10.94	$123.88	$1.05	$1.70	$2.05	$2.08	$2.64	$0.70	$0.67
3rd Quarter	$10.25	$118.01	$1.09	$1.68	$1.97	$1.99	$2.52	$0.78	$0.66
4th Quarter	$6.95	$58.32	$0.42	$0.80	$0.90	$0.96	$1.09	$0.37	$0.22
2008 Averages	$9.04	$99.53	$0.89	$1.41	$1.68	$1.72	$2.09	$0.62	$0.52
2009									
1st Quarter	$4.91	$42.96	$0.36	$0.68	$0.87	$0.97	$0.96	$0.26	$0.20
2nd Quarter	$3.51	$59.54	$0.43	$0.73	$0.93	$1.11	$1.21	$0.34	$0.28
3rd Quarter	$3.39	$68.20	$0.47	$0.87	$1.12	$1.19	$1.42	$0.48	$0.43
2009 Averages	$3.93	$56.90	$0.42	$0.76	$0.97	$1.09	$1.20	$0.36	$0.30

(1) Natural gas, NGL, polymer grade propylene and refinery grade propylene prices represent an average of various commercial index prices including Oil Price Information Service ("OPIS") and Chemical Market Associates, Inc. ("CMAI"). Natural gas price is representative of Henry-Hub I-FERC. NGL prices are representative of Mont Belvieu Non-TET pricing. Refinery grade propylene represents a weighted-average of CMAI spot prices. Polymer-grade propylene represents average CMAI contract pricing.
(2) Crude oil price is representative of an index price for West Texas Intermediate.

The following table presents our material average throughput, production and processing volumetric data. These statistics are reported on a net basis, taking into account our ownership interests in certain joint ventures and reflect the periods in which we owned an interest in such operations. These statistics include volumes for newly constructed assets since the dates such assets were placed into service and for recently purchased assets since the date of acquisition.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
NGL Pipelines & Services, net:				
NGL transportation volumes (MBPD)	1,981	1,758	1,905	1,788
NGL fractionation volumes (MBPD)	453	413	444	424
Equity NGL production (MBPD)	116	109	116	108
Fee-based natural gas processing (MMcf/d)	2,247	2,064	2,685	2,469
Onshore Natural Gas Pipelines & Services, net:				
Natural gas transportation volumes (BBtus/d)	8,207	7,562	8,149	7,313
Offshore Pipelines & Services, net:				
Natural gas transportation volumes (BBtus/d)	1,374	1,244	1,458	1,449
Crude oil transportation volumes (MBPD)	369	147	278	190
Platform natural gas processing (MMcf/d)	694	583	741	588
Platform crude oil processing (MBPD)	17	14	10	19
Petrochemical Services, net:				
Butane isomerization volumes (MBPD)	104	71	98	85
Propylene fractionation volumes (MBPD)	67	58	67	67
Octane additive production volumes (MBPD)	13	8	9	9
Petrochemical transportation volumes (MBPD)	125	95	114	110
Total, net:				
NGL, crude oil and petrochemical transportation volumes (MBPD)	2,475	2,000	2,297	2,088
Natural gas transportation volumes (BBtus/d)	9,581	8,806	9,607	8,762
Equivalent transportation volumes (MBPD) (1)	4,996	4,317	4,825	4,394

(1) Reflects equivalent energy volumes where 3.8 MMBtus of natural gas are equivalent to one barrel of NGLs.

Comparison of Consolidated Results of Operations

The following table summarizes the key components of our consolidated income statement for the periods indicated (dollars in millions):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Revenues	$ 4,596.1	$ 6,297.9	$ 11,527.1	$ 18,322.1
Operating costs and expenses	4,220.2	5,971.9	10,395.7	17,243.1
General and administrative costs	33.9	21.8	84.7	67.0
Equity in income of unconsolidated affiliates	22.5	14.9	18.3	48.1
Operating income	364.5	319.1	1,065.0	1,060.1
Interest expense	128.0	102.7	374.6	290.4
Provision for income taxes	6.6	6.6	24.0	17.2
Net income	229.9	211.0	667.3	755.3
Net income attributable to noncontrolling interest	17.0	7.9	42.5	29.3
Net income attributable to Enterprise Products Partners L.P.	212.9	203.1	624.8	726.0

Effective January 1, 2009, we adopted new accounting guidance that has been codified under ASC 810, which established accounting and reporting standards for noncontrolling interests, which were previously identified as minority interest in our financial statements. The new guidance requires, among other things, that (i) noncontrolling interests be presented as a component of equity on our consolidated balance sheet (i.e., elimination of the “mezzanine” presentation previously used for minority interest); (ii) minority interest amounts be eliminated as a deduction in deriving net income or loss and, as a result, that net income or loss be allocated between controlling and noncontrolling interests; and (iii) comprehensive income or loss to be allocated between controlling and noncontrolling interest. Earnings per unit amounts are not affected by these changes. See Note 2 of the Notes to Unaudited Condensed Consolidated Financial

Statements included under Item 1 of this Quarterly Report for additional information regarding the establishment of the ASC by the Financial Accounting Standards Board ("FASB"). See Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report for additional information regarding noncontrolling interest.

The new presentation and disclosure requirements pertaining to noncontrolling interests have been applied retroactively to the consolidated financial statements and notes included in this Quarterly Report. As a result, net income reported for the three and nine months ended September 30, 2008 in these financial statements is higher than that disclosed previously; however, the allocation of such net income results in our unitholders, general partner and noncontrolling interests (i.e., the former minority interest) receiving the same amounts as they did previously.

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income. Our non-GAAP financial measure of total segment gross operating margin should not be considered as an alternative to GAAP operating income.

Our consolidated gross operating margin amounts include the gross operating margin amounts of Duncan Energy Partners on a 100% basis. Volumetric data associated with the operations of Duncan Energy Partners are also included on a 100% basis in our consolidated statistical data.

Our gross operating margin by segment and in total is as follows for the periods indicated (dollars in millions):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Gross operating margin by segment:				
NGL Pipelines & Services	$ 392.0	$ 336.1	$ 1,088.8	$ 943.5
Onshore Natural Gas Pipelines & Services	62.3	88.1	252.6	321.2
Offshore Pipeline & Services	56.3	17.5	150.7	134.4
Petrochemical Services	50.3	37.2	126.7	136.4
Total segment gross operating margin	$ 560.9	$ 478.9	$ 1,618.8	$ 1,535.5

For a reconciliation of non-GAAP gross operating margin to GAAP operating income and income before provision for income taxes, see "Other Items – Non-GAAP Reconciliations" included within this Item 2.

The following table summarizes the contribution to revenues from each business segment (including the effects of eliminations and adjustments) during the periods indicated (dollars in millions):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
NGL Pipelines & Services:				
Sales of NGLs	$ 3,054.9	$ 4,257.8	$ 7,623.0	$ 12,514.6
Sales of other petroleum and related products	0.6	0.5	1.5	1.9
Midstream services	160.4	170.7	448.5	528.9
Total	3,215.9	4,429.0	8,073.0	13,045.4
Onshore Natural Gas Pipelines & Services:				
Sales of natural gas	585.7	859.2	1,645.3	2,400.4
Midstream services	113.3	118.6	326.6	370.5
Total	699.0	977.8	1,971.9	2,770.9
Offshore Pipelines & Services:				
Sales of natural gas	0.3	0.9	0.9	2.5
Sales of other petroleum and related products	2.0	3.7	3.1	10.8
Midstream services	99.4	60.4	243.5	191.9
Total	101.7	65.0	247.5	205.2
Petrochemical Services:				
Sales of other petroleum and related products	558.8	803.4	1,165.3	2,233.7
Midstream services	20.7	22.7	69.4	66.9
Total	579.5	826.1	1,234.7	2,300.6
Total consolidated revenues	$ 4,596.1	$ 6,297.9	$ 11,527.1	$ 18,322.1

Comparison of Three Months Ended September 30, 2009 with Three Months Ended September 30, 2008

Revenues for the third quarter of 2009 were $4.60 billion compared to $6.30 billion for the third quarter of 2008. The $1.70 billion quarter-to-quarter decrease in consolidated revenues is primarily due to lower energy commodity sales prices associated with our NGL, natural gas and petrochemical marketing activities during the third quarter of 2009 relative to the third quarter of 2008. Consolidated revenues for the third quarter of 2009 include $19.2 million of cash proceeds from business interruption insurance due to the effects of Hurricane Ike on our operations.

Operating costs and expenses were $4.22 billion for the third quarter of 2009 versus $5.97 billion for the third quarter of 2008, a $1.75 billion quarter-to-quarter decrease. The cost of sales of our marketing activities decreased $1.46 billion quarter-to-quarter primarily due to lower energy commodity prices. Likewise, the operating costs and expenses of our natural gas processing plants decreased $315.1 million quarter-to-quarter primarily due to lower plant thermal reduction (i.e., PTR) costs attributable to the decline in energy commodity prices. Consolidated operating costs and expenses for the third quarter of 2009 include $33.5 million of expenses related to the settlement of litigation involving TOPS. General and administrative costs increased $12.1 million quarter-to-quarter primarily due to expenses we incurred during the third quarter of 2009 related to the TEPPCO Merger.

Changes in our revenues and costs and expenses quarter-to-quarter are primarily explained by fluctuations in energy commodity prices. The weighted-average indicative market price for NGLs was $0.88 per gallon during the third quarter of 2009 versus $1.68 per gallon during the third quarter of 2008 – a 48% decrease quarter-to-quarter. Our determination of the weighted-average indicative market price for NGLs is based on U.S. Gulf Coast prices for such products at Mont Belvieu, Texas, which is the primary industry hub for domestic NGL production. The market price of natural gas (as measured at Henry Hub in Louisiana) decreased 67% quarter-to-quarter to an average of $3.39 per MMBtus during the third quarter of 2009 versus $10.25 per MMBtus during the third quarter of 2008. See "Results of Operations - Selected Price and Volumetric Data" within this Item 2 for additional historical energy commodity pricing information.

Equity in income from our unconsolidated affiliates was $22.5 million for the third quarter of 2009 compared to $14.9 million for the third quarter of 2008, a $7.6 million quarter-to-quarter increase. Collectively, equity in income from our investments in Cameron Highway Oil Pipeline Company ("Cameron Highway") and Poseidon Oil Pipeline, L.L.C. ("Poseidon") increased $8.7 million quarter-to-quarter due to higher transportation volumes during the third quarter of 2009 relative to the third quarter of 2008. Our investments in White River Hub, LLC ("White River Hub") and Skelly-Belvieu Pipeline Company, L.L.C. ("Skelly-Belvieu") contributed equity in income of $0.9 million and $0.3 million, respectively, for the third quarter of 2009. The assets owned by White River Hub began commercial operations in December 2008. We acquired a 49% equity interest in Skelly-Belvieu during December 2008. Equity in income decreased $3.2 million quarter-to-quarter from our Marco Polo platform due to the expiration of demand fee revenues during March 2009. The Marco Polo platform is owned through our investment in Deepwater Gateway, L.L.C. ("Deepwater Gateway"). Collectively, equity in income from our other equity investments increased $1.0 million quarter-to-quarter.

Operating income for the third quarter of 2009 was $364.5 million compared to $319.1 million for the third quarter of 2008. Consolidated revenues and certain operating costs and expenses (e.g., cost of sales amounts) can fluctuate significantly due to changes in energy commodity prices without necessarily affecting our operating income to the same degree. Consequently, the aforementioned changes in revenues, costs and expenses and equity in income of unconsolidated affiliates contributed to the $45.4 million quarter-to-quarter increase in operating income.

Interest expense increased to $128.0 million for the third quarter of 2009 from $102.7 million for the third quarter of 2008. The $25.3 million quarter-to-quarter increase in interest expense is primarily due to our issuance of Senior Notes O in the fourth quarter of 2008, Senior Notes P in the second quarter of 2009 and a $10.7 million decrease in capitalized interest during the third quarter of 2009 relative to the third quarter of 2008. Average debt principal outstanding increased during the third quarter of 2009 to $9.44 billion from $8.14 billion during the third quarter of 2008 primarily due to debt incurred to fund growth capital projects.

As a result of items noted in the previous paragraphs, net income increased $18.9 million quarter-to-quarter to $229.9 million for the third quarter of 2009 compared to $211.0 million for the third quarter of 2008. Net income attributable to noncontrolling interests was $17.0 million for the third quarter of 2009 compared to $7.9 million for the third quarter of 2008. Net income attributable to Enterprise Products Partners increased $9.8 million quarter-to-quarter to $212.9 million for the third quarter of 2009 compared to $203.1 million for the third quarter of 2008.

In general, Hurricanes Gustav and Ike had an adverse effect on our operations in the Gulf of Mexico and onshore along the U.S. Gulf Coast during the third quarter of 2008. Storm-related disruptions in natural gas, NGL and crude oil production in these regions resulted in reduced volumes available to our pipeline systems, natural gas processing plants, NGL fractionators and offshore platforms, which in turn caused a decrease in gross operating margin for certain operations. In addition, property damage caused by these hurricanes resulted in lower revenues due to facility downtime as well as higher operating costs and expenses at certain of our plants and pipelines. As a result of insurance deductibles for windstorm damage, gross operating margin for the third quarter of 2008 includes $46.0 million of repair expenses for property damage sustained by our assets as a result of Hurricanes Gustav and Ike. Gross operating margin for the third quarter of 2009 includes $19.2 million of proceeds from business interruption insurance due to the effects of Hurricane Ike on our operations. For more information regarding our insurance program and claims related to these storms, see "Other Items – Insurance Matters" included within this Item 2.

The following information highlights significant quarter-to-quarter variances in gross operating margin by business segment:

NGL Pipelines & Services. Gross operating margin from this business segment was $392.0 million for the third quarter of 2009 compared to $336.1 million for the third quarter of 2008, a $55.9 million quarter-to-quarter increase. In general, this business segment benefited from a quarter-to-quarter increase in NGL transportation and fractionation volumes, improved results from our NGL marketing activities and lower fuel costs during the third quarter of 2009 compared to the third quarter of 2008. The third quarter of 2009 includes $1.2 million of cash proceeds from business interruption insurance claims. The following paragraphs provide a discussion of segment results excluding cash proceeds from business interruption insurance claims.

Gross operating margin from our natural gas processing and related NGL marketing business was $238.0 million for the third quarter of 2009 compared to $237.6 million for the third quarter of 2008. Equity NGL production increased to 116 MBPD during the third quarter of 2009 from 109 MBPD during the third quarter of 2008. Gross operating margin from our NGL marketing activities increased $16.5 million quarter-to-quarter due to higher NGL sales margins and volumes during the third quarter of 2009 relative to the third quarter of 2008. Gross operating margin from our South Louisiana natural gas processing plants increased $8.1 million quarter-to-quarter. These facilities were negatively impacted by downtime and property damage repair expenses caused by Hurricanes Gustav and Ike during the third quarter of 2008. Collectively, gross operating margin from the remainder of our natural gas processing plants decreased $24.2 million quarter-to-quarter primarily due to lower processing margins in South Texas, the Permian Basin and Rocky Mountains.

Gross operating margin from our NGL pipelines and related storage business was $121.7 million for the third quarter of 2009 compared to $72.6 million for the third quarter of 2008, a $49.1 million quarter-to-quarter increase. Gross operating margin from our Mid-America and Seminole pipeline systems increased $24.9 million quarter-to-quarter due to higher volumes and lower fuel costs. Collectively, gross operating margin from the remainder of our NGL pipelines, export dock and storage assets increased $24.2 million quarter-to-quarter largely due to increased storage volumes and fees at our Mont Belvieu storage complex, improved results from our assets in South Louisiana and lower fuel costs during the third quarter of 2009. Total NGL transportation volumes increased to 1,981 MBPD during the third quarter of 2009 from 1,758 MBPD during the third quarter of 2008.

Gross operating margin from our NGL fractionation business was $31.1 million for the third quarter of 2009 compared to $25.9 million for the third quarter of 2008. Fractionation volumes increased to 453 MBPD during the third quarter of 2009 from 413 MBPD during the third quarter of 2008. The $5.2 million quarter-to-quarter increase in gross operating margin from this business is primarily due to increased fractionation volumes at our Mont Belvieu, Norco and Promix fractionators and lower fuel costs during the third quarter of 2009 relative to the third quarter of 2008.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $62.3 million for the third quarter of 2009 compared to $88.1 million for the third quarter of 2008, a $25.8 million quarter-to-quarter decrease. Our onshore natural gas transportation volumes were 8,207 BBtus/d during the third quarter of 2009 compared to 7,562 BBtus/d during the third quarter of 2008.

Gross operating margin from our onshore natural gas pipelines and related natural gas marketing business was $48.8 million for the third quarter of 2009 compared to $77.4 million for the third quarter of 2008, a $28.6 million quarter-to-quarter decrease. The Sherman Extension pipeline segment of our Texas Intrastate System began commercial operations on August 1, 2009 and contributed $9.0 million of gross operating margin during the third quarter of 2009, primarily from firm capacity fee revenues. Gross operating margin from our San Juan gathering system decreased $27.0 million quarter-to-quarter primarily due to lower commodity prices, which resulted in reduced revenues earned from natural gas gathering contracts where fees are indexed to regional natural gas prices and lower condensate sales revenues. Collectively, gross operating margin from the remainder of the businesses classified within this segment decreased $10.6 million quarter-to-quarter largely due to a decrease in natural gas transportation volumes and condensate sales revenues, both of which relate primarily to our Texas operations, during the third quarter of 2009 compared to the third quarter of 2008.

Gross operating margin from our natural gas storage business was $13.5 million for the third quarter of 2009 compared to $10.7 million for the third quarter of 2008. The $2.8 million quarter-to-quarter increase in gross operating margin is primarily due to increased storage activity at our Petal and Wilson natural gas storage facilities.

Offshore Pipelines & Services. Gross operating margin from this business segment was $56.3 million for the third quarter of 2009 compared to $17.5 million for the third quarter of 2008. Results from this business segment for the third quarter of 2009 include $18.0 million of cash proceeds from business interruption insurance claims and $33.5 million of expenses for the TOPS litigation settlement. Results for the third quarter of 2008 were negatively impacted by downtime, reduced volumes and $35.5 million of property damage repair expenses resulting from Hurricanes Gustav and Ike. The following paragraphs provide a discussion of segment results excluding the effect of cash proceeds from business interruption insurance claims.

Gross operating margin from our offshore natural gas pipeline business was $8.7 million for the third quarter of 2009 compared to a loss of $22.8 million for the third quarter of 2008. The $31.5 million quarter-to-quarter increase in gross operating margin is primarily due to the impact of Hurricanes Gustav and Ike on this business during the third quarter of 2008, which includes $32.1 million of hurricane-related property damage repair expenses. Gross operating margin from our Independence Trail pipeline increased $6.3 million quarter-to-quarter due to higher transportation volumes. Collectively, gross operating margin from our other offshore natural gas pipelines decreased $6.9 million quarter-to-quarter primarily due to higher maintenance and repair expenses during the third quarter of 2009 associated with our Anaconda and HIOS pipeline systems. Offshore natural gas transportation volumes were 1,374 BBtus/d during the third quarter of 2009 compared to 1,244 BBtus/d during the third quarter of 2008.

Gross operating margin from our offshore crude oil pipeline business was a loss of $5.6 million for the third quarter of 2009 compared to earnings of $5.7 million for the third quarter of 2008, an $11.3 million quarter-to-quarter decrease. Excluding the $33.5 million of expenses we recorded during the third quarter of 2009 as a result of the TOPS litigation settlement, gross operating margin from this business increased $22.2 million quarter-to-quarter.

We completed the Shenzi crude oil pipeline and began commercial operation during April 2009. Collectively, gross operating margin from our crude oil pipelines increased $22.2 million quarter-to-quarter primarily due to the start-up of our Shenzi crude oil pipeline and higher transportation volumes on Cameron Highway and Poseidon crude oil pipelines, which were both impacted by last year's hurricanes. Offshore crude oil transportation volumes were 369 MBPD during the third quarter of 2009 versus 147 MBPD during the third quarter of 2008.

Gross operating margin from our offshore platform services business was $35.2 million for the third quarter of 2009 compared to $34.6 million for the third quarter of 2008, a $0.6 million quarter-to-quarter increase. Gross operating margin from our Independence Hub platform increased $3.1 million quarter-to-quarter due to higher natural gas processing volumes during the third quarter of 2009 relative to the third quarter of 2008. Collectively, gross operating margin from our other offshore platforms decreased $2.5 million quarter-to-quarter primarily due to the expiration of demand fee revenues at our Marco Polo platform in March 2009. Our net platform natural gas processing volumes increased to 694 MMcf/d during the third quarter of 2009 from 583 MMcf/d during the third quarter of 2008. Our net platform crude oil processing volumes increased to 17 MBPD during the third quarter of 2009 compared to 14 MBPD during the third quarter of 2008.

Petrochemical Services. Gross operating margin from this business segment was $50.3 million for the third quarter of 2009 compared to $37.2 million for the third quarter of 2008. Gross operating margin from our octane enhancement business was $5.2 million for the third quarter of 2009 compared to a loss of $12.9 million for the third quarter of 2008. The $18.1 million quarter-to-quarter increase in gross operating margin is due to higher volumes and lower operating expenses in the third quarter of 2009 compared to the third quarter of 2008. During the third quarter of 2008, in addition to downtime associated with Hurricane Ike, the octane enhancement facility had operational issues that resulted in higher operating expenses, downtime and decreased production volumes. Octane enhancement production volumes increased to 13 MBPD during the third quarter of 2009 from 8 MBPD during the third quarter of 2008.

Gross operating margin from our propylene fractionation and pipeline business was $22.6 million for the third quarter of 2009 compared to $31.0 million for the third quarter of 2008. The $8.4 million quarter-to-quarter decrease in gross operating margin is due to lower propylene sales margins, which more than offset the benefit of increased propylene fractionation volumes. Propylene fractionation volumes increased to 67 MBPD during the third quarter of 2009 from 58 MBPD during the third quarter of 2008. Gross operating margin from our butane isomerization business was $22.5 million for the third quarter of 2009 compared to $19.1 million for the third quarter of 2008. The $3.4 million quarter-to-quarter increase in gross operating margin from this business is attributable to increased isomerization volumes, partially offset by lower by-product revenues. Butane isomerization volumes increased to 104 MBPD during the third quarter of 2009 from 71 MBPD during the third quarter of 2008.

Comparison of Nine Months Ended September 30, 2009 with Nine Months Ended September 30, 2008

Revenues for the first nine months of 2009 were $11.53 billion compared to $18.32 billion for the first nine months of 2008. The $6.79 billion period-to-period decrease in consolidated revenues is primarily due to lower energy commodity sales prices associated with our NGL, natural gas and petrochemical marketing activities during the first nine months of 2009 compared to the first nine months of 2008.

Operating costs and expenses were $10.40 billion for the first nine months of 2009 compared to $17.24 billion for the first nine months of 2008, a $6.84 billion period-to-period decrease. The cost of sales of our marketing activities decreased $5.78 billion period-to-period primarily due to lower energy commodity prices. Likewise, the operating costs and expenses of our natural gas processing plants decreased $979.7 million period-to-period primarily due to lower PTR costs attributable to the decline in energy commodity prices. Consolidated operating costs and expenses for the first nine months of 2009 include $33.5 million of expenses related to the settlement of litigation involving TOPS. General and administrative costs increased $17.7 million period-to-period primarily due to expenses we incurred during the first nine months of 2009 in connection with the TEPPCO Merger.

Changes in our revenues and costs and expenses period-to-period are primarily explained by fluctuations in energy commodity prices. The weighted-average indicative market price for NGLs was $0.77 per gallon during the first nine months of 2009 versus $1.62 per gallon during the first nine months of 2008 – a 52% decrease period-to-period. The Henry Hub market price of natural gas decreased 60% period-to-period to an average of $3.93 per MMBtus during the first nine months of 2009 versus $9.74 per MMBtus during the first nine months of 2008.

Equity in income from our unconsolidated affiliates was $18.3 million for the first nine months of 2009 compared to $48.1 million for the first nine months of 2008, a $29.8 million period-to-period decrease. Equity in income of unconsolidated affiliates for the first nine months of 2009 includes a $34.2 million non-cash charge to record the forfeiture of our investment in TOPS. Our investments in White River Hub and Skelly-Belvieu contributed equity in income of $2.9 million and $1.4 million, respectively, for the first nine months of 2009. Collectively, equity in loss of unconsolidated affiliates from our other equity investments increased $0.2 million period-to-period.

Operating income for the first nine months of 2009 was $1.07 billion compared to $1.06 billion for the first nine months of 2008. Consolidated revenues and certain operating costs and expenses can fluctuate significantly due to changes in energy commodity prices without necessarily affecting our operating income to the same degree. Consequently, the aforementioned changes in revenues, costs and expenses and equity in income of unconsolidated affiliates contributed to the $4.9 million period-to-period increase in operating income.

Interest expense increased to $374.6 million for the first nine months of 2009 from $290.4 million for the first nine months of 2008. The $84.2 million period-to-period increase in interest expense is primarily due to our issuance of Senior Notes M and N in the second quarter of 2008, Senior Notes O in the fourth quarter of 2008 and a $28.7 million decrease in capitalized interest during the first nine months of

2009 relative to the first nine months of 2008. Average debt principal outstanding increased during the first nine months of 2009 to $9.34 billion from $7.65 billion during the first nine months of 2008 primarily due to debt incurred to fund growth capital investments. Provision for income taxes increased $6.8 million period-to-period primarily due to a one-time charge of $6.6 million associated with taxable gains arising from Dixie Pipeline Company's ("Dixie") sale of certain assets during the first nine months of 2009.

As a result of items noted in the previous paragraphs, net income decreased $88.0 million period-to-period to $667.3 million for the first nine months of 2009 compared to $755.3 million for the first nine months of 2008. Net income attributable to noncontrolling interests was $42.5 million for 2009 compared to $29.3 million for 2008. Net income attributable to Enterprise Products Partners decreased $101.2 million period-to-period to $624.8 million for the first nine months of 2009 compared to $726.0 million for the first nine months of 2008.

The following information highlights significant period-to-period variances in gross operating margin by business segment:

NGL Pipelines & Services. Gross operating margin from this business segment was $1.09 billion for the first nine months of 2009 compared to $943.4 million for the first nine months of 2008, a $145.3 million period-to-period increase. In general, this business segment benefited from a period-to-period increase in gross operating margin from our recently constructed Rocky Mountain natural gas processing plants and related hedging program, improved results from our NGL marketing activities and lower fuel costs during the first nine months of 2009 compared to the first nine months of 2008. The first nine months of 2009 include $1.2 million of proceeds from business interruption insurance claims compared to $1.1 million of proceeds during the first nine months of 2008. The following paragraphs provide a discussion of segment results excluding the effect of cash proceeds from business interruption insurance.

Gross operating margin from our natural gas processing and related NGL marketing business was $652.0 million for the first nine months of 2009 compared to $611.8 million for the first nine months of 2008. Equity NGL production increased to 116 MBPD during the first nine months of 2009 from 108 MBPD during the first nine months of 2008. The $40.2 million period-to-period increase in gross operating margin from this business is attributable to our Rocky Mountain natural gas processing facilities and related hedging program and our NGL marketing activities, which benefited from higher sales margins and increased equity NGL production.

Gross operating margin from our NGL pipelines and related storage business was $339.4 million for the first nine months of 2009 compared to $252.8 million for the first nine months of 2008, an $86.6 million period-to-period increase. Total NGL transportation volumes increased to 1,905 MBPD during the first nine months of 2009 from 1,788 MBPD during the first nine months of 2008. Gross operating margin from our Mid-America and Seminole Pipeline Systems increased $33.6 million period-to-period due to increased volumes and lower fuel costs. Gross operating margin from our Mont Belvieu storage complex increased $13.4 million period-to-period primarily due to higher volumes and fees. Collectively, gross operating margin from the remainder of our NGL pipelines, export dock and related storage assets increased $39.6 million period-to-period largely due to lower fuel costs and higher volumes and fees at certain of our South Louisiana assets during the first nine months of 2009 relative to the first nine months of 2008.

Gross operating margin from our NGL fractionation business was $96.2 million for the first nine months of 2009 compared to $77.7 million for the first nine months of 2008. Fractionation volumes increased to 444 MBPD during the first nine months of 2009 from 424 MBPD during the first nine months of 2008. Gross operating margin from this business increased $18.5 million period-to-period largely due to higher NGL fractionation volumes at our Mont Belvieu and Baton Rouge fractionators and lower fuel costs during the first nine months of 2009 relative to the first nine months of 2008.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $252.6 million for the first nine months of 2009 compared to $321.2 million for the first nine months of 2008, a $68.6 million period-to-period decrease. Our onshore natural gas transportation volumes were

8,149 BBtus/d during the first nine months of 2009 compared to 7,313 BBtus/d during the first nine months of 2008.

Gross operating margin from our onshore natural gas pipeline and related natural gas marketing business was $213.7 million for the first nine months of 2009 compared to $292.2 million for the first nine months of 2008, a $78.5 million period-to-period decrease. The Sherman Extension pipeline segment of our Texas Intrastate System began commercial operations on August 1, 2009 and contributed $9.0 million of gross operating margin during 2009, primarily from firm capacity fee revenues. Gross operating margin from our San Juan gathering system decreased $88.6 million period-to-period due to lower fees indexed to regional natural gas prices and condensate sales revenues as a result of the period-to-period decrease in commodity prices. Lower natural gas gathering volumes in the Permian Basin resulted in a $9.2 million period-to-period decrease in gross operating margin on our Carlsbad gathering system. Gross operating margin from our Acadian Gas System decreased $4.3 million period-to-period due to lower natural gas sales volumes and margins. Collectively, gross operating margin from the remainder of the businesses classified within this segment increased $14.6 million period-to-period attributable to increased natural gas sales volumes and improved asset utilization as a result of our natural gas marketing activities, partially offset by a decrease in condensate sales revenues.

Gross operating margin from our natural gas storage business was $38.9 million for the first nine months of 2009 compared to $29.0 million for the first nine months of 2008. The $9.9 million period-to-period increase in gross operating margin is primarily due to increased storage activity at our Petal and Wilson natural gas storage facilities.

Offshore Pipelines & Services. Gross operating margin from this business segment was $150.7 million for the first nine months of 2009 compared to $134.4 million for the first nine months of 2008, a $16.3 million period-to-period increase. Results for the first nine months of 2009 include $18.0 million of cash proceeds from business interruption insurance claims and $67.7 million of total charges associated with the settlement of TOPS-related litigation and the forfeiture of our investment in TOPS. Results for the first nine months of 2008 include $0.2 million of proceeds from business interruption insurance claims and $35.5 million of property damage repair expenses resulting from Hurricanes Gustav and Ike. Combined gross operating margin from our Independence Hub platform and Trail pipeline increased $55.1 million period-to-period reflecting downtime and repair expenses incurred during the first nine months of 2008. The following paragraphs provide a discussion of segment results excluding cash proceeds from business interruption insurance.

Gross operating margin from our offshore natural gas pipeline business was $43.1 million for the first nine months of 2009 compared to a loss of $8.3 million for the first nine months of 2008, a $51.4 million period-to-period increase. Offshore natural gas transportation volumes were 1,458 BBtus/d during the first nine months of 2009 versus 1,449 BBtus/d during the first nine months of 2008. Gross operating margin from our Independence Trail pipeline increased $37.4 million period-to-period. Collectively, gross operating margin from our other offshore natural gas pipelines increased $14.0 million period-to-period primarily due to hurricane-related property damage repair expenses recorded during the first nine months of 2008.

Gross operating margin from our offshore crude oil pipeline business was a loss of $20.3 million for the first nine months of 2009 compared to earnings of $32.7 million for the first nine months of 2008, a $53.0 million period-to-period decrease. Results for the first nine months of 2009 include total charges of $67.7 million associated with the settlement of TOPS-related litigation and the forfeiture of our investment in TOPS. In addition, gross operating margin decreased $3.3 million period-to-period primarily due to the lingering effects Hurricanes Gustav and Ike had on our assets during the first nine months of 2009. Gross operating margin from our offshore crude oil pipelines increased $18.0 million period-to-period due to higher transportation volumes on our Shenzi, Cameron Highway and Poseidon crude oil pipelines. Total offshore crude oil transportation volumes were 278 MBPD during the first nine months of 2009 versus 190 MBPD during the first nine months of 2008.

Gross operating margin from our offshore platform services business was $109.9 million for the first nine months of 2009 compared to $109.8 million for the first nine months of 2008, a $0.1 million period-to-period increase. Gross operating margin from our Independence Hub platform increased $17.7 million period-to-period. Collectively, gross operating margin from our other offshore platforms and related assets decreased $17.6 million period-to-period primarily due to lower natural gas and crude oil processing volumes at our Marco Polo platform as a result of continuing hurricane-related disruptions and the expiration of demand fee revenues at our Marco Polo and Falcon platforms. Our net platform natural gas processing volumes increased to 741 MMcf/d during the first nine months of 2009 compared to 588 MMcf/d during the first nine months of 2008. Our net platform crude oil processing volumes decreased to 10 MBPD during the first nine months of 2009 compared to 19 MBPD during the first nine months of 2008.

Petrochemical Services. Gross operating margin from this business segment was $126.7 million for the first nine months of 2009 compared to $136.4 million for the first nine months of 2008. Gross operating margin from our butane isomerization business was $56.5 million for the first nine months of 2009 compared to $77.9 million for the first nine months of 2008. The $21.4 million period-to-period decrease in gross operating margin from this business is primarily due to lower proceeds from the sale of plant by-products as a result of lower commodity prices. Butane isomerization volumes increased to 98 MBPD during the first nine months of 2009 from 85 MBPD during the first nine months of 2008.

Gross operating margin from our octane enhancement business was $4.1 million for the first nine months of 2009 compared to a loss of $5.8 million for the first nine months of 2008. The $9.9 million period-to-period increase in gross operating margin is due to lower operating expenses during the first nine months of 2009 compared to the first nine months of 2008. During the third quarter of 2008, in addition to downtime associated with Hurricane Ike, the octane enhancement facility had operational issues that resulted in higher operating expenses, downtime and decreased production volumes. Gross operating margin from our propylene fractionation and pipeline business was $66.1 million for the first nine months of 2009 compared to $64.3 million for the first nine months of 2008. The $1.8 million period-to-period increase in gross operating margin is largely due to higher propylene sales volumes during the first nine months of 2009 relative to the first nine months of 2008. Propylene fractionation volumes increased to 67 MBPD during the first nine months of 2009 from 59 MBPD during the first nine months of 2008.

Liquidity and Capital Resources

Our primary cash requirements, in addition to normal operating expenses and debt service, are for working capital, capital expenditures, business acquisitions and distributions to partners. We expect to fund our short-term needs for such items as operating expenses and sustaining capital expenditures with operating cash flows and revolving credit arrangements. Capital expenditures for long-term needs resulting from business expansion projects and acquisitions are expected to be funded by a variety of sources (either separately or in combination) including operating cash flows, borrowings under credit facilities, the issuance of additional equity and debt securities and proceeds from divestitures of ownership interests in assets to affiliates or third parties. We expect to fund cash distributions to partners primarily with operating cash flows. Our debt service requirements are expected to be funded by operating cash flows and/or refinancing arrangements.

At September 30, 2009, we had $73.8 million of unrestricted cash on hand and approximately $1.09 billion of available credit under EPO's Multi-Year Revolving Credit Facility. We had approximately $9.15 billion in principal outstanding under consolidated debt agreements at September 30, 2009. In total, our consolidated liquidity at September 30, 2009 was approximately $1.31 billion, which includes the available borrowing capacity of our consolidated subsidiaries such as Duncan Energy Partners.

Registration Statements

We have a universal shelf registration statement on file with the SEC that allows us to issue an unlimited amount of debt and equity securities for general partnership purposes. In January 2009, we issued 10,590,000 common units (including an over-allotment of 990,000 common units) to the public at an offering price of $22.20 per unit under this registration statement. We used the net proceeds of $225.6 million from the January 2009 equity offering to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes. In June 2009, EPO issued $500.0 million in principal amount of Senior Notes P under this registration statement. Net proceeds from this senior note offering were used to repay the $200.0 Million Term Loan, to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes.

In September 2009, we issued 8,337,500 common units (including an over-allotment of 1,087,500 common units) to the public at an offering price of $28.00 per unit under this registration statement. We used the net proceeds of $226.4 million from the September 2009 equity offering to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes. In October 2009, EPO issued $1.1 billion in principal amount of Senior Notes Q and R under this registration statement. Net proceeds from this senior note offering were used to repay $500.0 million in aggregate principal amount of Senior Notes F that matured in October 2009, to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes.

We also have a registration statement on file with the SEC authorizing the issuance of up to 40,000,000 common units in connection with our distribution reinvestment plan ("DRIP"). During the nine months ended September 30, 2009, we issued 10,731,084 common units in connection with our DRIP, which generated proceeds of $254.7 million from plan participants. Affiliates of EPCO reinvested $226.5 million in connection with the DRIP during the nine months ended September 30, 2009.

In addition, we have a registration statement on file related to our employee unit purchase plan ("EUPP"), under which we can issue up to 1,200,000 common units. During the nine months ended September 30, 2009, we issued 141,512 common units to employees under this plan, which generated proceeds of $3.5 million.

Duncan Energy Partners has a universal shelf registration statement filed with the SEC that allows it to issue up to $1 billion of debt and equity securities. In June 2009, Duncan Energy Partners completed an offering of 8,000,000 of its common units, which generated net proceeds of approximately $122.9 million. In July 2009, the underwriters to this offering exercised their option to purchase an additional 943,400 common units, which generated approximately $14.5 million of additional net proceeds for Duncan Energy Partners. Duncan Energy Partners used the aggregate net proceeds from this offering to repurchase an equal number of its common units that were beneficially owned by EPO. Duncan Energy Partners subsequently cancelled the common units it repurchased from EPO. At September 30, 2009, Duncan Energy Partners can issue approximately $856.4 million of additional securities under its registration statement.

For information regarding our public debt obligations or partnership equity, see Notes 9 and 10, respectively, of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report.

Letter of Credit Facilities

At September 30, 2009, EPO had outstanding a $50.0 million letter of credit relating to its commodity derivative instruments and a $58.3 million letter of credit related to its Petal GO Zone Bonds. These letter of credit facilities do not reduce the amount available for borrowing under EPO's credit facilities. In addition, Duncan Energy Partners had an outstanding letter of credit in the amount of $1.0 million at September 30, 2009, which reduces the amount available for borrowing under its credit facility.

Credit Ratings of EPO

EPO's senior notes are rated investment-grade. Moody's Investor Services has assigned a rating of Baa3 and Standard & Poor's and Fitch Ratings have each assigned a rating of BBB-. Such ratings reflect only the view of a rating agency and should not be interpreted as a recommendation to buy, sell or hold any security. Any rating can be revised upward or downward or withdrawn at any time by a rating agency if it determines that the circumstances warrant such a change and should be evaluated independently of any other rating.

Cash Flows from Operating, Investing and Financing Activities

The following table summarizes our cash flows from operating, investing and financing activities for the periods indicated (dollars in millions). For information regarding the individual components of our cash flow amounts, see the Unaudited Condensed Statements of Consolidated Cash Flows included under Item 1 of this Quarterly Report.

	For the Nine Months Ended September 30,	
	2009	2008
Net cash flows provided by operating activities	$ 615.4	$ 973.0
Cash used in investing activities	771.4	1,709.1
Cash provided by financing activities	194.8	751.8

The following information highlights the significant period-to-period variances in our cash flow amounts:

Comparison of Nine Months Ended September 30, 2009 with Nine Months Ended September 30, 2008

Operating Activities. Net cash flows provided by operating activities were $615.4 million for the nine months ended September 30, 2009 compared to $973.0 million for the nine months ended September 30, 2008. This $357.6 million decrease in net cash flows provided by operating activities was primarily due to the following:

§ Net cash flows from consolidated operations (excluding cash payments for interest and distributions received from unconsolidated affiliates) decreased $306.6 million period-to-period. Although our gross operating margin increased period-to-period (see "Results of Operations" within this Item 2), the reduction in operating cash flow is generally due to the timing of related cash receipts and disbursements and an increase in cash outlays for forward sales inventory. As a result of energy market conditions, we significantly increased our physical inventory purchases and related forward physical sales commitments during 2009. In general, the significant increase in volumes dedicated to forward physical sales contracts improves the overall utilization and profitability of our fee-based assets.

§ Cash payments for interest increased $44.7 million period-to-period primarily due to increased borrowings to finance our capital spending program and for general partnership purposes.

§ Distributions received from unconsolidated affiliates decreased $6.3 million period-to-period primarily due to lower distributions received from Deepwater Gateway, partially offset by increased distributions received from Cameron Highway.

Investing Activities. Cash used in investing activities was $771.4 million for the nine months ended September 30, 2009 compared to $1.71 billion for the nine months ended September 30, 2008. This $937.7 million decrease in cash used in investing activities was primarily due to the following:

§ Capital spending for property, plant and equipment, net of contributions in aid of construction costs, decreased $626.1 million period-to-period. For additional information related to our capital spending program, see "Capital Spending" included within this Item 2.

§ Restricted cash related to our hedging activities decreased $100.8 million (a cash inflow) during the nine months ended September 30, 2009 primarily due to the reduction of margin requirements related to derivative instruments we utilized. For the nine months ended September 30, 2008, restricted cash related to our hedging activities increased $112.2 million (a cash outflow).

§ Cash used for business combinations decreased $32.6 million period-to-period primarily due to our $23.7 million acquisition of rail and truck terminal facilities located in Mont Belvieu, Texas in May 2009 compared to our $57.1 million acquisition of additional interests in Dixie in August 2008.

§ Investments in unconsolidated affiliates decreased $57.5 million period-to-period primarily due to higher contributions made to Jonah Gas Gathering Company in 2008 compared to 2009.

Financing Activities. Cash provided by financing activities was $194.8 million for the nine months ended September 30, 2009 compared to $751.8 million for the nine months ended September 30, 2008. The $557.0 million decrease in cash provided by financing activities was primarily due to the following:

§ Net borrowings under our consolidated debt agreements were $94.7 million during the nine months ended September 30, 2009 compared to $1.54 billion during the nine months ended September 30, 2008. The $1.44 billion decrease in net borrowings was primarily attributable to lower amounts of senior notes issued period-to-period, the repayment of the $217.6 million Yen Term Loan in March 2009 and an increase in net repayments under EPO's Multi-Year Revolving Credit Facility period-to-period. During the nine months ended September 30, 2008, EPO issued $1.1 billion in senior notes (Senior Notes M and N), compared to $500.0 million in senior notes (Senior Notes P) during the nine months ended September 30, 2009.

§ Cash distributions to our partners increased $89.7 million period-to-period due to increases in our common units outstanding and quarterly distribution rates.

§ Net proceeds from the issuance of common units increased $821.0 million period-to-period primarily due to (i) the January and September 2009 issuances of common units that generated net proceeds of $452.0 million, (ii) the September 2009 private placement of common units that generated net proceeds of $150.0 million and (iii) an increase of $206.9 million in proceeds generated by our DRIP and EUPP period-to-period. Affiliates of EPCO reinvested $226.5 million of their distributions through the DRIP during the nine months ended September 30, 2009.

§ Contributions from noncontrolling interests were $137.4 million for the nine months ended September 30, 2009, which represents the net proceeds that Duncan Energy Partners received from the issuance of an aggregate 8,943,400 of its common units in June and July 2009. Duncan Energy Partners used the net proceeds from this offering to repurchase and cancel an equal number of its common units beneficially owned by EPO.

Capital Spending

The following table summarizes our capital spending by activity for the periods indicated (dollars in millions):

	For the Nine Months Ended September 30,	
	2009	2008
Capital spending for property, plant and equipment, net of contributions in aid of construction costs	$ 838.3	$ 1,464.4
Capital spending for business combinations	24.5	57.1
Capital spending for intangible assets	--	5.1
Capital spending for investments in unconsolidated affiliates	14.5	72.0
Total capital spending	$ 877.3	$ 1,598.6

Based on information currently available and after giving effect to the TEPPCO Merger, we estimate our consolidated capital spending for the fourth quarter of 2009 will approximate $700.0 million, which includes estimated expenditures of $630.0 million for growth capital projects and acquisitions and $70.0 million for sustaining capital expenditures.

Our forecast of consolidated capital expenditures is based on our current announced strategic operating and growth plans. Our strategic operating and growth plans are dependent upon our ability to generate the required funds from either operating cash flows or from other means, including borrowings under debt agreements, issuance of equity, and potential divestitures of certain assets to third and/or related parties. Our forecast of capital expenditures may change due to factors beyond our control, such as weather-related issues, changes in supplier prices or adverse economic conditions. Furthermore, our forecast may change as a result of decisions made by management at a later date, which may include acquisitions or decisions to take on additional partners.

Our success in raising capital, including the formation of joint ventures to share costs and risks, continues to be a principal factor that determines how much capital we can invest. We believe our access to capital resources is sufficient to meet the demands of our current and future operating growth needs, and although we currently intend to make the forecasted expenditures discussed above, we may adjust the timing and amounts of projected expenditures in response to changes in capital markets.

At September 30, 2009, after giving effect to the TEPPCO Merger, we had approximately $497.0 million in purchase commitments outstanding that relate to our capital spending for property, plant and equipment. These remaining commitments primarily relate to construction of our Barnett Shale and Piceance Basin natural gas pipeline projects and the construction of a new NGL fractionator in Mont Belvieu, Texas.

Pipeline Integrity Costs

Our NGL, petrochemical and natural gas pipelines are subject to pipeline safety programs administered by the U.S. Department of Transportation, through its Pipeline and Hazardous Materials Safety Administration, and participating state agencies. These federal and state agencies have issued safety regulations containing requirements for the development of integrity management programs for hazardous liquid pipelines (which include NGL and petrochemical pipelines) and natural gas pipelines. In general, these regulations require companies to assess the condition of their pipelines in certain areas (such as high consequence areas as defined by the regulations) and to perform any necessary repairs.

The following table summarizes our pipeline integrity costs for the periods indicated (dollars in millions):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	2008	2009	2008
Expensed	$ 9.6	$ 14.5	$ 27.8	$ 38.4
Capitalized	9.7	16.2	21.5	38.9
Total	$ 19.3	$ 30.7	$ 49.3	$ 77.3

After giving effect to the TEPPCO Merger, we expect the costs of our pipeline integrity program, irrespective of whether such costs are capitalized or expensed, to approximate $39.4 million for the remainder of 2009.

Other Items

Contractual Obligations

For information regarding year-to-date changes in our contractual obligations, please see Note 14 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report.

Off-Balance Sheet Arrangements

There have been no significant changes with regards to our off-balance sheet arrangements since those reported in our Recast Form 8-K.

Summary of Related Party Transactions

On October 26, 2009, the TEPPCO Merger was completed. Under terms of the merger agreements, TEPPCO and TEPPCO GP became our wholly owned subsidiaries. For additional information regarding this material related party transaction, see “Recent Developments – Merger of TEPPCO and TEPPCO GP with Enterprise Products Partners” within this Item 2.

The following table summarizes other related party transactions for the periods indicated (dollars in millions):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	**2008**	**2009**	**2008**
Revenues from consolidated operations:				
EPCO and affiliates	$ 41.1	$ 47.2	$ 98.9	$ 91.9
Energy Transfer Equity and subsidiaries	54.5	99.6	266.5	413.0
Unconsolidated affiliates	55.8	153.4	155.6	318.8
Total	$ 151.4	$ 300.2	$ 521.0	$ 823.7
Cost of sales:				
EPCO and affiliates	$ 32.1	$ 10.9	$ 75.7	$ 36.5
Energy Transfer Equity and subsidiaries	100.6	50.6	286.5	119.4
Unconsolidated affiliates	13.0	23.7	37.5	75.9
Total	$ 145.7	$ 85.2	$ 399.7	$ 231.8
Operating costs and expenses:				
EPCO and affiliates	$ 91.8	$ 77.1	$ 258.3	$ 238.0
Energy Transfer Equity and subsidiaries	2.0	5.9	5.3	15.0
Unconsolidated affiliates	(2.5)	(3.0)	(7.7)	(7.7)
Total	$ 91.3	$ 80.0	$ 255.9	$ 245.3
General and administrative expenses:				
EPCO and affiliates	$ 16.8	$ 13.4	$ 51.2	$ 44.6
Other expense:				
EPCO and affiliates	$ 0.1	$ --	$ 0.1	$ (0.3)

The following table summarizes our related party receivable and payable amounts at the dates indicated (dollars in millions):

	September 30, 2009	**December 31, 2008**
Accounts receivable - related parties:		
EPCO and affiliates	$ 27.9	$ 26.6
Energy Transfer Equity and subsidiaries	6.4	35.0
Unconsolidated affiliates	3.6	--
Total	$ 37.9	$ 61.6
Accounts payable - related parties:		
EPCO and affiliates	$ 16.9	$ 39.4
Energy Transfer Equity and subsidiaries	27.2	0.2
Unconsolidated affiliates	3.1	--
Total	$ 47.2	$ 39.6

For additional information regarding our related party transactions, see Note 12 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report.

Non-GAAP Reconciliations

The following table presents a reconciliation of our measurement of total non-GAAP gross operating margin to GAAP operating income and income before provision for income taxes (dollars in millions):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2009	**2008**	**2009**	**2008**
Total segment gross operating margin	$ 560.9	$ 478.9	$ 1,618.8	$ 1,535.5
Adjustments to reconcile total segment gross operating margin to operating income:				
Depreciation, amortization and accretion in operating costs and expenses	(160.6)	(138.4)	(467.3)	(408.6)
Non-cash impairment charge included in operating costs and expenses	(1.7)	--	(1.7)	--
Operating lease expense paid by EPCO	(0.2)	(0.5)	(0.5)	(1.5)
Gain from asset sales and related transactions in operating costs and expenses	--	0.9	0.4	1.7
General and administrative costs	(33.9)	(21.8)	(84.7)	(67.0)
Operating income	364.5	319.1	1,065.0	1,060.1
Other expense, net	(128.0)	(101.5)	(373.7)	(287.6)
Income before provision for income taxes	$ 236.5	$ 217.6	$ 691.3	$ 772.5

Recent Accounting Developments

The accounting standard setting bodies have recently issued accounting guidance since those reported in our Recast Form 8-K that will or may affect our future financial statements. The recently issued accounting guidance relates to:

§ The hierarchy of GAAP and the establishment of the ASC (codified under ASC 105, Generally Accepted Accounting Principles);

§ Estimating fair value when the volume and level of activity for the asset or liability have significantly decreased and identifying circumstances that indicate a transaction is not orderly (codified under ASC 820, Fair Value Measurement and Disclosures);

§ Measuring liabilities at fair value (codified under ASC 820);

§ Providing quarterly disclosures about fair value estimates for all financial instruments not measured on the balance sheet at fair value (codified under ASC 825, Financial Instruments);

§ The accounting for, and disclosure of, events that occur after the balance sheet date but before financial statements are issued or are available to be issued (codified under ASC 855, Subsequent Events); and

§ Consolidation of variable interest entities (codified under ASC 810).

For additional information regarding recent accounting developments, see Note 2 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report.

Insurance Matters

EPCO completed its annual insurance renewal process during the second quarter of 2009. In light of recent hurricane and other weather-related events, the renewal of policies for weather-related risks resulted in significant increases in premiums and certain deductibles, as well as changes in the scope of coverage.

EPCO's deductible for onshore physical damage from windstorms increased from $10.0 million per storm to $25.0 million per storm. EPCO's onshore program currently provides $150.0 million per occurrence for named windstorm events compared to $175.0 million per occurrence in the prior year. With respect to offshore assets, the windstorm deductible increased significantly from $10.0 million per storm (with a one-time aggregate deductible of $15.0 million) to $75.0 million per storm. EPCO's offshore program currently provides $100.0 million in the aggregate compared to $175.0 million in the aggregate for the prior year. For non-windstorm events, EPCO's deductible for both onshore and offshore physical damage remained at $5.0 million per occurrence. For certain of our major offshore assets, our producer customers have agreed to provide a specified level of physical damage insurance for named windstorms. For example, the producers associated with our Independence Hub and Marco Polo platforms have agreed to cover windstorm generated physical damage costs up to $250.0 million for each platform.

Business interruption coverage in connection with a windstorm event remains in place for onshore assets, but was eliminated for offshore assets. Onshore assets covered by business interruption insurance must be out-of-service in excess of 60 days before any losses from business interruption will be covered. Furthermore, pursuant to the current policy, we will now absorb 50% of the first $50.0 million of any loss in excess of deductible amounts for our onshore assets.

For additional information regarding weather-related risks, including insurance matters in connection with Hurricanes Ivan, Katrina, Rita, Gustav and Ike, see Note 15 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report.

Item 3. *Quantitative and Qualitative Disclosures about Market Risk.*

In the course of our normal business operations, we are exposed to certain risks, including changes in interest rates, commodity prices and, to a limited extent, foreign exchange rates. In order to manage risks associated with certain identifiable and anticipated transactions, we use derivative instruments. Derivatives are financial instruments whose fair value is determined by changes in a specified benchmark such as interest rates, commodity prices or currency values. Typical derivative instruments include futures, forward contracts, swaps and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities. See Note 4 of the Notes to Unaudited Condensed Financial Statements included under Item 1 of this Quarterly Report for additional information regarding our derivative instruments and hedging activities.

Our exposures to market risk have not changed materially since those reported under Item 7A "Quantitative and Qualitative Disclosures About Market Risk" in our Recast Form 8-K.

Interest Rate Derivative Instruments

We utilize interest rate swaps, treasury locks and similar derivative instruments to manage our exposure to changes in the interest rates of certain consolidated debt agreements. This strategy is a component in controlling our cost of capital associated with such borrowings.

The following tables show the effect of hypothetical price movements on the estimated fair value ("FV") of interest rate swap portfolios at the dates presented (dollars in millions):

Enterprise Products Partners	**Resulting**	**Swap Fair Value at**	
Scenario	**Classification**	**September 30, 2009**	**October 20, 2009**
FV assuming no change in underlying interest rates	*Asset*	$ 46.5	$ 43.7
FV assuming 10% increase in underlying interest rates	*Asset*	40.4	37.7
FV assuming 10% decrease in underlying interest rates	*Asset*	52.7	49.6

Duncan Energy Partners Scenario	Resulting Classification	Swap Fair Value at September 30, 2009	Swap Fair Value at October 20, 2009
FV assuming no change in underlying interest rates	*Liability*	$ (6.0)	$ (6.2)
FV assuming 10% increase in underlying interest rates	*Liability*	(5.8)	(6.0)
FV assuming 10% decrease in underlying interest rates	*Liability*	(6.2)	(6.4)

The following table shows the effect of hypothetical price movements on the estimated fair value of our forward starting swap portfolio at the dates presented (dollars in millions):

Enterprise Products Partners Scenario	Resulting Classification	Swap Fair Value at September 30, 2009	Swap Fair Value at October 20, 2009
FV assuming no change in underlying interest rates	*Asset*	$ 8.1	$ 10.4
FV assuming 10% increase in underlying interest rates	*Asset*	16.4	20.3
FV assuming 10% decrease in underlying interest rates	*Asset*	0.1	0.5

Commodity Derivative Instruments

The prices of natural gas, NGLs, crude oil and certain petrochemical products are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. In order to manage the price risk associated with such products, we enter into commodity derivative instruments such as forwards, basis swaps and futures contracts.

The following table shows the effect of hypothetical price movements on the estimated fair value of our natural gas marketing portfolio at the dates presented (dollars in millions):

Scenario	Resulting Classification	Portfolio Fair Value at September 30, 2009	Portfolio Fair Value at October 20, 2009
FV assuming no change in underlying commodity prices	*Liability*	$ (2.8)	$ (4.2)
FV assuming 10% increase in underlying commodity prices	*Liability*	(11.6)	(13.1)
FV assuming 10% decrease in underlying commodity prices	*Asset*	6.1	4.7

The following table shows the effect of hypothetical price movements on the estimated fair value of our NGL and petrochemical operations portfolio at the dates presented (dollars in millions):

Scenario	Resulting Classification	Portfolio Fair Value at September 30, 2009	Portfolio Fair Value at October 20, 2009
FV assuming no change in underlying commodity prices	*Liability*	$ (84.1)	$ (119.2)
FV assuming 10% increase in underlying commodity prices	*Liability*	(114.6)	(162.1)
FV assuming 10% decrease in underlying commodity prices	*Liability*	(53.6)	(76.3)

Foreign Currency Derivative Instruments

We are exposed to foreign currency exchange risk in connection with our NGL marketing activities in Canada. As a result, we could be adversely affected by fluctuations in currency rates between the U.S. dollar and Canadian dollar. In order to manage this risk, we may enter into foreign exchange purchase contracts to lock in the exchange rate.

In addition, we were exposed to foreign currency exchange risk in connection with a term loan denominated in Japanese yen. We entered into this loan agreement in November 2008 and the loan matured in March 2009. The derivative instrument used to hedge this risk was accounted for as a cash flow hedge and settled upon repayment of the loan.

At September 30, 2009, we had foreign currency derivative instruments with a notional amount of $5.5 million Canadian outstanding. The fair market value of this instrument was an asset of $0.3 million at September 30, 2009.

Item 4. ***Controls and Procedures*****.**

Disclosure Controls and Procedures

As of the end of the period covered by this Quarterly Report, our management carried out an evaluation, with the participation of our general partner's chief executive officer (the "CEO") and our general partner's chief financial officer (the "CFO"), of the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 of the Securities Exchange Act of 1934. Based on this evaluation, as of the end of the period covered by this Report, the CEO and CFO concluded:

(i) that our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including the CEO and CFO, as appropriate to allow timely decisions regarding required disclosure; and

(ii) that our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

There were no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) or in other factors during the third quarter of 2009, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

The certifications of our general partner's CEO and CFO required under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 have been included as exhibits to this Quarterly Report.

PART II. OTHER INFORMATION

Item 1. ***Legal Proceedings*****.**

For information on legal proceedings, see Part I, Item 1, Financial Statements, Note 14, "Commitments and Contingencies – Litigation," of the Notes to Unaudited Condensed Consolidated Financial Statements included in this Quarterly Report, which is incorporated herein by reference.

Item 1A. ***Risk Factors*****.**

Security holders and potential investors in our securities should carefully consider the risk factors set forth in our Annual Report on Form 10-K for the year ended December 31, 2008 in addition to other information in such report and in this Quarterly Report. We have identified these risk factors as important factors that could cause our actual results to differ materially from those contained in any written or oral forward-looking statements made by us or on our behalf.

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

As of September 30, 2009, we and our affiliates could repurchase up to 618,400 additional common units under the December 1998 common unit repurchase program. We did not repurchase any of our common units in connection with this announced program during the nine months ended September 30, 2009.

The following table summarizes our repurchase activity during 2009 in connection with other arrangements:

Period	Total Number of Units Purchased	Average Price Paid per Unit	Total Number of of Units Purchased as Part of Publicly Announced Plans	Maximum Number of Units That May Yet Be Purchased Under the Plans
February 2009	1,357 (1)	$22.64	--	--
May 2009	419 (2)	$24.69	--	--
July 2009	2,300 (3)	$28.10	--	--
August 2009	229,500 (4)	$28.00	--	--

(1) Of the 11,000 restricted unit awards that vested in February 2009 and converted to common units, 1,357 of these units were sold back to the partnership by employees to cover related withholding tax requirements.
(2) Of the 1,500 restricted unit awards that vested in May 2009 and converted into common units, 419 of these units were sold back to the partnership by employees to cover related withholding tax requirements.
(3) Of the 2,300 restricted unit awards that vested in July 2009 and converted into common units, 610 of these units were sold back to the partnership by employees to cover related withholding tax requirements.
(4) Of the 229,500 restricted unit awards that vested in August 2009 and converted into common units, 61,837 of these units were sold back to the partnership by employees to cover related withholding tax requirements.

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.***

Exhibit Number	Exhibit*
2.1	Merger Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed December 15, 2003).
2.2	Amendment No. 1 to Merger Agreement, dated as of August 31, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed September 7, 2004).
2.3	Parent Company Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.2 to Form 8-K filed December 15, 2003).
2.4	Amendment No. 1 to Parent Company Agreement, dated as of April 19, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.1 to Form 8-K filed April 21, 2004).

2.5	Purchase and Sale Agreement (Gas Plants), dated as of December 15, 2003, by and between El Paso Corporation, El Paso Field Services Management, Inc., El Paso Transmission, L.L.C., El Paso Field Services Holding Company and Enterprise Products Operating L.P. (incorporated by reference to Exhibit 2.4 to Form 8-K filed December 15, 2003).
2.6	Agreement and Plan of Merger, dated as of June 28, 2009, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Sub B LLC, TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed June 29, 2009).
2.7	Agreement and Plan of Merger, dated as of June 28, 2009, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Sub A LLC, TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (incorporated by reference to Exhibit 2.2 to Form 8-K filed June 29, 2009).
3.1	Certificate of Limited Partnership of Enterprise Products Partners L.P. (incorporated by reference to Exhibit 3.6 to Form 10-Q filed November 9, 2007).
3.2	Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated effective as of August 8, 2005 (incorporated by reference to Exhibit 3.1 to Form 8-K filed August 10, 2005).
3.3	Amendment No. 1 to the Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P. dated as of December 27, 2007 (incorporated by reference to Exhibit 3.1 to Form 8-K/A filed January 3, 2008).
3.4	Amendment No. 2 to the Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P. dated as of April 14, 2008 (incorporated by reference to Exhibit 10.1 to Form 8-K filed April 16, 2008).
3.5	Amendment No. 3 to the Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P. dated as of November 6, 2008 (incorporated by reference to Exhibit 3.5 to Form 10-Q filed on November 10, 2008).
3.6	Amendment No. 4 to the Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P. dated as of October 26, 2009 (incorporated by reference to Exhibit 3.1 to Form 8-K filed on October 28, 2009).
3.7	Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, dated as of November 7, 2007 (incorporated by reference to Exhibit 3.2 to Form 10-Q filed November 9, 2007).
3.8	First Amendment to Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, dated as of November 6, 2008 (incorporated by reference to Exhibit 3.7 to Form 10-Q filed on November 10, 2008).
3.9	Limited Liability Company Agreement of Enterprise Products Operating LLC dated as of June 30, 2007 (incorporated by reference to Exhibit 3.3 to Form 10-Q filed on August 8, 2007).
3.10	Certificate of Incorporation of Enterprise Products OLPGP, Inc., dated December 3, 2003 (incorporated by reference to Exhibit 3.5 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
3.11	Bylaws of Enterprise Products OLPGP, Inc., dated December 8, 2003 (incorporated by reference to Exhibit 3.6 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
4.1	Form of Common Unit certificate (incorporated by reference to Exhibit 4.1 to Registration Statement on Form S-1/A; File No. 333-52537, filed July 21, 1998).
4.2	Indenture dated as of March 15, 2000, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed March 10, 2000).
4.3	First Supplemental Indenture dated as of January 22, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.4	Second Supplemental Indenture dated as of February 14, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 10-K filed March 31, 2003).

4.5	Third Supplemental Indenture dated as of June 30, 2007, among Enterprise Products Operating L.P., as Original Issuer, Enterprise Products Partners L.P., as Parent Guarantor, Enterprise Products Operating LLC, as New Issuer, and U.S. Bank National Association, as successor Trustee (incorporated by reference to Exhibit 4.55 to Form 10-Q filed on August 8, 2007).
4.6	Amended and Restated Revolving Credit Agreement dated as of November 19, 2007 among Enterprise Products Operating LLC, the financial institutions party thereto as lenders, Wachovia Bank, National Association, as Administrative Agent, Issuing Bank and Swingline Lender, Citibank, N.A. and JPMorgan Chase Bank, as Co-Syndication Agents, and SunTrust Bank, Mizuho Corporate Bank, Ltd. and The Bank of Nova Scotia, as Co-Documentation Agents (incorporated by reference to Exhibit 10.1 to Form 8-K filed on November 20, 2007).
4.7	Amended and Restated Guaranty Agreement dated as of November 19, 2007 executed by Enterprise Products Partners L.P. in favor of Wachovia Bank, National Association, as Administrative Agent (incorporated by reference to Exhibit 10.2 to Form 8-K filed on November 20, 2007).
4.8	Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed on October 6, 2004).
4.9	First Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed on October 6, 2004).
4.10	Second Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed on October 6, 2004).
4.11	Third Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed on October 6, 2004).
4.12	Fourth Supplemental Indenture dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.5 to Form 8-K filed on October 6, 2004).
4.13	Fifth Supplemental Indenture dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed on March 3, 2005).
4.14	Sixth Supplemental Indenture dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed on March 3, 2005).
4.15	Seventh Supplemental Indenture dated as of June 1, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.46 to Form 10-Q filed November 4, 2005).
4.16	Eighth Supplemental Indenture dated as of July 18, 2006, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006).
4.17	Ninth Supplemental Indenture dated as of May 24, 2007, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed by Enterprise Products Partners L.P. on May 24, 2007).

4.18	Tenth Supplemental Indenture dated as of June 30, 2007, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.54 to Form 10-Q filed August 8, 2007).
4.19	Eleventh Supplemental Indenture dated as of September 4, 2007, among Enterprise Products Operating L.P., as Original Issuer, Enterprise Products Operating LLC, as New Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed on September 5, 2007).
4.20	Twelfth Supplemental Indenture dated as of April 3, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed April 3, 2008).
4.21	Thirteenth Supplemental Indenture dated as of April 3, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed April 3, 2008).
4.22	Fourteenth Supplemental Indenture dated as of December 8, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed December 8, 2008).
4.23	Fifteenth Supplemental Indenture dated as of June 10, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed June 10, 2009).
4.24	Sixteenth Supplemental Indenture dated as of October 5, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.25	Seventeenth Supplemental Indenture dated as of October 27, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed October 28, 2009).
4.26	Eighteenth Supplemental Indenture dated as of October 27, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed October 28, 2009).
4.27	Global Note representing $350.0 million principal amount of 6.375% Series B Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.28	Global Note representing $229.2 million principal amount of 6.875% Series B Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 10-K filed March 31, 2003).
4.29	Global Note representing $450.0 million principal amount of 7.50% Senior Notes due 2011 (incorporated by reference to Exhibit 4.1 to Form 8-K filed January 25, 2001).
4.30	Global Note representing $500.0 million principal amount of 4.00% Series B Senior Notes due 2007 with attached Guarantee (incorporated by reference to Exhibit 4.14 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).
4.31	Global Note representing $500.0 million principal amount of 5.60% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.17 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).
4.32	Global Note representing $150.0 million principal amount of 5.60% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.18 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).

4.33	Global Note representing $350.0 million principal amount of 6.65% Series B Senior Notes due 2034 with attached Guarantee (incorporated by reference to Exhibit 4.19 to Form S-3 Registration Statement Reg. No. 333-123150 filed on March 4, 2005).
4.34	Global Note representing $500.0 million principal amount of 4.625% Series B Senior Notes due 2009 with attached Guarantee (incorporated by reference to Exhibit 4.27 to Form 10-K for the year ended December 31, 2004 filed on March 15, 2005).
4.35	Global Note representing $250.0 million principal amount of 5.00% Series B Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.31 to Form 10-Q filed on November 4, 2005).
4.36	Global Note representing $250.0 million principal amount of 5.75% Series B Senior Notes due 2035 with attached Guarantee (incorporated by reference to Exhibit 4.32 to Form 10-Q filed on November 4, 2005).
4.37	Global Note representing $500.0 million principal amount of 4.95% Senior Notes due 2010 with attached Guarantee (incorporated by reference to Exhibit 4.47 to Form 10-Q filed November 4, 2005).
4.38	Form of Junior Subordinated Note, including Guarantee (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006).
4.39	Global Note representing $800.0 million principal amount of 6.30% Senior Notes due 2017 with attached Guarantee (incorporated by reference to Exhibit 4.38 to Form 10-Q filed November 9, 2007).
4.40	Form of Global Note representing $400.0 million principal amount of 5.65% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed April 3, 2008).
4.41	Form of Global Note representing $700.0 million principal amount of 6.50% Senior Notes due 2019 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed April 3, 2008).
4.42	Form of Global Note representing $500.0 million principal amount of 9.75% Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed December 8, 2008).
4.43	Form of Global Note representing $500.0 million principal amount of 4.60% Senior Notes due 2012 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed June 10, 2009).
4.44	Form of Global Note representing $500.0 million principal amount of 5.25% Senior Notes due 2020 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.45	Form of Global Note representing $600.0 million principal amount of 6.125% Senior Notes due 2039 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.46	Form of Global Note representing $490.5 million principal amount of 7.625% Senior Notes due 2012 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 28, 2009).
4.47	Form of Global Note representing $182.6 million principal amount of 6.125% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed October 28, 2009).
4.48	Form of Global Note representing $237.6 million principal amount of 5.90% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 28, 2009).
4.49	Form of Global Note representing $349.7 million principal amount of 6.65% Senior Notes due 2018 with attached Guarantee (incorporated by reference to Exhibit 4.6 to Form 8-K filed October 28, 2009).
4.50	Form of Global Note representing $399.6 million principal amount of 7.55% Senior Notes due 2038 with attached Guarantee (incorporated by reference to Exhibit 4.7 to Form 8-K filed October 28, 2009).
4.51	Form of Global Note representing $285.8 million principal amount of 7.000% Junior Subordinated Notes due 2067 with attached Guarantee (incorporated by reference to Exhibit 4.8 to Form 8-K filed October 28, 2009).

4.52	Replacement Capital Covenant, dated May 24, 2007, executed by Enterprise Products Operating L.P. and Enterprise Products Partners L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 99.1 to Form 8-K filed May 24, 2007).
4.53	First Amendment to Replacement Capital Covenant dated August 25, 2006, executed by Enterprise Products Operating L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 99.2 to Form 8-K filed August 25, 2006).
4.54	Purchase Agreement, dated as of July 12, 2006 between Cerrito Gathering Company, Ltd., Cerrito Gas Marketing, Ltd., Encinal Gathering, Ltd., as Sellers, Lewis Energy Group, L.P., as Guarantor, and Enterprise Products Partners L.P., as Buyer (incorporated by reference to Exhibit 4.6 to Form 10-Q filed August 8, 2006).
4.55	Replacement Capital Covenant, dated October 27, 2009, by and among Enterprise Products Operating LLC and Enterprise Products Partners L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 4.9 to Form 8-K filed October 28, 2009).
10.1	Stipulation and Agreement of Compromise, Settlement and Release, dated August 5, 2009 (incorporated by reference to Exhibit 10.3 to Form 10-Q filed by TEPPCO Partners, L.P. on August 6, 2009).
10.2	Loan Agreement, dated August 5, 2009, by and between Enterprise Products Operating LLC, as Lender, and TEPPCO Partners, L.P., as Borrower (incorporated by reference to Exhibit 10.4 to Form 10-Q filed by TEPPCO Partners, L.P. on August 6, 2009).
10.3	Common Unit Purchase Agreement, dated September 3, 2009, by and between Enterprise Products Partners L.P. and EPCO Holdings, Inc. (incorporated by reference to Exhibit 10.1 to Form 8-K on September 4, 2009).
31.1#	Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise Products Partners L.P. for the September 30, 2009 quarterly report on Form 10-Q.
31.2#	Sarbanes-Oxley Section 302 certification of W. Randall Fowler for Enterprise Products Partners L.P. for the September 30, 2009 quarterly report on Form 10-Q.
32.1#	Section 1350 certification of Michael A. Creel for the September 30, 2009 quarterly report on Form 10-Q.
32.2#	Section 1350 certification of W. Randall Fowler for the September 30, 2009 quarterly report on Form 10-Q.

* With respect to any exhibits incorporated by reference to any Exchange Act filings, the Commission file number for Enterprise Products Partners L.P., Duncan Energy Partners L.P. and Enterprise GP Holdings L.P. and TEPPCO Partners, L.P. are 1-14323, 1-33266, 1-32610 and 1-10403, respectively.

\# Filed with this report.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on November 9, 2009.

ENTERPRISE PRODUCTS PARTNERS L.P.
(A Delaware Limited Partnership)

By: Enterprise Products GP, LLC, as General Partner

By:	/s/ Michael J. Knesek
Name:	Michael J. Knesek
Title:	Senior Vice President, Controller and Principal Accounting Officer of the General Partner

EXHIBIT 31.1

CERTIFICATIONS

I, Michael A. Creel, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Enterprise Products Partners L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 9, 2009

/s/ Michael A. Creel

Name: Michael A. Creel
Title: Chief Executive Officer of Enterprise Products GP, LLC, the General Partner of Enterprise Products Partners L.P.

EXHIBIT 31.2

CERTIFICATIONS

I, W. Randall Fowler, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Enterprise Products Partners L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 9, 2009

/s/ W. Randall Fowler

Name: W. Randall Fowler
Title: Chief Financial Officer of Enterprise Products GP, LLC, the General Partner of Enterprise Products Partners L.P.

EXHIBIT 32.1

SARBANES-OXLEY SECTION 906 CERTIFICATION

CERTIFICATION OF MICHAEL A. CREEL, CHIEF EXECUTIVE OFFICER OF ENTERPRISE PRODUCTS GP, LLC, THE GENERAL PARTNER OF ENTERPRISE PRODUCTS PARTNERS L.P.

In connection with this quarterly report of Enterprise Products Partners L.P. (the “Registrant”) on Form 10-Q for the quarterly period ended September 30, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Michael A. Creel, Chief Executive Officer of Enterprise Products GP, LLC, the General Partner of the Registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

/s/ Michael A. Creel

Name: Michael A. Creel
Title: Chief Executive Officer of Enterprise Products GP, LLC, the General Partner of Enterprise Products Partners L.P.

Date: November 9, 2009

EXHIBIT 32.2

SARBANES-OXLEY SECTION 906 CERTIFICATION

CERTIFICATION OF W. RANDALL FOWLER, CHIEF FINANCIAL OFFICER OF ENTERPRISE PRODUCTS GP, LLC, THE GENERAL PARTNER OF ENTERPRISE PRODUCTS PARTNERS L.P.

In connection with this quarterly report of Enterprise Products Partners L.P. (the “Registrant”) on Form 10-Q for the quarterly period ended September 30, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, W. Randall Fowler, Chief Financial Officer of Enterprise Products GP, LLC, the General Partner of the Registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

/s/ W. Randall Fowler

Name: W. Randall Fowler
Title: Chief Financial Officer of Enterprise Products GP, LLC,
the General Partner of Enterprise Products Partners L.P.

Date: November 9, 2009