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 June 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 460,221,747 common units, including 2,907,950 restricted common units, of Enterprise Products Partners L.P. outstanding at August 1, 2009. These common units trade on the New York Stock Exchange under the ticker symbol "EPD."

ENTERPRISE PRODUCTS PARTNERS L.P.
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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	June 30, 2009	December 31, 2008
Current assets:		
Cash and cash equivalents	$ 65.0	$ 35.4
Restricted cash	184.4	203.8
Accounts and notes receivable – trade, net of allowance for doubtful accounts of $14.7 at June 30, 2009 and $15.1 at December 31, 2008	1,232.2	1,185.5
Accounts receivable – related parties	47.4	61.6
Inventories (see Note 5)	965.8	362.8
Derivative assets (see Note 4)	229.3	202.8
Prepaid and other current assets	144.8	111.8
Total current assets	2,868.9	2,163.7
Property, plant and equipment, net	13,582.0	13,154.8
Investments in unconsolidated affiliates	901.4	949.5
Intangible assets, net of accumulated amortization of $472.0 at June 30, 2009 and $429.9 at December 31, 2008	813.5	855.4
Goodwill	706.9	706.9
Deferred tax asset	1.1	0.4
Other assets	148.7	126.8
Total assets	$ 19,022.5	$ 17,957.5
LIABILITIES AND EQUITY		
Current liabilities:		
Current maturities of long-term debt	$ 181.4	$ --
Accounts payable – trade	278.2	300.5
Accounts payable – related parties	96.0	39.6
Accrued product payables	1,526.2	1,142.4
Accrued interest payable	169.4	151.9
Other accrued expenses	32.3	48.8
Derivative liabilities (see Note 4)	337.0	287.2
Other current liabilities	191.1	252.7
Total current liabilities	2,811.6	2,223.1
Long-term debt: (see Note 9)		
Senior debt obligations – principal	7,950.1	7,813.4
Junior subordinated notes – principal	1,232.7	1,232.7
Other	41.5	62.3
Total long-term debt	9,224.3	9,108.4
Deferred tax liabilities	68.8	66.1
Other long-term liabilities	98.9	81.3
Commitments and contingencies		
Equity: (see Note 10)		
Enterprise Products Partners L.P. partners' equity:		
Limited Partners:		
Common units (457,313,797 units outstanding at June 30, 2009 and 439,354,731 units outstanding at December 31, 2008)	6,278.7	6,036.9
Restricted common units (2,935,450 units outstanding at June 30, 2009 and 2,080,600 units outstanding at December 31, 2008)	32.1	26.2
General partner	128.6	123.6
Accumulated other comprehensive loss	(130.9)	(97.2)
Total Enterprise Products Partners L.P. partners' equity	6,308.5	6,089.5
Noncontrolling interest	510.4	389.1
Total equity	6,818.9	6,478.6
Total liabilities and equity	$ 19,022.5	$ 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 June 30,		For the Six Months Ended June 30,	
	2009	2008	2009	2008
Revenues:				
Third parties	$ 3,382.8	$ 6,116.9	$ 6,561.4	$ 11,500.7
Related parties	125.1	222.8	369.6	523.5
Total revenues (see Note 11)	3,507.9	6,339.7	6,931.0	12,024.2
Costs and expenses:				
Operating costs and expenses:				
Third parties	2,925.3	5,824.7	5,756.9	10,959.3
Related parties	208.9	135.3	418.6	311.9
Total operating costs and expenses	3,134.2	5,960.0	6,175.5	11,271.2
General and administrative costs:				
Third parties	11.2	10.5	16.4	14.0
Related parties	16.6	13.5	34.4	31.2
Total general and administrative costs	27.8	24.0	50.8	45.2
Total costs and expenses	3,162.0	5,984.0	6,226.3	11,316.4
Equity in income (loss) of unconsolidated affiliates	(17.6)	18.6	(4.2)	33.2
Operating income	328.3	374.3	700.5	741.0
Other income (expense):				
Interest expense	(126.2)	(95.8)	(246.6)	(187.7)
Interest income	0.6	1.0	1.2	2.6
Other, net	(0.4)	(0.3)	(0.3)	(1.0)
Total other expense, net	(126.0)	(95.1)	(245.7)	(186.1)
Income before provision for income taxes	202.3	279.2	454.8	554.9
Provision for income taxes	(2.2)	(6.9)	(17.4)	(10.6)
Net income	200.1	272.3	437.4	544.3
Net income attributable to noncontrolling interest	(13.5)	(9.0)	(25.5)	(21.4)
Net income attributable to Enterprise Products Partners L.P.	$ 186.6	$ 263.3	$ 411.9	$ 522.9
Net income allocated to:				
Limited partners	$ 147.0	$ 227.7	$ 333.3	$ 452.9
General partner	$ 39.6	$ 35.6	$ 78.6	$ 70.0
Basic and diluted earnings per unit (see Note 13)	$ 0.32	$ 0.52	$ 0.73	$ 1.03

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2009	2008	2009	2008
Net income	$ 200.1	$ 272.3	$ 437.4	$ 544.3
Other comprehensive income (loss):				
Cash flow hedges:				
Commodity derivative instrument gains (losses) during period	(76.6)	31.1	(138.6)	119.9
Reclassification adjustment for (gains) losses included in net income related to commodity derivative instruments	66.3	(16.9)	98.5	(12.7)
Interest rate derivative instrument gains (losses) during period	15.8	4.2	15.1	(21.8)
Reclassification adjustment for (gains) losses included in net income related to interest rate derivative instruments	1.1	(0.8)	2.0	(2.4)
Foreign currency derivative gains (losses)	0.1	(0.1)	(10.5)	(1.3)
Total cash flow hedges	6.7	17.5	(33.5)	81.7
Foreign currency translation adjustment	1.0	0.5	0.6	0.1
Change in funded status of pension and postretirement plans, net of tax	--	--	--	(0.3)
Total other comprehensive income (loss)	7.7	18.0	(32.9)	81.5
Comprehensive income	207.8	290.3	404.5	625.8
Comprehensive income attributable to noncontrolling interest	(13.7)	(12.5)	(26.3)	(21.1)
Comprehensive income attributable to Enterprise Products Partners L.P.	$ 194.1	$ 277.8	$ 378.2	$ 604.7

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 Six Months Ended June 30, 2009	For the Six Months Ended June 30, 2008
Operating activities:		
Net income	$ 437.4	$ 544.3
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	312.9	274.3
Equity in (income) loss of unconsolidated affiliates	4.2	(33.2)
Distributions received from unconsolidated affiliates	38.5	56.0
Operating lease expense paid by EPCO, Inc.	0.3	1.0
Gain from asset sales and related transactions	(0.4)	(0.8)
Deferred income tax expense	1.8	2.5
Changes in fair market value of derivative instruments	(11.7)	9.6
Effect of pension settlement recognition	(0.1)	(0.1)
Net effect of changes in operating accounts (see Note 16)	(345.2)	(156.9)
Net cash flows provided by operating activities	437.7	696.7
Investing activities:		
Capital expenditures	(640.0)	(1,091.2)
Contributions in aid of construction costs	10.3	17.8
Decrease in restricted cash	19.4	71.0
Cash used for business combinations	(23.7)	--
Acquisition of intangible assets	--	(5.1)
Investments in unconsolidated affiliates	(12.5)	(25.0)
Other proceeds from investing activities	4.3	0.5
Cash used in investing activities	(642.2)	(1,032.0)
Financing activities:		
Borrowings under debt agreements	2,785.1	3,914.7
Repayments of debt	(2,471.2)	(3,063.0)
Debt issuance costs	(5.4)	(8.6)
Distributions paid to partners	(566.4)	(509.0)
Distributions paid to noncontrolling interest (see Note 10)	(27.8)	(29.1)
Net proceeds from issuance of common units	398.8	38.0
Contributions from noncontrolling interest (see Note 10)	123.2	--
Acquisition of treasury units	--	(0.7)
Monetization of interest rate derivative instruments	--	(22.1)
Cash provided by financing activities	236.3	320.2
Effect of exchange rate changes on cash	(2.2)	0.1
Net change in cash and cash equivalents	31.8	(15.1)
Cash and cash equivalents, January 1	35.4	39.7
Cash and cash equivalents, June 30	$ 65.0	$ 24.7

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	333.3	78.6	--	25.5	437.4
Operating leases paid by EPCO, Inc.	0.3	--	--	--	0.3
Cash distributions to partners	(484.4)	(81.7)	--	--	(566.1)
Unit option reimbursements to EPCO, Inc.	(0.3)	--	--	--	(0.3)
Distributions paid to noncontrolling interest (see Note 10)	--	--	--	(27.8)	(27.8)
Net proceeds from issuance of common units	390.6	8.0	--	--	398.6
Proceeds from exercise of unit options	0.2	--	--	--	0.2
Contributions from noncontrolling interest (see Note 10)	--	--	--	122.8	122.8
Amortization of equity awards	8.0	0.1	--	--	8.1
Foreign currency translation adjustment	--	--	0.6	--	0.6
Cash flow hedges	--	--	(34.3)	0.8	(33.5)
Balance, June 30, 2009	$ 6,310.8	$ 128.6	$ (130.9)	$ 510.4	$ 6,818.9

	Enterprise Products Partners L.P.				
	Limited Partners	General Partner	Accumulated Other Comprehensive Income	Noncontrolling Interest	Total
Balance, December 31, 2007	$ 5,992.9	$ 122.3	$ 19.1	$ 427.8	$ 6,562.1
Net income	452.9	70.0	--	21.4	544.3
Operating leases paid by EPCO, Inc.	1.0	--	--	--	1.0
Cash distributions to partners	(438.8)	(69.7)	--	--	(508.5)
Unit option reimbursements to EPCO, Inc.	(0.5)	--	--	--	(0.5)
Distributions paid to noncontrolling interest (see Note 10)	--	--	--	(29.1)	(29.1)
Net proceeds from issuance of common units	36.7	0.7	--	--	37.4
Proceeds from exercise of unit options	0.6	--	--	--	0.6
Amortization of equity awards	5.3	0.1	--	--	5.4
Acquisition of treasury units	(0.7)	--	--	--	(0.7)
Foreign currency translation adjustment	--	--	0.1	--	0.1
Change in funded status of pension and postretirement plans	--	--	(0.3)	--	(0.3)
Cash flow hedges	--	--	81.9	(0.2)	81.7
Balance, June 30, 2008	$ 6,049.4	$ 123.4	$ 100.8	$ 419.9	$ 6,693.5

See Notes to Unaudited Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
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

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" mean TEPPCO Partners, L.P., a publicly traded limited partnership, the common units of which are listed on the NYSE under the ticker symbol "TPP." References to "TEPPCO GP" refer to Texas Eastern Products Pipeline Company, LLC, which is the general partner of TEPPCO and is wholly owned by Enterprise GP Holdings. On June 28, 2009, we and TEPPCO (including TEPPCO GP) entered into definitive agreements to merge. See Note 12 for additional information regarding the merger agreements.

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 the provisions of Statement of Financial Accounting Standards ("SFAS") 160 (Accounting Standards Codification ("ASC") 810), *Noncontrolling Interests in Consolidated Financial Statements – an amendment of ARB No. 51*. SFAS 160 established accounting and reporting standards for noncontrolling interests, which were previously identified as minority interest in our financial statements. This new standard 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 10 for additional information regarding noncontrolling interest.

The consolidated financial statements included in this Quarterly Report have been retrospectively adjusted to reflect the changes required by SFAS 160. As a result, net income reported for the three and six months ended June 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 six months ended June 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 retrospectively adjusted portions of our Annual Report on Form 10-K for the year ended December 31, 2008 to reflect our adoption of SFAS 160 and Emerging Issues Task Force ("EITF") 07-4 (ASC 260), *Application of the Two Class Method Under FASB Statement No. 128 to Master Limited Partnerships*, 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, 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:

	June 30, 2009		December 31, 2008	
Financial Instruments	**Carrying Value**	**Fair Value**	**Carrying Value**	**Fair Value**
Financial assets:				
Cash and cash equivalents, including restricted cash	$ 249.4	$ 249.4	$ 239.2	$ 239.2
Accounts receivable	1,279.6	1,279.6	1,247.1	1,247.1
Financial liabilities:				
Accounts payable and accrued expenses	2,102.1	2,102.1	1,683.2	1,683.2
Other current liabilities	191.1	191.1	252.7	252.7
Fixed-rate debt (principal amount)	7,986.7	7,760.9	7,704.3	6,639.0
Variable-rate debt	1,377.5	1,377.5	1,341.8	1,341.8

Recent Accounting Developments

The following information summarizes recently issued accounting guidance since those reported in our Recast Form 8-K that will or may affect our future financial statements.

In April 2009, the Financial Accounting Standards Board ("FASB") issued new guidance in the form of FASB Staff Positions ("FSPs") in an effort to clarify certain fair value accounting rules. FSP FAS 157-4 (ASC 820), *Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly*, establishes a process to determine whether a market is not active and a transaction is not distressed. FSP FAS 157-4 states that companies should look at several factors and use judgment to ascertain if a formerly active market has become inactive. When estimating fair value, FSP FAS 157-4 requires companies to place more weight on observable transactions determined to be orderly and less weight on transactions for which there is insufficient information to determine whether the transaction is orderly (entities do not have to incur undue cost and effort in making this determination). The FASB also issued FSP FAS 107-1 and APB 28-1 (ASC 825), *Interim Disclosures About Fair Value of Financial Instruments*. This FSP requires that companies provide qualitative and quantitative information about fair value estimates for all financial instruments not measured on the balance sheet at fair value in each interim report. Previously, this was only an annual requirement. We adopted these FSPs on June 30, 2009. Our adoption of this new guidance did not have a material impact on our financial statements or related disclosures.

In May 2009, the FASB issued SFAS 165 (ASC 855), *Subsequent Events*, which establishes general standards of 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. SFAS 165 requires the disclosure of the date through which an entity has evaluated subsequent events and the basis for that date. We adopted SFAS 165 on June 30, 2009. Our adoption of this guidance did not have any impact on our financial position, results of operations or cash flows.

In June 2009, the FASB issued SFAS 167 (ASC 810), *Amendments to FASB Interpretation No. 46(R)*, which amended consolidation guidance for variable interest entities ("VIEs") under FASB Interpretation ("FIN") No. 46(R) (ASC 810-10), *Consolidation of Variable Interest Entities*. 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 included in consolidation. A business enterprise must consolidate a VIE when that enterprise has a variable interest that will cover most of the entity's expected losses and/or receive most of the entity's anticipated residual return. SFAS 167, among other things, 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. SFAS 167 is effective for us on January 1, 2010. At June 30, 2009, we did not have any VIEs; therefore, our adoption of this new guidance is not expected to have a material impact on our consolidated financial statements.

In June 2009, the FASB also issued SFAS 168 (ASC 105), *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles – a replacement of FASB Statement No. 162*, which establishes the ASC as the source of authoritative GAAP recognized by the FASB to be applied by nongovernmental entities. The ASC is a reorganization of current GAAP into a topical format that eliminates the current GAAP hierarchy and establishes two levels of guidance – authoritative and nonauthoritative. All guidance contained in the ASC carries an equal level of authority. Rules and interpretive releases of the SEC under federal securities laws are also sources of authoritative GAAP for SEC registrants. SFAS 168 identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements of nongovernmental entities that are presented in conformity with GAAP. We will adopt SFAS 168 on September 30, 2009. Our adoption of this guidance is not expected to have any impact on our financial position, results of operations or cash flows. References to specific GAAP in our consolidated financial statements after our adoption of SFAS 168 will refer exclusively to the ASC. We have elected to provide references to the ASC parenthetically in this Quarterly Report.

Restricted Cash

Restricted cash represents amounts held in connection with our commodity derivative instruments portfolio and New York Mercantile Exchange ("NYMEX") physical natural gas purchases. Additional cash may be restricted to maintain our positions as commodity prices fluctuate or deposit requirements change. At June 30, 2009 and December 31, 2008, our restricted cash amounts were $184.4 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 August 6, 2009, which is the date our Unaudited Condensed Consolidated Financial Statements and Notes are being issued.

Note 3. Accounting for Equity Awards

We account for equity awards in accordance with SFAS 123(R) (ASC 505 and 718), *Share-Based Payment*. Such awards were not material to our consolidated financial position, results of operations or cash flows for all periods presented. The amount of equity-based compensation allocable to our businesses was $5.3 million and $3.5 million for the three months ended June 30, 2009 and 2008, respectively. For the six months ended June 30, 2009 and 2008, the amount of equity-based compensation allocable to our businesses was $8.2 million and $6.3 million, respectively.

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.

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 June 30, 2009, a total of 301,600 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	(25,000)	13.16		
Forfeited	(365,000)	26.38		
Outstanding at June 30, 2009	1,808,500	26.39	4.8	$ 1.5
Options exercisable at June 30, 2009	403,500	21.33	3.9	$ 1.5

(1) Aggregate intrinsic value reflects fully vested unit options at June 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 June 30, 2009 and 2008 was $0.2 million and $0.4 million, respectively. For the six months ended June 30, 2009 and 2008, the total intrinsic value of option awards exercised was $0.3 million and $0.5 million, respectively. At June 30, 2009, the estimated total unrecognized compensation cost related to nonvested unit option awards granted under the EPCO 1998 Plan was $1.3 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 2.0 years.

During the six months ended June 30, 2009 and 2008, we received cash of $0.2 million and $0.6 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 $0.3 million and $0.5 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)	1,011,350	$ 20.63
Vested	(12,500)	27.59
Forfeited	(144,000)	29.41
Restricted units at June 30, 2009	2,935,450	

(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) Aggregate grant date fair value of restricted unit awards issued during 2009 was $20.9 million based on grant date market prices of our common units ranging from $20.08 to $24.92 per unit and an estimated forfeiture rate ranging between 4.6% and 17%.

The total fair value of restricted unit awards that vested during the six months ended June 30, 2009 was $0.3 million. Such amount was immaterial for the three months ended June 30, 2009. At June 30, 2009, the estimated total unrecognized compensation cost related to nonvested restricted unit awards granted under the EPCO 1998 Plan was $44.2 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 June 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 June 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 June 30, 2009 (2)	2,135,000	25.97	5.2

(1) 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%; and (vi) an estimated forfeiture rate of 17%.
(2) No unit options were exercisable as of June 30, 2009.

At June 30, 2009, the estimated total unrecognized compensation cost related to nonvested unit option awards granted under the EPD 2008 LTIP was $7.1 million. We expect to recognize our share of this cost over a weighted-average period of 3.6 years in accordance with the ASA.

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

Employee Partnerships

As of June 30, 2009, the estimated total unrecognized compensation cost related to the five Employee Partnerships was $39.9 million. We will recognize our share of these costs in accordance with the ASA over a weighted-average period of 4.5 years.

DEP GP Unit Appreciation Rights

At June 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 June 30, 2009 and December 31, 2008, we had accrued an immaterial liability for compensation related to these UARs.

Note 4. Derivative Instruments and Hedging Activities

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.

SFAS 133 (ASC 815), *Accounting for Derivative Instruments and Hedging Activities*, requires companies to recognize derivative instruments at fair value as either assets or liabilities on the balance sheet. While the standard requires that all derivatives 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 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.

On January 1, 2009, we adopted the disclosure requirements of SFAS 161 (ASC 815), *Disclosures About Derivative Financial Instruments and Hedging Activities*. SFAS 161 requires enhanced qualitative and quantitative disclosure requirements regarding derivative instruments. This footnote reflects the new disclosure standard.

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.

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The following table summarizes our interest rate derivative instruments outstanding at June 30, 2009, all of which were designated as hedging instruments under SFAS 133:

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 3.5%	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	6 fixed-to-floating swaps	$350.0	6/09 to 8/12	4.6% to 2.8%	Fair value hedge
Duncan Energy Partners:					
Variable-interest rate borrowings	3 floating-to-fixed swaps	$175.0	9/07 to 9/10	0.6% to 4.6%	Cash flow hedge

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 other comprehensive income and amortized to earnings using the effective interest method over the estimated 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 other comprehensive income during the first quarter of 2008 related to these terminations. We recognized no losses in other comprehensive income during the second quarter of 2008 in connection with such terminations.

In the first quarter of 2009, we entered into two 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	3.293%	Cash flow hedge
Future debt offering	1 forward starting swap	$150.0	2/11 to 2/21	3.4615%	Cash flow hedge

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 June 30, 2009:

Derivative Purpose	Volume (1) Current	Volume (1) Long-Term (2)	Accounting Treatment
Derivatives designated as hedging instruments under SFAS 133:			
Enterprise Products Partners:			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction ("PTR") (3)	31.7 Bcf	n/a	Cash flow hedge
Forecasted NGL sales	2.2 MMBbls	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchases of natural gas liquids	0.1 MMBbls	n/a	Cash flow hedge
Natural gas liquids inventory management activities	n/a	0.1 MMBbls	Cash flow hedge
Forecasted sales of octane enhancement products	1.5 MMBbls	n/a	Cash flow hedge
Natural gas marketing:			
Natural gas storage inventory management activities	7.4 Bcf	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products	2.3 MMBbls	n/a	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products	5.0 MMBbls	0.8 MMBbls	Cash flow hedge
Derivatives not designated as hedging instruments under SFAS 133:			
Enterprise Products Partners:			
Natural gas risk management activities (4) (5)	296.1 Bcf	10.4 Bcf	Mark-to-market
Duncan Energy Partners:			
Natural gas risk management activities (5)	1.6 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 ("Btu") 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 32.3 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 under SFAS 133. At June 30, 2009, the volume hedged under these contracts was 9.6 million barrels ("MMBbls").

Certain of our derivative instruments do not meet the hedge accounting requirements of SFAS 133 and are accounted for as economic hedges using mark-to-market accounting.

Our predominant hedging strategy is a program to hedge a portion of our margin from natural gas processing. The objective of this 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 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 June 30, 2009, this program had hedged future estimated gross margins (before plant operating expenses) of $269.8 million on 10.4 MMBbls of forecasted NGL forward sales transactions extending through 2009.

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 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, these transactions are accounted for as cash flow hedges.

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.

We had one foreign currency derivative instrument with a notional amount of $1.7 million Canadian outstanding at June 30, 2009. The fair market value of this instrument was an asset of $0.1 million at June 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 June 30, 2009, the aggregate fair value of our over-the-counter derivative instruments in a net liability position was $8.0 million, of which approximately $7.8 million was subject to a credit rating contingent feature. If our credit ratings were downgraded to Ba2/BB, approximately $2.8 million would be payable as a margin deposit to the counterparties, and if our credit ratings were downgraded to Ba3/BB- or below, approximately $7.8 million would be payable as a margin deposit to the counterparties. 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			
	June 30, 2009		December 31, 2008		June 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 under SFAS 133								
Interest rate derivatives	Derivative assets	$ 18.7	Derivative assets	$ 7.8	Derivative liabilities	$ 5.3	Derivative liabilities	$ 5.9
Interest rate derivatives	Other assets	32.3	Other assets	39.0	Other liabilities	4.7	Other liabilities	3.9
Total interest rate derivatives		51.0		46.8		10.0		9.8
Commodity derivatives	Derivative assets	101.8	Derivative assets	150.5	Derivative liabilities	228.3	Derivative liabilities	253.5
Commodity derivatives	Other assets	0.1	Other assets	--	Other liabilities	3.7	Other liabilities	0.2
Total commodity derivatives (1)		101.9		150.5		232.0		253.7
Foreign currency derivatives (2)	Derivative assets	0.1	Derivative assets	9.3	Derivative liabilities	--	Derivative liabilities	--
Total derivatives designated as hedging instruments		$ 153.0		$ 206.6		$ 242.0		$ 263.5
Derivatives not designated as hedging instruments under SFAS 133								
Commodity derivatives	Derivative assets	$ 108.7	Derivative assets	$ 35.2	Derivative liabilities	$ 103.4	Derivative liabilities	$ 27.7
Commodity derivatives	Other assets	0.2	Other assets	--	Other liabilities	0.1	Other liabilities	--
Total commodity derivatives		108.9		35.2		103.5		27.7
Foreign currency derivatives	Derivative assets	--	Derivative assets	--	Derivative liabilities	--	Derivative liabilities	0.1
Total derivatives not designated as hedging instruments		$ 108.9		$ 35.2		$ 103.5		$ 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 under SFAS 133 on our condensed statements of income for the periods indicated:

Derivatives in SFAS 133 Fair Value Hedging Relationships	Location	Gain/(Loss) Recognized in Income on Derivative			
		For the Three Months Ended June 30,		For the Six Months Ended June 30,	
		2009	2008	2009	2008
Interest rate derivatives	Interest expense	$ (14.9)	$ (32.5)	$ (16.2)	$ (5.9)
Commodity derivatives	Revenue	(1.0)	--	(1.1)	--
Total		$ (15.9)	$ (32.5)	$ (17.3)	$ (5.9)

Derivatives in SFAS 133 Fair Value Hedging Relationships	Location	Gain/(Loss) Recognized in Income on Hedged Item			
		For the Three Months Ended June 30,		For the Six Months Ended June 30,	
		2009	2008	2009	2008
Interest rate derivatives	Interest expense	$ 14.3	$ 32.5	$ 15.6	$ 5.9
Commodity derivatives	Revenue	1.0	--	1.1	--
Total		$ 15.3	$ 32.5	$ 16.7	$ 5.9

The following tables present the effect of our derivative instruments designated as cash flow hedges under SFAS 133 on our condensed statements of income for the periods indicated:

Derivatives in SFAS 133 Cash Flow Hedging Relationships	Change in Value Recognized in OCI on Derivative (Effective Portion)			
	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2009	2008	2009	2008
Interest rate derivatives	$ 15.8	$ 4.2	$ 15.1	$ (21.8)
Commodity derivatives – Revenue	75.8	(14.4)	65.8	(4.9)
Commodity derivatives – Operating costs and expenses	(152.4)	45.5	(204.4)	124.8
Foreign currency derivatives	0.1	(0.1)	(10.5)	(1.3)
Total	$ (60.7)	$ 35.2	$ (134.0)	$ 96.8

Derivatives in SFAS 133 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 June 30,		For the Six Months Ended June 30,	
		2009	2008	2009	2008
Interest rate derivatives	Interest expense	$ (1.1)	$ 0.8	$ (2.0)	$ 2.4
Commodity derivatives	Revenue	4.4	(3.1)	19.7	(6.1)
Commodity derivatives	Operating costs and expenses	(70.7)	20.0	(118.2)	18.8
Total		$ (67.4)	$ 17.7	$ (100.5)	$ 15.1

Derivatives in SFAS 133 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 June 30,		For the Six Months Ended June 30,	
		2009	2008	2009	2008
Commodity derivatives	Revenue	$ (0.7)	$ (0.5)	$ (0.7)	$ --
Commodity derivatives	Operating costs and expenses	(0.2)	0.5	(1.3)	2.8
Total		$ (0.9)	$ --	$ (2.0)	$ 2.8

Over the next twelve months, we expect to reclassify $4.4 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 $150.2 million of AOCI attributable to commodity derivative instruments to earnings, $120.6 million as an increase in operating costs and expenses and $29.6 million as a reduction in revenues.

The following table presents the effect of our derivative instruments not designated as hedging instruments under SFAS 133 on our condensed statements of income for the periods indicated:

Derivatives Not Designated as SFAS 133 Hedging Instruments	Location	Gain/(Loss) Recognized in Income on Derivative			
		For the Three Months Ended June 30,		For the Six Months Ended June 30,	
		2009	2008	2009	2008
Commodity derivatives (1)	Revenue	$ 7.2	$ (4.2)	$ 31.9	$ (2.9)
Commodity derivatives	Operating costs and expenses	--	(5.3)	--	(9.0)
Foreign currency derivatives	Other income	--	--	(0.1)	--
Total		$ 7.2	$ (9.5)	$ 31.8	$ (11.9)

(1) Amounts for the three and six months ended June 30, 2009 include $2.7 million and $2.9 million of gains on derivatives that were excluded from fair value hedging relationships, respectively.

SFAS 157 – Fair Value Measurements

SFAS 157 (ASC 820) defines fair value 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.

SFAS 157 established a three-tier hierarchy 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 SFAS 157 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 NYMEX). 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 LIBOR 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 due to the forward markets for these products being less liquid.

The following table sets forth, by level within the fair value hierarchy, our financial assets and liabilities measured on a recurring basis at June 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	$ --	$ 51.0	$ --	$ 51.0
Commodity derivative instruments	12.7	179.0	19.1	210.8
Foreign currency derivatives	--	0.1	--	0.1
Total	$ 12.7	$ 230.1	$ 19.1	$ 261.9
Financial liabilities:				
Interest rate derivative instruments	$ --	$ 10.0	$ --	$ 10.0
Commodity derivative instruments	58.2	269.0	8.3	335.5
Total	$ 58.2	$ 279.0	$ 8.3	$ 345.5

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 Six Months Ended June 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)

(1) There were $0.1 million of unrealized gains and $0.2 million of unrealized losses included in these amounts for the three and six months ended June 30, 2009, respectively. For the three and six months ended June 30, 2008, there were no unrealized gains or losses included in these amounts.

We adopted the provisions of SFAS 157 that apply to nonfinancial assets and liabilities on January 1, 2009. Our adoption of this guidance had no impact on our financial position, results of operations or cash flows. 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 fair value adjustments for such assets or liabilities reflected in our consolidated financial statements for the three and six months ended June 30, 2009.

Note 5. Inventories

Our inventory amounts were as follows at the dates indicated:

	June 30, 2009	December 31, 2008
Working inventory (1)	$ 438.8	$ 200.4
Forward sales inventory (2)	527.0	162.4
Total inventory	$ 965.8	$ 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. Of the $527.0 million in forward sales inventory at June 30, 2009, approximately $432.0 million relates to forward sales NGL volumes. In general, the significant increase in volumes dedicated to forward physical sales contracts improves the overall utilization and profitability of our fee-based assets. The cash invested in forward sales NGL inventories is expected to be recovered within the next twelve months, with approximately $163.4 million realized by December 31, 2009.

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. We value our inventories 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 $2.70 billion and $5.51 billion for the three months ended June 30, 2009 and 2008, respectively. For the six months ended June 30, 2009 and 2008, our costs of sales amounts were $5.33 billion and $10.41 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. For the three months ended June 30, 2009 and 2008, we recognized LCM adjustments of $0.3 million and $0.7 million, respectively. We recognized LCM adjustments of $6.0 million and $4.8 million for the six months ended June 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	June 30, 2009	December 31, 2008
Plants and pipelines (1)	3-45 (5)	$ 13,863.8	$ 12,296.3
Underground and other storage facilities (2)	5-35 (6)	930.8	900.7
Platforms and facilities (3)	20-31	637.5	634.8
Transportation equipment (4)	3-10	39.3	38.7
Land		59.0	54.6
Construction in progress		669.8	1,604.7
Total		16,200.2	15,529.8
Less accumulated depreciation		2,618.2	2,375.0
Property, plant and equipment, net		$ 13,582.0	$ 13,154.8

(1) Plants and pipelines include processing plants; NGL, petrochemical, 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 June 30,		For the Six Months Ended June 30,	
	2009	2008	2009	2008
Depreciation expense (1)	$ 130.5	$ 114.0	$ 255.5	$ 223.8
Capitalized interest (2)	5.6	17.6	17.7	35.7

(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.

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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 six months ended June 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		(11.1)
Revisions in estimated cash flows		21.3
Accretion expense		1.1
ARO liability balance, June 30, 2009	$	49.4

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 $11.1 million of costs through June 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 June 30, 2009 and December 31, 2008 includes $24.9 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 $1.7 million for the last six months of 2009, $3.4 million for each of 2010 and 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 June 30, 2009	June 30, 2009	December 31, 2008
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C.	13.1%	$ 31.6	$ 37.7
K/D/S Promix, L.L.C. (“Promix”)	50%	47.8	46.4
Baton Rouge Fractionators LLC	32.2%	23.3	24.1
Skelly-Belvieu Pipeline Company, L.L.C. (“Skelly-Belvieu”)	49%	37.0	36.0
Onshore Natural Gas Pipelines & Services:			
Jonah Gas Gathering Company (“Jonah”)	19.4%	250.4	258.1
Evangeline (1)	49.5%	5.0	4.5
White River Hub, LLC	50%	27.2	21.4
Offshore Pipelines & Services:			
Poseidon Oil Pipeline, L.L.C. (“Poseidon”)	36%	59.8	60.2
Cameron Highway Oil Pipeline Company (“Cameron Highway”)	50%	246.7	250.8
Deepwater Gateway, L.L.C.	50%	102.9	104.8
Neptune Pipeline Company, L.L.C. (“Neptune”)	25.7%	54.5	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%	11.7	12.6
La Porte (3)	50%	3.5	3.9
Total		$ 901.4	$ 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 $55.4 million and $56.6 million at June 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 $0.7 million and $0.5 million for the three months ended June 30, 2009 and 2008, respectively. For the six months ended June 30, 2009 and 2008, amortization of such amounts was $1.2 million and $1.0 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 June 30,		For the Six Months Ended June 30,	
	2009	2008	2009	2008
NGL Pipelines & Services	$ 2.3	$ 1.6	$ 3.5	$ (0.7)
Onshore Natural Gas Pipelines & Services	7.1	5.5	14.3	11.3
Offshore Pipelines & Services	(27.4)	11.2	(22.7)	21.9
Petrochemical Services	0.4	0.3	0.7	0.7
Total	$ (17.6)	$ 18.6	$ (4.2)	$ 33.2

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 and net income for the second quarter of 2009 reflect a non-cash charge of $34.2 million. This loss represents our cumulative investment in TOPS through the date of dissociation and reflects our capital contributions to TOPS for construction in progress amounts. We believe that the dissociation discharged our affiliate with respect to further obligations under the TOPS partnership agreement, and accordingly, us from the associated liability under the related parent guarantee; therefore, we have not recorded any amounts related to such guarantee. The wholly owned subsidiary of TEPPCO that was a partner in TOPS also dissociated from the partnership effective April 16, 2009. See Note 14 for litigation matters associated with our dissociation from TOPS.

On a quarterly basis, we monitor the underlying business fundamentals of our investments in unconsolidated affiliates and test such investments for impairment when impairment indicators are present. As a result of our reviews for the second quarter of 2009, no impairment charges were required. We have the intent and ability to hold these investments, which are integral to our operations.

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					
	June 30, 2009			June 30, 2008		
	Revenues	Operating Income	Net Income	Revenues	Operating Income	Net Income
NGL Pipelines & Services	$ 46.1	$ 7.8	$ 7.9	$ 74.1	$ 8.1	$ 8.2
Onshore Natural Gas Pipelines & Services	105.5	32.5	32.3	186.0	28.7	27.7
Offshore Pipelines & Services	33.8	13.4	13.2	39.9	23.2	19.9
Petrochemical Services	5.1	1.8	1.8	5.6	1.3	1.3

	Summarized Income Statement Information for the Six Months Ended					
	June 30, 2009			June 30, 2008		
	Revenues	Operating Income	Net Income	Revenues	Operating Income	Net Income
NGL Pipelines & Services	$ 101.7	$ 12.8	$ 13.0	$ 142.7	$ 8.0	$ 8.3
Onshore Natural Gas Pipelines & Services	203.2	66.5	66.5	303.6	59.7	57.4
Offshore Pipelines & Services	63.2	14.5	13.7	83.1	49.5	45.2
Petrochemical Services	9.8	3.1	3.1	11.0	2.8	2.8

Note 8. Intangible Assets and Goodwill

Identifiable Intangible Assets

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

	June 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	$ (77.9)	$ 159.5	$ 237.4	$ (68.7)	$ 168.7
Contract-based intangibles	299.9	(126.8)	173.1	299.7	(117.4)	182.3
Subtotal	537.3	(204.7)	332.6	537.1	(186.1)	351.0
Onshore Natural Gas Pipelines & Services:						
Customer relationship intangibles	372.0	(113.9)	258.1	372.0	(103.2)	268.8
Contract-based intangibles	101.3	(40.9)	60.4	101.3	(36.6)	64.7
Subtotal	473.3	(154.8)	318.5	473.3	(139.8)	333.5
Offshore Pipelines & Services:						
Customer relationship intangibles	205.8	(98.2)	107.6	205.8	(90.7)	115.1
Contract-based intangibles	1.2	(0.2)	1.0	1.2	(0.1)	1.1
Subtotal	207.0	(98.4)	108.6	207.0	(90.8)	116.2
Petrochemical Services:						
Customer relationship intangibles	53.0	(11.2)	41.8	53.0	(10.5)	42.5
Contract-based intangibles	14.9	(2.9)	12.0	14.9	(2.7)	12.2
Subtotal	67.9	(14.1)	53.8	67.9	(13.2)	54.7
Total	$ 1,285.5	$ (472.0)	$ 813.5	$ 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 June 30,		For the Six Months Ended June 30,	
	2009	2008	2009	2008
NGL Pipelines & Services	$ 9.3	$ 9.8	$ 18.6	$ 19.9
Onshore Natural Gas Pipelines & Services	7.4	7.6	15.0	15.4
Offshore Pipelines & Services	3.7	4.3	7.6	8.7
Petrochemical Services	0.5	0.5	0.9	1.0
Total	$ 20.9	$ 22.2	$ 42.1	$ 45.0

Based on information currently available, we estimate that amortization expense will approximate $40.7 million for the last six months 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:

	June 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:

	June 30, 2009	December 31, 2008
EPO senior debt obligations:		
Multi-Year Revolving Credit Facility, variable rate, due November 2012	$ 853.2	$ 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	184.5	202.0
DEP Term Loan, variable rate, due December 2011	282.3	282.3
Total principal amount of senior debt obligations	8,131.5	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	9,364.2	9,046.1
Other, non-principal amounts:		
Change in fair value of debt-related derivative instruments	34.1	51.9
Unamortized discounts, net of premiums	(7.3)	(7.3)
Unamortized deferred net gains related to terminated interest rate swaps	14.7	17.7
Total other, non-principal amounts	41.5	62.3
Total debt obligations	9,405.7	9,108.4
Less current maturities of debt	(181.4)	--
Total long-term debt	$ 9,224.3	$ 9,108.4
Letters of credit outstanding	$ 111.7	$ 1.0

(1) In accordance with SFAS 6 (ASC 470), *Classification of Short-Term Obligations Expected to be Refinanced*, long-term and current maturities of debt reflect the classification of such obligations at June 30, 2009 after taking into consideration EPO's 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 June 30, 2009, EPO had outstanding a $60.0 million letter of credit relating to its commodity derivative instruments and a $50.7 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 June 30, 2009, which does reduce 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.

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.

Senior Notes P. In June 2009, EPO sold $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.

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 June 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 six months ended June 30, 2009.

	Weighted-Average Interest Rate Paid
EPO's Multi-Year Revolving Credit Facility	1.03%
DEP Revolving Credit Facility	1.89%
DEP Term Loan	1.31%
Petal GO Zone Bonds	0.91%

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	916.8
2012	1,353.2
2013	750.0
Thereafter	5,290.2
Total scheduled principal payments	$ 9,364.2

(1) Long-term and current maturities of debt reflect the classification of such obligations on our Unaudited Condensed Consolidated Balance Sheet at June 30, 2009 after taking into consideration EPO's 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 June 30, 2009, (ii) total debt of each unconsolidated affiliate at June 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%	$ 90.0	$ --	$ --	$ 90.0
Evangeline	49.5%	15.7	5.0	3.2	7.5
Total		$ 105.7	$ 5.0	$ 3.2	$ 97.5

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 June 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. In January 2009, we sold 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 universal shelf registration statement. In June 2009, EPO sold $500.0 million in principal amount of Senior Notes P under this universal shelf registration statement.

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 28,719,027 common units have been issued under this registration statement through June 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 754,159 common units have been issued to employees under this plan through June 30, 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 six months ended June 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
Total 2009	17,940,842	$ 390.6	$ 8.0	$ 398.6

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 offering	10,590,000	--	--
Common units issued in connection with DRIP and EUPP	7,350,842	--	--
Common units issued in connection with equity awards	7,500	--	--
Restricted units issued	--	1,011,350	--
Forfeiture of restricted units	--	(144,000)	--
Conversion of restricted units to common units	12,500	(12,500)	--
Acquisition of treasury units	(1,776)	--	1,776
Cancellation of treasury units	--	--	(1,776)
Balance, June 30, 2009	457,313,797	2,935,450	--

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	331.6	1.7	333.3
Operating leases paid by EPCO	0.3	--	0.3
Cash distributions to partners	(482.3)	(2.1)	(484.4)
Unit option reimbursements to EPCO	(0.3)	--	(0.3)
Net proceeds from issuance of common units	390.6	--	390.6
Proceeds from exercise of unit options	0.2	--	0.2
Amortization of equity awards	1.7	6.3	8.0
Balance, June 30, 2009	$ 6,278.7	$ 32.1	$ 6,310.8

Distributions to Partners

We paid EPGP incentive distributions of $36.6 million and $31.0 million during the three months ended June 30, 2009 and 2008, respectively. During the six months ended June 30, 2009 and 2008, we paid incentive distributions of $71.8 million and $60.8 million, respectively, to EPGP.

We paid aggregate distributions to our unitholders and our general partner of $566.4 million during the six months ended June 30, 2009. These distributions pertained to the six month period ended March 31, 2009 (i.e., the fourth quarter of 2008 and first quarter of 2009). On August 7, 2009, we will pay a quarterly cash distribution of $0.545 per unit with respect to the second quarter of 2009, to unitholders of record at the close of business on July 31, 2009.

Accumulated Other Comprehensive Loss

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

	June 30, 2009	December 31, 2008
Commodity derivative instruments (1)	$ (154.2)	$ (114.1)
Interest rate derivative instruments (1)	20.9	3.8
Foreign currency derivative instruments (1)	0.1	10.6
Foreign currency translation adjustment (2)	(0.7)	(1.3)
Pension and postretirement benefit plans	(0.7)	(0.7)
Subtotal	(134.6)	(101.7)
Amount attributable to noncontrolling interest	3.7	4.5
Total accumulated other comprehensive loss in partners' equity	$ (130.9)	$ (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:

	June 30, 2009	December 31, 2008
Limited partners of Duncan Energy Partners (1)	$ 402.6	$ 281.1
Joint venture partners (2)	111.5	112.5
AOCI attributable to noncontrolling interest	(3.7)	(4.5)
Total noncontrolling interest on consolidated balance sheets	$ 510.4	$ 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 June 30,		For the Six Months Ended June 30,	
	2009	2008	2009	2008
Limited partners of Duncan Energy Partners	$ 6.6	$ 4.8	$ 11.7	$ 9.1
Joint venture partners	6.9	4.2	13.8	12.3
Total	$ 13.5	$ 9.0	$ 25.5	$ 21.4

The following table presents distributions paid to, and 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 Six Months Ended June 30,	
	2009	2008
Distributions paid to noncontrolling interest:		
Limited partners of Duncan Energy Partners	$ 12.8	$ 12.2
Joint venture partners	15.0	16.9
Total distributions paid to noncontrolling interest	$ 27.8	$ 29.1
Contributions from noncontrolling interest:		
Limited partners of Duncan Energy Partners (1)	$ 123.2	$ --
Total contributions from noncontrolling interest (1)	$ 123.2	$ --

(1) Contributions from noncontrolling interest on the Unaudited Condensed Statements of Consolidated Equity include accruals of $0.5 million related to costs associated with Duncan Energy Partners' equity offering in June 2009.

Duncan Energy Partners issued an aggregate 8.9 million of its common units in June and July 2009, which generated net proceeds of approximately $137.7 million. Of this amount, $123.2 million had been received by June 30, 2009 (as presented in the preceding table). 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 June 30, 2009	For the Three Months Ended June 30, 2008	For the Six Months Ended June 30, 2009	For the Six Months Ended June 30, 2008
Revenues (1)	$ 3,507.9	$ 6,339.7	$ 6,931.0	$ 12,024.2
Less: Operating costs and expenses (1)	(3,134.2)	(5,960.0)	(6,175.5)	(11,271.2)
Add: Equity in income (loss) of unconsolidated affiliates (1)	(17.6)	18.6	(4.2)	33.2
Depreciation, amortization and accretion in operating costs and expenses (2)	153.2	136.3	306.7	270.2
Operating lease expense paid by EPCO (2)	0.1	0.5	0.3	1.0
Gain from asset sales and related transactions in operating costs and expenses (2)	(0.2)	(0.7)	(0.4)	(0.8)
Total segment gross operating margin	$ 509.2	$ 534.4	$ 1,057.9	$ 1,056.6

(1) These amounts are taken from our Unaudited Condensed Statements of Consolidated Operations.
(2) These non-cash expenses are taken from the operating activities section of our Unaudited Condensed Statements of Consolidated Cash Flows.

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 June 30, 2009	For the Three Months Ended June 30, 2008	For the Six Months Ended June 30, 2009	For the Six Months Ended June 30, 2008
Total segment gross operating margin	$ 509.2	$ 534.4	$ 1,057.9	$ 1,056.6
Adjustments to reconcile total segment gross operating margin to operating income:				
Depreciation, amortization and accretion in operating costs and expenses	(153.2)	(136.3)	(306.7)	(270.2)
Operating lease expense paid by EPCO	(0.1)	(0.5)	(0.3)	(1.0)
Gain from asset sales and related transactions in operating costs and expenses	0.2	0.7	0.4	0.8
General and administrative costs	(27.8)	(24.0)	(50.8)	(45.2)
Operating income	328.3	374.3	700.5	741.0
Other expense, net	(126.0)	(95.1)	(245.7)	(186.1)
Income before provision for income taxes	$ 202.3	$ 279.2	$ 454.8	$ 554.9

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 June 30, 2009	$ 2,345.9	$ 560.0	$ 76.7	$ 400.2	$ --	$ 3,382.8
Three months ended June 30, 2008	4,278.3	930.6	52.1	855.9	--	6,116.9
Six months ended June 30, 2009	4,601.2	1,160.0	145.0	655.2	--	6,561.4
Six months ended June 30, 2008	8,256.0	1,633.1	137.1	1,474.5	--	11,500.7
Revenues from related parties:						
Three months ended June 30, 2009	77.4	47.1	0.6	--	--	125.1
Three months ended June 30, 2008	117.5	102.2	3.1	--	--	222.8
Six months ended June 30, 2009	255.9	112.9	0.8	--	--	369.6
Six months ended June 30, 2008	360.4	160.0	3.1	--	--	523.5
Intersegment and intrasegment revenues:						
Three months ended June 30, 2009	1,468.2	109.6	0.3	110.6	(1,688.7)	--
Three months ended June 30, 2008	2,122.3	206.8	0.4	183.4	(2,512.9)	--
Six months ended June 30, 2009	2,824.6	258.0	0.6	207.6	(3,290.8)	--
Six months ended June 30, 2008	4,117.8	342.8	0.8	313.2	(4,774.6)	--
Total revenues:						
Three months ended June 30, 2009	3,891.5	716.7	77.6	510.8	(1,688.7)	3,507.9
Three months ended June 30, 2008	6,518.1	1,239.6	55.6	1,039.3	(2,512.9)	6,339.7
Six months ended June 30, 2009	7,681.7	1,530.9	146.4	862.8	(3,290.8)	6,931.0
Six months ended June 30, 2008	12,734.2	2,135.9	141.0	1,787.7	(4,774.6)	12,024.2
Equity in income (loss) of unconsolidated affiliates:						
Three months ended June 30, 2009	2.3	7.1	(27.4)	0.4	--	(17.6)
Three months ended June 30, 2008	1.6	5.5	11.2	0.3	--	18.6
Six months ended June 30, 2009	3.5	14.3	(22.7)	0.7	--	(4.2)
Six months ended June 30, 2008	(0.7)	11.3	21.9	0.7	--	33.2
Gross operating margin:						
Three months ended June 30, 2009	354.0	74.3	33.1	47.8	--	509.2
Three months ended June 30, 2008	317.7	123.2	35.3	58.2	--	534.4
Six months ended June 30, 2009	696.8	190.3	94.4	76.4	--	1,057.9
Six months ended June 30, 2008	607.4	233.1	116.9	99.2	--	1,056.6
Segment assets:						
At June 30, 2009	6,054.7	4,613.2	1,523.2	721.1	669.8	13,582.0
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 June 30, 2009	139.7	282.6	463.9	15.2	--	901.4
At December 31, 2008	144.2	284.0	504.8	16.5	--	949.5
Intangible assets, net: (see Note 8)						
At June 30, 2009	332.6	318.5	108.6	53.8	--	813.5
At December 31, 2008	351.0	333.5	116.2	54.7	--	855.4
Goodwill: (see Note 8)						
At June 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 June 30,		For the Six Months Ended June 30,	
	2009	2008	2009	2008
NGL Pipelines & Services:				
Sales of NGLs	$ 2,292.1	$ 4,205.6	$ 4,568.1	$ 8,256.8
Sales of other petroleum and related products	0.4	0.7	0.9	1.4
Midstream services	130.8	189.5	288.1	358.2
Total	2,423.3	4,395.8	4,857.1	8,616.4
Onshore Natural Gas Pipelines & Services:				
Sales of natural gas	497.9	899.4	1,059.6	1,541.2
Midstream services	109.2	133.4	213.3	251.9
Total	607.1	1,032.8	1,272.9	1,793.1
Offshore Pipelines & Services:				
Sales of natural gas	0.3	1.1	0.6	1.6
Sales of other petroleum and related products	0.9	4.4	1.1	7.0
Midstream services	76.1	49.7	144.1	131.6
Total	77.3	55.2	145.8	140.2
Petrochemical Services:				
Sales of other petroleum and related products	377.0	834.0	606.5	1,430.3
Midstream services	23.2	21.9	48.7	44.2
Total	400.2	855.9	655.2	1,474.5
Total consolidated revenues	$ 3,507.9	$ 6,339.7	$ 6,931.0	$ 12,024.2
Consolidated cost and expenses:				
Operating costs and expenses:				
Cost of sales for our marketing activities	$ 2,193.4	$ 4,589.0	$ 4,384.7	$ 8,707.6
Depreciation, amortization and accretion	153.2	136.3	306.7	270.2
Gain on sale of assets and related transactions	(0.2)	(0.7)	(0.4)	(0.8)
Other operating costs and expenses	787.8	1,235.4	1,484.5	2,294.2
General and administrative costs	27.8	24.0	50.8	45.2
Total consolidated costs and expenses	$ 3,162.0	$ 5,984.0	$ 6,226.3	$ 11,316.4

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 June 30, 2009	For the Three Months Ended June 30, 2008	For the Six Months Ended June 30, 2009	For the Six Months Ended June 30, 2008
Revenues from consolidated operations:				
EPCO and affiliates	$ 32.7	$ 26.3	$ 57.8	$ 44.7
Energy Transfer Equity and subsidiaries	49.2	90.3	212.0	313.4
Unconsolidated affiliates	43.2	106.2	99.8	165.4
Total	$ 125.1	$ 222.8	$ 369.6	$ 523.5
Cost of sales:				
EPCO and affiliates	$ 15.2	$ 9.8	$ 43.6	$ 25.6
Energy Transfer Equity and subsidiaries	95.9	23.3	185.9	68.8
Unconsolidated affiliates	11.4	23.9	24.5	52.2
Total	$ 122.5	$ 57.0	$ 254.0	$ 146.6
Operating costs and expenses:				
EPCO and affiliates	$ 87.0	$ 75.0	$ 166.5	$ 160.9
Energy Transfer Equity and subsidiaries	1.9	5.8	3.3	9.1
Unconsolidated affiliates	(2.5)	(2.5)	(5.2)	(4.7)
Total	$ 86.4	$ 78.3	$ 164.6	$ 165.3
General and administrative expenses:				
EPCO and affiliates	$ 16.6	$ 13.5	$ 34.4	$ 31.2
Other expense:				
EPCO and affiliates	$ --	$ --	$ --	$ 0.3

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

	June 30, 2009	December 31, 2008
Accounts receivable - related parties:		
EPCO and affiliates	$ 36.9	$ 26.6
Energy Transfer Equity and subsidiaries	5.4	35.0
Unconsolidated affiliates	5.1	--
Total	$ 47.4	$ 61.6
Accounts payable - related parties:		
EPCO and affiliates	$ 63.3	$ 39.4
Energy Transfer Equity and subsidiaries	28.9	0.2
Unconsolidated affiliates	3.8	--
Total	$ 96.0	$ 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 owned and/or controlled by Enterprise GP Holdings; 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 June 30, 2009, EPCO and its affiliates beneficially owned 158,930,186 (or 34.5%) of our outstanding common units, which includes 13,670,925 of our common units owned by Enterprise GP Holdings. In addition, at June 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 $81.7 million and $69.7 million from us during the six months ended June 30, 2009 and 2008, respectively. These amounts include incentive distributions of $71.8 million and $60.8 million for the six months ended June 30, 2009 and 2008, respectively.

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 $230.3 million and $197.5 million in cash distributions during the six months ended June 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 $90.7 million for operating costs and expenses and $16.6 million for general and administrative costs for the three months ended June 30, 2009. For the six months ended June 30, 2009, we reimbursed EPCO $173.8 million for operating costs and expenses and $34.4 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.

We received $32.7 million and $26.3 million from TEPPCO for the three months ended June 30, 2009 and 2008, respectively, from the sale of hydrocarbon products. For the six months ended June 30, 2009 and 2008, we received $57.8 million and $44.7 million from TEPPCO, respectively, from the sale of hydrocarbon products. We paid TEPPCO $11.3 million and $4.6 million for NGL pipeline transportation and storage services during the three months ended June 30, 2009 and 2008, respectively. During the six months ended June 30, 2009 and 2008, we paid TEPPCO $36.0 million and $15.9 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 June 30, 2009 was $250.4 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 Note 7).

Proposed Merger of TEPPCO and TEPPCO GP with Enterprise Products Partners. On June 28, 2009, we, EPGP and two of our subsidiaries entered into definitive merger agreements with TEPPCO and TEPPCO GP. Under the terms of the definitive agreements, TEPPCO and TEPPCO GP would become our wholly owned subsidiaries and each of TEPPCO's unitholders, except for a certain privately-held affiliate of EPCO, would receive 1.24 of our common units for each TEPPCO unit. A privately-held affiliate of EPCO would exchange its 11,486,711 TEPPCO units for 14,243,521 of our limited partner units, based on the 1.24 exchange rate, consisting of 9,723,090 of our common units and 4,520,431 of our Class B units. The Class B units will not be entitled to regular quarterly cash distributions for sixteen quarters following the closing of the merger. The Class B units would convert automatically into the same number of common units on the date immediately following the payment date for the sixteenth quarterly distribution following the closing of the merger. The Class B units will be entitled to vote together with the common units as a single class on partnership matters and, except for the payment of distributions, will have the same rights and privileges as our common units. No fractional common units would be issued in the proposed merger, and TEPPCO unitholders would, instead, receive cash in lieu of fractional common units, if any.

Under the terms of the definitive agreements, Enterprise GP Holdings would receive 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. The respective ACG Committees of EPGP and Enterprise GP Holdings each voted unanimously to approve the merger and a Special Committee of the ACG Committee of TEPPCO GP voted unanimously to recommend the merger.

Following the closing of the proposed merger, we expect affiliates of EPCO would own approximately 29.5% of our outstanding limited partner units, including 3.4% owned by Enterprise GP Holdings.

Completion of the proposed merger is subject to the approval of holders of at least a majority of the outstanding TEPPCO units. In addition, pursuant to the merger agreement providing for the merger of TEPPCO, the number of votes cast in favor of the merger agreement by TEPPCO's unitholders (excluding specified unitholders affiliated with EPCO and other specified officers and directors of TEPPCO GP, Enterprise GP Holdings and us) must exceed the number of votes actually cast against the merger agreement by such unaffiliated TEPPCO unitholders. Affiliates of EPCO, including Enterprise GP Holdings, have executed a support agreement in which they have agreed to vote their units in favor of the merger agreement and in which Enterprise GP Holdings acknowledges and agrees that it has executed a written consent as the sole member of TEPPCO GP approving the merger agreement to merge TEPPCO GP with us. The closing is also subject to customary regulatory approvals, including those under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended. Subject to the receipt of regulatory and TEPPCO unitholder approvals, completion of the proposed merger is expected to occur during the fourth quarter of 2009. See Note 14 for information regarding litigation matters associated with the proposed merger.

The merger agreement providing for the merger of TEPPCO contains provisions granting both TEPPCO and us the right to terminate the agreement for certain reasons, including, among others, (i) if TEPPCO's merger into our subsidiary has not occurred on or before December 31, 2009 and (ii) TEPPCO's failure to obtain unitholder approval as described above.

We incurred $4.3 million of merger-related expenses during the second quarter of 2009 that are reflected as a component of general and administrative costs.

Loan Agreement with TEPPCO. On August 5, 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. See Note 18 for additional information regarding this Loan Agreement.

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 $49.2 million and $90.3 million, respectively, of revenues from Energy Transfer Partners, L.P. ("ETP"), primarily from NGL marketing activities for the three months ended June 30, 2009 and 2008. For the six months ended June 30, 2009 and 2008, we recorded $212.0 million and $313.4 million, respectively, of revenues from ETP, primarily from NGL marketing activities. We incurred $97.8 million and $29.1 million for the three months ended June 30, 2009 and 2008, respectively, in costs of sales and operating costs and expenses. For the six months ended June 30, 2009 and 2008, we incurred $189.2 million and $77.9 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 June 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 June 30, 2009, EPO beneficially owned approximately 61% 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 8.9 million of its common units in June and July 2009, which generated net proceeds of approximately $137.7 million ($123.2 million of which had been received as of June 30, 2009). 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. At August 1, 2009, EPO beneficially owned approximately 58% of Duncan Energy Partners' limited partner interests and 100% of its general partner.

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 $36.7 million in connection with the Omnibus Agreement during the six months ended June 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 $12.7 million and $68.1 million under the Mont Belvieu Caverns limited liability company agreement during the six months ended June 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 $22.4 million to fund such projects in 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 $665.4 million at June 30, 2009. The Enterprise III Distribution Base was unchanged at $730.0 million at June 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 June 30, 2009	For the Three Months Ended June 30, 2008	For the Six Months Ended June 30, 2009	For the Six Months Ended June 30, 2008
Net income attributable to Enterprise Products Partners L.P.	$ 186.6	$ 263.3	$ 411.9	$ 522.9
Less incentive earnings allocations to EPGP	(36.6)	(31.0)	(71.8)	(60.8)
Net income available after incentive earnings allocation	150.0	232.3	340.1	462.1
Multiplied by EPGP ownership interest	2.0%	2.0%	2.0%	2.0%
Standard earnings allocation to EPGP	$ 3.0	$ 4.6	$ 6.8	$ 9.2
Incentive earnings allocation to EPGP	$ 36.6	$ 31.0	$ 71.8	$ 60.8
Standard earnings allocation to EPGP	3.0	4.6	6.8	9.2
Net income available to EPGP	39.6	35.6	78.6	70.0
Adjustment for EITF 07-4 (1)	1.4	1.1	2.8	2.2
Net income available to EPGP for EPU purposes	$ 41.0	$ 36.7	$ 81.4	$ 72.2

(1) For purposes of computing basic and diluted earnings per unit, we apply the provisions of EITF 07-4.

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

	For the Three Month Ended June 30, 2009	For the Three Month Ended June 30, 2008	For the Six Month Ended June 30, 2009	For the Six Month Ended June 30, 2008
BASIC EARNINGS PER UNIT				
Numerator				
Net income attributable to Enterprise Products Partners L.P.	$ 186.6	$ 263.3	$ 411.9	$ 522.9
Net income available to EPGP for EPU purposes	(41.0)	(36.7)	(81.4)	(72.2)
Net income available to limited partners	$ 145.6	$ 226.6	$ 330.5	$ 450.7
Denominator				
Weighted – average common units	455.8	434.6	453.3	434.3
Weighted – average time-vested restricted units	2.6	1.9	2.2	1.8
Total	458.4	436.5	455.5	436.1
Basic earnings per unit				
Net income per unit before EPGP earnings allocation	$ 0.41	$ 0.60	$ 0.91	$ 1.20
Net income available to EPGP	(0.09)	(0.08)	(0.18)	(0.17)
Net income available to limited partners	$ 0.32	$ 0.52	$ 0.73	$ 1.03
DILUTED EARNINGS PER UNIT				
Numerator				
Net income attributable to Enterprise Products Partners L.P.	$ 186.6	$ 263.3	$ 411.9	$ 522.9
Net income available to EPGP for EPU purposes	(41.0)	(36.7)	(81.4)	(72.2)
Net income available to limited partners	$ 145.6	$ 226.6	$ 330.5	$ 450.7
Denominator				
Weighted – average common units	455.8	434.6	453.3	434.3
Weighted – average time-vested restricted units	2.6	1.9	2.2	1.8
Incremental option units	0.1	0.3	0.1	0.3
Total	458.5	436.8	455.6	436.4
Diluted earnings per unit				
Net income per unit before EPGP earnings allocation	$ 0.41	$ 0.60	$ 0.91	$ 1.20
Net income available to EPGP	(0.09)	(0.08)	(0.18)	(0.17)
Net income available to limited partners	$ 0.32	$ 0.52	$ 0.73	$ 1.03

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 proposed merger of TEPPCO and TEPPCO GP with us. 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 proposed 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 proposed 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 proposed merger, (ii) rescinding the proposed 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 purposed 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 contemplates that the parties will 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 will recommend to TEPPCO's unitholders that they approve the adoption of the merger agreement and take all necessary steps to seek unitholder approval for the merger as soon as practicable. Pursuant to the Settlement Agreement, approval of the merger will require, 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. 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 proposed 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 proposed merger and (iv) final Delaware Court certification and approval of the settlement and dismissal of the actions. See Note 12 for additional information regarding our relationship with TEPPCO, including information related to the proposed 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 proposed merger of TEPPCO with us. 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.

On February 14, 2007, EPO received a letter from the Environment and Natural Resources Division ("ENRD") of the U.S. Department of Justice ("DOJ") related to an ammonia release in Kingman County, Kansas on October 27, 2004 from a pressurized anhydrous ammonia pipeline ("Magellan 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. The ENRD has indicated that it may pursue civil damages against EPO and Magellan as a result of these incidents. Based on this correspondence from the ENRD, the statutory maximum amount of civil fines that could be assessed against EPO and Magellan is up to $17.4 million in the aggregate. EPO is cooperating with the DOJ and is hopeful that an expeditious resolution of this civil matter acceptable to all parties will be reached in the near future. Magellan has agreed to indemnify EPO for the civil matter. At this time, we do not believe that a final resolution of the civil claims by the ENRD will have a material impact on our consolidated financial position, results of operations or cash flows.

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. The State's complaint also seeks penalties for the above alleged failures. Defendants and the State agreed to certain stipulations that, among other things, require us to install specified environmental protection measures in the disturbed pipeline right-of-way to comply with regulations. We have complied with the stipulations and the State has dismissed the portions of the complaint seeking the temporary restraining order and injunction. We have entered into a settlement agreement with the State that assesses a fine of which we are responsible for 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 believes there has been no adverse impact to public health or the environment, having implemented voluntary emission reduction measures over the years. The State seeks penalties above $100,000. 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 has 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. Since we believe that our actions in dissociating from TOPS are expressly permitted by, and in accordance with, the terms of the TOPS partnership agreement, we intend to vigorously defend such actions. We have not recorded any reserves for potential liabilities relating to this litigation, although we may determine in future periods that an accrual of reserves for potential liabilities (including costs of litigation) should be made. If these payments are substantial, we could experience a material adverse impact on our results of operations and our liquidity.

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. With the exception of the issuance of Senior Notes P and routine fluctuations in the balance of our consolidated revolving credit facilities, there have been no significant changes in our consolidated scheduled maturities of long-term debt since those reported in our Recast Form 8-K. See Note 9 for additional information regarding our 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 incremental 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 during 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 $10.1 million and $9.4 million during the three months ended June 30, 2009 and 2008, respectively. For the six months ended June 30, 2009 and 2008, lease and rental expense was $19.6 million and $18.4 million, respectively.

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

Due to our dissociation from TOPS, our 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 our dissociation from 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 June 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 remained unchanged 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 allocated share of EPCO's insurance deductibles for windstorm coverage, we expensed a combined cumulative total of $47.4 million of repair costs for property damage in connection with these two storms through June 30, 2009. We continue to file property damage claims in connection with the damage caused by these storms. The insurance carriers have notified us that they expect to pay us an initial $25.0 million in business interruption proceeds during the third quarter of 2009 in connection with 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 Six Months Ended June 30,	
	2009 (1)	**2008** (1)
Business interruption proceeds:		
Hurricane Katrina	$ --	$ 0.5
Hurricane Rita	--	0.7
Total business interruption proceeds	--	1.2
Property damage proceeds:		
Hurricane Katrina	23.2	6.9
Hurricane Rita	--	2.7
Total property damage proceeds	23.2	9.6
Total	$ 23.2	$ 10.8

(1) No such proceeds were received during the three months ended June 30, 2009 and 2008.

At June 30, 2009, we have $14.1 million of estimated property damage claims outstanding related to storms that we believe are probable of collection during the next twelve months and $55.7 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. Since LBI filed for Chapter 11 bankruptcy protection and with the support of debtor-in-possession financing, it continues to do business with us. However, we have taken steps to manage our credit exposure to LBI through prepayment requirements and similar remedies. Based on current facts known to us, the bankruptcy of LBI is not expected to have a material adverse effect on our revenues, results of operations or financial condition.

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 Six Months Ended June 30,	
	2009	2008
Decrease (increase) in:		
Accounts and notes receivable – trade	$ (47.1)	$ (590.8)
Accounts receivable – related parties	27.8	26.0
Inventories	(616.3)	(109.9)
Prepaid and other current assets	(32.6)	(41.5)
Other assets	(29.0)	(5.0)
Increase (decrease) in:		
Accounts payable – trade	(21.6)	30.6
Accounts payable – related parties	57.2	37.3
Accrued product payables	387.7	475.9
Accrued interest payable	19.9	8.5
Other accrued expenses	(16.4)	17.2
Other current liabilities	(71.0)	(1.9)
Other liabilities	(3.8)	(3.3)
Net effect of changes in operating accounts	$ (345.2)	$ (156.9)

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:

	June 30, 2009	December 31, 2008
ASSETS		
Current assets	$ 2,867.6	$ 2,175.6
Property, plant and equipment, net	13,582.0	13,154.8
Investments in unconsolidated affiliates, net	901.4	949.5
Intangible assets, net	813.5	855.4
Goodwill	706.9	706.9
Other assets	149.1	126.6
Total	$ 19,020.5	$ 17,968.8
LIABILITIES AND EQUITY		
Current liabilities	$ 2,807.4	$ 2,222.7
Long-term debt	9,224.3	9,108.4
Other long-term liabilities	167.8	147.3
Equity	6,821.0	6,490.4
Total	$ 19,020.5	$ 17,968.8
Total EPO debt obligations guaranteed by Enterprise Products Partners L.P.	$ 8,897.4	$ 8,561.8

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2009	2008	2009	2008
Revenues	$ 3,507.9	$ 6,339.7	$ 6,931.0	$ 12,024.2
Costs and expenses	3,157.5	5,983.3	6,219.8	11,315.1
Equity in income (loss) of unconsolidated affiliates	(17.6)	18.6	(4.2)	33.2
Operating income	332.8	375.0	707.0	742.3
Other expense	(126.1)	(95.1)	(245.7)	(186.2)
Income before provision for income taxes	206.7	279.9	461.3	556.1
Provision for income taxes	(2.2)	(6.9)	(17.4)	(10.6)
Net income	204.5	273.0	443.9	545.5
Net income attributable to the noncontrolling interest	(13.6)	(9.0)	(25.7)	(21.4)
Net income attributable to EPO	$ 190.9	$ 264.0	$ 418.2	$ 524.1

Note 18. Subsequent Events

Loan Agreement with TEPPCO

On August 5, 2009, EPO entered into a 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. Borrowings under the Loan Agreement mature on the earliest to occur of (i) the consummation of our proposed merger with TEPPCO, (ii) the termination of the related merger agreement in accordance with the provisions thereof, (iii) December 31, 2009, (iv) the date upon which the maturity of the loan is otherwise accelerated upon an event of default, and (v) the date upon which EPO's commitment to make the loan is terminated by TEPPCO pursuant to the Loan Agreement. Borrowings under the Loan Agreement will bear interest at a floating rate equivalent to the one-month LIBOR Rate (as defined in the Loan Agreement) plus 2%. Interest is payable monthly.

The Loan Agreement provides that amounts borrowed are non-recourse to TEPPCO GP and TEPPCO's limited partners. The Loan Agreement contains customary events of default, including (i) nonpayment of principal when due or nonpayment of interest or other amounts within three business days of when due, (ii) bankruptcy or insolvency with respect to TEPPCO, (iii) a change of control, or (iv) an event of default under TEPPCO's revolving credit facility. Any amounts due by TEPPCO under the Loan Agreement will be unconditionally and irrevocably guaranteed by each TEPPCO subsidiary that guarantees TEPPCO's obligations under its revolving credit facility. EPO's obligation to fund any borrowings under the Loan Agreement is subject to specified conditions, including the condition that, on and as of the applicable date of funding, no additional amounts are available to TEPPCO pursuant to TEPPCO's revolving credit facility (either as borrowings or under any letters of credit).

The execution of the Loan Agreement was unanimously approved by the ACG Committees of EPGP and TEPPCO GP.

Settlement Agreement

On August 5, 2009, the parties to the Merger Action and the Derivative Action described in Note 14 entered into the Settlement Agreement contemplated by the Memorandum of Understanding. Pursuant to the Settlement Agreement, the board of directors of TEPPCO GP will recommend to TEPPCO's unitholders that they approve the adoption of the merger agreement governing TEPPCO's proposed merger with a subsidiary of ours and take all necessary steps to seek unitholder approval for the merger as soon as practicable. Pursuant to the Settlement Agreement, approval of the merger will require, 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'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. 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. See Note 12 for additional information regarding our relationship with TEPPCO, including information related to the proposed merger. See Note 14 for additional information related to the Merger Action and the Derivative Action, including the Settlement Agreement.

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

For the three and six months ended June 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 retrospectively adjusted portions of our Annual Report for the year ended December 31, 2008. The Recast Form 8-K reflects our adoption of Statement of Financial Accounting Standards ("SFAS") 160 (Accounting Standards Codification ("ASC") 810), *Noncontrolling Interests in Consolidated Financial Statements – an amendment of ARB No. 51* and Emerging Issues Task Force ("EITF") 07-4 (ASC 260), *Application of the Two Class Method Under FASB Statement No. 128 to Master Limited Partnerships*, 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" mean TEPPCO Partners, L.P., a publicly traded limited partnership, the common units of which are listed on the NYSE under the ticker symbol "TPP." References to "TEPPCO GP" refer to Texas Eastern Products Pipeline Company, LLC, which is the general partner of TEPPCO and is wholly owned by Enterprise GP Holdings. On June 28, 2009, we and TEPPCO (including TEPPCO GP) entered into definitive agreements to merge. For additional information regarding the merger agreements, 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. ("ETP"). 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 "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, Inc.

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 and in Part II, Item 1A of our Quarterly Report on Form 10-Q for the quarter ended March 31, 2009 and this Quarterly Report. 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.

Proposed Merger of TEPPCO and TEPPCO GP with Enterprise Products Partners

On June 28, 2009, we, EPGP and two of our subsidiaries entered into definitive merger agreements with TEPPCO and TEPPCO GP. Under the terms of the definitive agreements, TEPPCO and TEPPCO GP would become our wholly owned subsidiaries and each of TEPPCO's unitholders, except for a certain privately-held affiliate of EPCO, would receive 1.24 of our common units for each TEPPCO unit. A privately-held affiliate of EPCO would exchange its 11,486,711 TEPPCO units for 14,243,521 of our limited partner units, based on the 1.24 exchange rate, consisting of 9,723,090 of our common units and 4,520,431 of our Class B units. The Class B units will not be entitled to regular quarterly cash distributions for sixteen quarters following the closing of the merger. The Class B units would convert automatically into the same number of common units on the date immediately following the payment date for the sixteenth quarterly distribution following the closing of the merger. The Class B units will be entitled to vote together with the common units as a single class on partnership matters and, except for the payment of distributions, will have the same rights and privileges as our common units. No fractional common units would be issued in the proposed merger, and TEPPCO unitholders would, instead, receive cash in lieu of fractional common units, if any.

Under the terms of the definitive agreements, Enterprise GP Holdings would receive 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. The respective Audit, Conflicts and Governance ("ACG") Committees of EPGP and Enterprise GP Holdings each voted unanimously to approve the merger and a Special Committee of the ACG Committee of TEPPCO GP voted unanimously to recommend the merger.

Following the closing of the proposed merger, we expect affiliates of EPCO would own approximately 29.5% of our outstanding limited partner units, including 3.4% owned by Enterprise GP Holdings.

Completion of the proposed merger is subject to the approval of holders of at least a majority of the outstanding TEPPCO units. In addition, pursuant to the merger agreement providing for the merger of TEPPCO, the number of votes cast in favor of the merger agreement by TEPPCO's unitholders (excluding specified unitholders affiliated with EPCO and other specified officers and directors of TEPPCO GP, Enterprise GP Holdings and us) must exceed the number of votes actually cast against the merger agreement by such unaffiliated TEPPCO unitholders. Affiliates of EPCO, including Enterprise GP Holdings, have executed a support agreement in which they have agreed to vote their units in favor of the merger agreement and in which Enterprise GP Holdings acknowledges and agrees that it has executed a written consent as the sole member of TEPPCO GP approving the merger agreement to merge TEPPCO GP with us. The closing is also subject to customary regulatory approvals, including those under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended. Subject to the receipt of regulatory and TEPPCO unitholder approvals, completion of the proposed merger is expected to occur during the fourth quarter of 2009. See Note 14 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report for information regarding litigation matters associated with the proposed merger.

The merger agreement providing for the merger of TEPPCO contains provisions granting both TEPPCO and us the right to terminate the agreement for certain reasons, including, among others, (i) if TEPPCO's merger into our subsidiary has not occurred on or before December 31, 2009 and (ii) TEPPCO's failure to obtain unitholder approval as described above.

Loan Agreement with TEPPCO. On August 5, 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. Borrowings under the Loan Agreement mature on the earliest to occur of (i) the consummation of our proposed merger with TEPPCO, (ii) the termination of the related merger agreement in accordance with the provisions thereof, (iii) December 31, 2009, (iv) the date upon which the maturity of the loan is otherwise accelerated upon an event of default, and (v) the date upon which EPO's commitment to make the loan is terminated by TEPPCO pursuant to the Loan Agreement. Borrowings under the Loan Agreement will bear interest at a floating rate equivalent to the one-month LIBOR Rate (as defined in the Loan Agreement) plus 2%. Interest is payable monthly.

The Loan Agreement provides that amounts borrowed are non-recourse to TEPPCO GP and TEPPCO's limited partners. The Loan Agreement contains customary events of default, including (i) nonpayment of principal when due or nonpayment of interest or other amounts within three business days of when due, (ii) bankruptcy or insolvency with respect to TEPPCO, (iii) a change of control, or (iv) an event of default under TEPPCO's revolving credit facility. Any amounts due by TEPPCO under the Loan Agreement will be unconditionally and irrevocably guaranteed by each TEPPCO subsidiary that guarantees TEPPCO's obligations under its revolving credit facility. EPO's obligation to fund any borrowings under the Loan Agreement is subject to specified conditions, including the condition that, on and as of the applicable date of funding, no additional amounts are available to TEPPCO pursuant to TEPPCO's revolving credit facility (either as borrowings or under any letters of credit).

The execution of the Loan Agreement was unanimously approved by the ACG Committees of EPGP and TEPPCO GP.

Settlement Agreement. On August 5, 2009, the parties to the Merger Action and the Derivative Action described in Note 14 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report 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 will recommend to TEPPCO's unitholders that they approve the adoption of the merger agreement governing TEPPCO's proposed merger with a subsidiary of ours and take all necessary steps to seek unitholder approval for the merger as soon as practicable. Pursuant to the Settlement Agreement, approval of the merger will require, 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'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. 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. See Note 12 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report for additional information regarding our relationship with TEPPCO, including information related to the proposed merger. See Note 14 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report for additional information related to the Merger Action and the Derivative Action, including the Settlement Agreement.

Duncan Energy Partners' Equity Offering

In June 2009, Duncan Energy Partners completed a common unit offering of 8,000,000 units that generated net proceeds of approximately $123.2 million after underwriting discounts and other expenses. 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. The total net proceeds from this offering were used to repurchase an equal number of common units of Duncan Energy Partners beneficially owned by EPO. The repurchased common units were subsequently cancelled.

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 sold $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 to (i) 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 in loss of unconsolidated affiliates and net income for the second quarter of 2009 reflect a non-cash charge of $34.2 million. This loss represents our cumulative investment in TOPS through the date of dissociation and reflects our capital contributions to TOPS for construction in progress amounts. We believe that the dissociation discharged our affiliate with respect to further obligations under the TOPS partnership agreement, and accordingly, us from the associated liability under the related parent guarantee; therefore, we have not recorded any amounts related to such guarantee. The wholly owned subsidiary of TEPPCO that was a partner in TOPS also dissociated from the partnership effective April 16, 2009. 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 has 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.

Since being placed in service, the Sherman Extension has been 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; however, due to price location differentials, we are currently flowing approximately 650 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, $/MMBtu	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
2009 Averages	$4.21	$51.25	$0.39	$0.70	$0.90	$1.04	$1.09	$0.30	$ 0.24

(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 June 30,		For the Six Months Ended June 30,	
	2009	2008	2009	2008
NGL Pipelines & Services, net:				
NGL transportation volumes (MBPD)	1,799	1,776	1,866	1,803
NGL fractionation volumes (MBPD)	449	436	440	430
Equity NGL production (MBPD)	118	111	116	107
Fee-based natural gas processing (MMcf/d)	2,714	2,677	2,908	2,673
Onshore Natural Gas Pipelines & Services, net:				
Natural gas transportation volumes (BBtus/d)	8,256	7,395	8,120	7,188
Offshore Pipelines & Services, net:				
Natural gas transportation volumes (BBtus/d)	1,460	1,170	1,501	1,553
Crude oil transportation volumes (MBPD)	244	216	219	211
Platform natural gas processing (MMcf/d)	765	353	771	591
Platform crude oil processing (MBPD)	10	22	7	21
Petrochemical Services, net:				
Butane isomerization volumes (MBPD)	100	89	95	92
Propylene fractionation volumes (MBPD)	67	61	67	60
Octane additive production volumes (MBPD)	10	11	7	9
Petrochemical transportation volumes (MBPD)	110	119	108	117
Total, net:				
NGL, crude oil and petrochemical transportation volumes (MBPD)	2,153	2,111	2,193	2,131
Natural gas transportation volumes (BBtus/d)	9,716	8,565	9,621	8,741
Equivalent transportation volumes (MBPD) (1)	4,710	4,365	4,725	4,431

(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 June 30,		For the Six Months Ended June 30,	
	2009	2008	2009	2008
Revenues	$ 3,507.9	$ 6,339.7	$ 6,931.0	$ 12,024.2
Operating costs and expenses	3,134.2	5,960.0	6,175.5	11,271.2
General and administrative costs	27.8	24.0	50.8	45.2
Equity in income (loss) of unconsolidated affiliates	(17.6)	18.6	(4.2)	33.2
Operating income	328.3	374.3	700.5	741.0
Interest expense	126.2	95.8	246.6	187.7
Provision for income taxes	2.2	6.9	17.4	10.6
Net income	200.1	272.3	437.4	544.3
Net income attributable to noncontrolling interest	13.5	9.0	25.5	21.4
Net income attributable to Enterprise Products Partners L.P.	186.6	263.3	411.9	522.9

Effective January 1, 2009, we adopted the provisions of SFAS 160 (ASC 810), *Noncontrolling Interests in Consolidated Financial Statements – an amendment of ARB No. 51*. SFAS 160 established accounting and reporting standards for noncontrolling interests, which were previously identified as minority interest in our financial statements. This new standard 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 to be allocated between controlling and noncontrolling interest.   Earnings per unit amounts are not affected by these changes.

The consolidated financial statements included in this Quarterly Report have been retrospectively adjusted to reflect the changes required by SFAS 160. As a result, net income reported for the three and six months ended June 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. For information regarding noncontrolling interest, see Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report.

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 June 30,		**For the Six Months Ended June 30,**	
	2009	**2008**	**2009**	**2008**
Gross operating margin by segment:				
NGL Pipelines & Services	$ 354.0	$ 317.7	$ 696.8	$ 607.4
Onshore Natural Gas Pipelines & Services	74.3	123.2	190.3	233.1
Offshore Pipeline & Services	33.1	35.3	94.4	116.9
Petrochemical Services	47.8	58.2	76.4	99.2
Total segment gross operating margin	$ 509.2	$ 534.4	$ 1,057.9	$ 1,056.6

For a reconciliation of non-GAAP gross operating margin to GAAP operating income and further to GAAP 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 June 30,		For the Six Months Ended June 30,	
	2009	2008	2009	2008
NGL Pipelines & Services:				
Sales of NGLs	$ 2,292.1	$ 4,205.6	$ 4,568.1	$ 8,256.8
Sales of other petroleum and related products	0.4	0.7	0.9	1.4
Midstream services	130.8	189.5	288.1	358.2
Total	2,423.3	4,395.8	4,857.1	8,616.4
Onshore Natural Gas Pipelines & Services:				
Sales of natural gas	497.9	899.4	1,059.6	1,541.2
Midstream services	109.2	133.4	213.3	251.9
Total	607.1	1,032.8	1,272.9	1,793.1
Offshore Pipelines & Services:				
Sales of natural gas	0.3	1.1	0.6	1.6
Sales of other petroleum and related products	0.9	4.4	1.1	7.0
Midstream services	76.1	49.7	144.1	131.6
Total	77.3	55.2	145.8	140.2
Petrochemical Services:				
Sales of other petroleum and related products	377.0	834.0	606.5	1,430.3
Midstream services	23.2	21.9	48.7	44.2
Total	400.2	855.9	655.2	1,474.5
Total consolidated revenues	$ 3,507.9	$ 6,339.7	$ 6,931.0	$ 12,024.2

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

Revenues for the second quarter of 2009 were $3.51 billion compared to $6.34 billion for the second quarter of 2008. The $2.83 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 second quarter of 2009 relative to the second quarter of 2008.

Operating costs and expenses were $3.13 billion for the second quarter of 2009 versus $5.96 billion for the second quarter of 2008, a $2.83 billion quarter-to-quarter decrease. The cost of sales of our marketing activities decreased $2.40 billion quarter-to-quarter primarily due to lower energy commodity prices. Likewise, the operating costs and expenses of our natural gas processing plants decreased $353.9 million quarter-to-quarter primarily due to lower plant thermal reduction (i.e., PTR) costs attributable to the decline in energy commodity prices. General and administrative costs increased $3.8 million quarter-to-quarter primarily due to expenses we incurred during the second quarter of 2009 in connection with the proposed merger of Enterprise Products Partners with TEPPCO and TEPPCO GP.

Changes in our revenues and costs and expenses quarter-to-quarter are primarily explained by changes in energy commodity prices. The weighted-average indicative market price for NGLs was $0.76 per gallon during the second quarter of 2009 versus $1.70 per gallon during the second quarter of 2008 – a 55% 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) decreased 68% quarter-to-quarter to an average of $3.51 per MMBtu during the second quarter of 2009 versus $10.94 per MMBtu during the second 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 (loss) from our unconsolidated affiliates was a loss of $17.6 million for the second quarter of 2009 compared to earnings of $18.6 million for the second quarter of 2008, a $36.2 million quarter-to-quarter decrease. In April 2009, our wholly owned subsidiary elected to dissociate from

TOPS. As a result, we recorded a $34.2 million non-cash charge in equity in loss of unconsolidated affiliates during the second quarter of 2009. For additional information regarding our dissociation from TOPS, see “Recent Developments” included within this Item 2. 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 $1.1 million and $0.8 million, respectively, for the second 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. Collectively, equity in income from our other equity investments decreased $3.9 million quarter-to-quarter primarily due to the expiration of demand fee revenues on our Marco Polo platform during the second quarter of 2009, which is owned through our investment in Deepwater Gateway, L.L.C., and reduced volumes on the Cameron Highway crude oil pipeline due to the lingering effects of Hurricanes Gustav and Ike.

Operating income for the second quarter of 2009 was $328.3 million compared to $374.3 million for the second quarter of 2008. Consolidated revenues and certain operating costs and expenses can fluctuate significantly due to changes in energy commodity prices (e.g., the price of natural gas and NGLs) without necessarily affecting our operating income to the same degree. Consequently, the aforementioned changes in revenues, costs and expenses and equity in loss of unconsolidated affiliates contributed to the $46.0 million quarter-to-quarter decrease in operating income.

Interest expense increased to $126.2 million for the second quarter of 2009 from $95.8 million for the second quarter of 2008. The $30.4 million quarter-to-quarter increase in interest expense is primarily due to our issuance of Senior Notes O in the fourth quarter of 2008 and a $12.0 million decrease in capitalized interest during the second quarter of 2009 relative to the second quarter of 2008. Average debt principal increased during the second quarter of 2009 to $9.40 billion from $7.60 billion during the second quarter of 2008 primarily due to debt incurred to fund growth capital investments. Provision for income taxes decreased $4.7 million quarter-to-quarter primarily due to lower accruals for the Texas Margin Tax.

As a result of items noted in the previous paragraphs, net income decreased $72.2 million quarter-to-quarter to $200.1 million for the second quarter of 2009 compared to $272.3 million for the second quarter of 2008. Net income attributable to noncontrolling interests was $13.5 million for the second quarter of 2009 compared to $9.0 million for the second quarter of 2008. Net income attributable to Enterprise Products Partners decreased $76.7 million quarter-to-quarter to $186.6 million for the second quarter of 2009 compared to $263.3 million for the second quarter of 2008.

We estimate that gross operating margin was reduced by approximately $12.0 million during the second quarter of 2009 due to the lingering effects of Hurricanes Gustav and Ike, which resulted in continued producer supply interruptions and facility downtime. For more information regarding our insurance program and claims related to these storms, see “Other Items – Weather-Related Risks” 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 $354.0 million for the second quarter of 2009 compared to $317.7 million for the second quarter of 2008, a $36.3 million quarter-to-quarter increase. In general, this business segment benefited from a quarter-to-quarter increase in gross operating margin from our Rocky Mountain natural gas processing plants and related hedging program, improved results from our NGL marketing activities and lower fuel costs during the second quarter of 2009 compared to the second quarter of 2008.

Gross operating margin from our natural gas processing and related NGL marketing business was $219.4 million for the second quarter of 2009 compared to $196.5 million for the second quarter of 2008. Equity NGL production increased to 118 MBPD during the second quarter of 2009 from 111 MBPD during the second quarter of 2008. The $22.9 million quarter-to-quarter increase in gross operating margin from this business is attributable to our Rocky Mountain natural gas processing facilities and related hedging program and 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 $98.1 million for the second quarter of 2009 compared to $94.2 million for the second quarter of 2008, a $3.9 million quarter-to-quarter increase. Gross operating margin from our Mont Belvieu Storage complex increased $8.9 million quarter-to-quarter primarily due to increased volumes and fees. Gross operating margin from our Mid-America and Seminole Pipeline Systems decreased $7.5 million quarter-to-quarter primarily due to acquisition-related settlements that we recorded during the second quarter of 2008. Collectively, gross operating margin from the remainder of our NGL pipeline and storage assets increased $2.5 million quarter-to-quarter largely due to higher NGL export activity, improved results from our assets in south Louisiana and lower fuel costs during the second quarter of 2009, partially offset by higher pipeline integrity expenses on our Dixie pipeline and lower NGL import volumes. Total NGL transportation volumes increased to 1,799 MBPD during the second quarter of 2009 from 1,776 MBPD during the second quarter of 2008.

Gross operating margin from our NGL fractionation business was $36.5 million for the second quarter of 2009 compared to $26.9 million for the second quarter of 2008. Fractionation volumes increased to 449 MBPD during the second quarter of 2009 from 436 MBPD during the second quarter of 2008. The $9.6 million quarter-to-quarter increase in gross operating margin from this business is primarily due to increased fractionation volumes and lower fuel costs at our Mont Belvieu and Norco fractionators during the second quarter of 2009 relative to the second quarter of 2008.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $74.3 million for the second quarter of 2009 compared to $123.2 million for the second quarter of 2008, a $48.9 million quarter-to-quarter decrease. Our onshore natural gas transportation volumes were 8,256 BBtus/d during the second quarter of 2009 compared to 7,395 BBtus/d during the second quarter of 2008.

Gross operating margin from our onshore natural gas pipeline and related natural gas marketing business was $61.9 million for the second quarter of 2009 compared to $115.4 million for the second quarter of 2008. The $53.5 million quarter-to-quarter decrease in gross operating margin from this business is largely due to lower revenues earned by our San Juan gathering system from fees indexed to regional natural gas prices, lower condensate sales revenues as a result of a quarter-to-quarter decrease in commodity prices and lower natural gas sales volumes and margins on our Acadian Gas System.

We completed the Sherman Extension expansion of our Texas Intrastate System in late February 2009 adding an incremental 1.1 Bcf/d of natural gas throughput capacity. However, the Sherman Extension has been in very limited service due to pipeline integrity issues on the connecting take-away pipeline, the Gulf Crossing Pipeline owned by Boardwalk. On August 1, 2009, the Gulf Crossing Pipeline began ramping up its operations and the Sherman Extension is currently flowing approximately 650 MMcf/d.

Gross operating margin from our natural gas storage business was $12.4 million for the second quarter of 2009 compared to $7.8 million for the second quarter of 2008. The $4.6 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. We placed in service an additional natural gas storage cavern having 4.2 Bcf of subscribed capacity at our Petal facility during the third quarter of 2008. Our Wilson facility benefited quarter-to-quarter from an increase in firm storage reservation volumes.

Offshore Pipelines & Services. Gross operating margin from this business segment was $33.1 million for the second quarter of 2009 compared to $35.3 million for the second quarter of 2008. Results from this business segment for the second quarter of 2009 were negatively impacted by our dissociation from TOPS and ongoing repairs to downstream infrastructure damaged by Hurricanes Gustav and Ike, which resulted in prolonged downtime and continued supply interruptions for certain of our offshore assets. Combined gross operating margin from our Independence Hub platform and Trail pipeline increased $44.0

million quarter-to-quarter. These assets were out of service for approximately 66 days due to repairs during the second quarter of 2008.

Gross operating margin from our offshore crude oil pipeline business was a loss of $19.9 million for the second quarter of 2009 compared to earnings of $14.8 million for the second quarter of 2008, a $34.7 million quarter-to-quarter decrease. Results for the second quarter of 2009 include a $34.2 million non-cash charge due to our dissociation from TOPS.

We completed the Shenzi crude oil pipeline and placed this asset into commercial operation during April 2009. Results for the second quarter of 2009 include $6.2 million of gross operating margin generated by the Shenzi crude oil pipeline and 68 MBPD of transportation volumes. Collectively, gross operating margin from the remainder of our crude oil pipelines decreased $6.7 million quarter-to-quarter due to the lingering effects of Hurricanes Gustav and Ike. Total offshore crude oil transportation volumes were 244 MBPD during the second quarter of 2009 versus 216 MBPD during the second quarter of 2008.

Gross operating margin from our offshore natural gas pipeline business was $16.8 million for the second quarter of 2009 compared to a loss of $11.1 million for the second quarter of 2008, a $27.9 million quarter-to-quarter increase. Offshore natural gas transportation volumes were 1,460 BBtus/d during the second quarter of 2009 versus 1,170 BBtus/d during the second quarter of 2008. Gross operating margin from our Independence Trail pipeline increased $30.3 million quarter-to-quarter. Results for the Independence Trail pipeline were negatively impacted during the second quarter of 2008 due to downtime and expenses as a result of flex-joint repairs. Collectively, gross operating margin from our other offshore natural gas pipelines decreased $2.4 million quarter-to-quarter due to lingering hurricane effects.

Gross operating margin from our offshore platform services business was $36.2 million for the second quarter of 2009 compared to $31.6 million for the second quarter of 2008, a $4.6 million quarter-to-quarter increase. Gross operating margin from our Independence Hub platform increased $13.7 million quarter-to-quarter. Collectively, gross operating margin from our other offshore platforms decreased $9.1 million quarter-to-quarter primarily due to the expiration of demand fee revenues at our Marco Polo platform in April 2009 and the effects of continued disruptions caused by Hurricanes Gustav and Ike. Our net platform natural gas processing volumes increased to 765 MMcf/d during the second quarter of 2009 from 353 MMcf/d during the second quarter of 2008. Our net platform crude oil processing volumes decreased to 10 MBPD during the second quarter of 2009 compared to 22 MBPD during the second quarter of 2008.

On August 4, 2009, the operator of the Independence Hub platform announced that it expects to perform scheduled maintenance on the platform beginning August 4, 2009 through the end of the third quarter of 2009. The planned maintenance will result in an estimated reduction in natural gas volumes of between 150 MMcf/d and 250 MMcf/d, gross, on any given day from previous run-rate levels. Also on August 4, 2009, we experienced a fire at our platform connected to our High Island Offshore System. The platform was evacuated and the fire was extinguished. We are still in the process of assessing the extent of the damage. Based on information currently available, management does not expect that these two developments will have a material impact on our consolidated financial position, results of operations or cash flows.

Petrochemical Services. Gross operating margin from this business segment was $47.8 million for the second quarter of 2009 compared to $58.2 million for the second quarter of 2008. Gross operating margin from our butane isomerization business was $19.1 million for the second quarter of 2009 compared to $30.9 million for the second quarter of 2008. The $11.8 million quarter-to-quarter decrease in gross operating margin from this business is attributable to lower proceeds from the sale of by-products as a result of lower commodity prices. Butane isomerization volumes increased to 100 MBPD during the second quarter of 2009 from 89 MBPD during the second quarter of 2008.

Gross operating margin from our propylene fractionation and pipeline business was $21.7 million for the second quarter of 2009 compared to $17.9 million for the second quarter of 2008. The $3.8 million quarter-to-quarter increase in gross operating margin is largely due to higher propylene sales volumes and lower fuel costs. Propylene fractionation volumes increased to 67 MBPD during the second quarter of 2009 from 61 MBPD during the second quarter of 2008. Gross operating margin from our octane enhancement business was $7.0 million for the second quarter of 2009 compared to $9.4 million for the second quarter of 2008. The $2.4 million quarter-to-quarter decrease in gross operating margin is due to higher maintenance expenses and lower isooctane production volumes.

Comparison of Six Months Ended June 30, 2009 with Six Months Ended June 30, 2008

Revenues for the first six months of 2009 were $6.93 billion compared to $12.02 billion for the first six months of 2008. The $5.09 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 six months of 2009 relative to the first six months of 2008.

Operating costs and expenses were $6.18 billion for the first six months of 2009 versus $11.27 billion for the first six months of 2008, a $5.09 billion period-to-period decrease. The cost of sales of our marketing activities decreased $4.32 billion period-to-period primarily due to lower energy commodity prices. Likewise, the operating costs and expenses of our natural gas processing plants decreased $664.6 million period-to-period primarily due to lower PTR costs attributable to the decline in energy commodity prices. General and administrative costs increased $5.6 million period-to-period primarily due to expenses we incurred during the first six months of 2009 in connection with the proposed merger of Enterprise Products Partners with TEPPCO and TEPPCO GP.

Changes in our revenues and costs and expenses period-to-period are primarily explained by changes in energy commodity prices. The weighted-average indicative market price for NGLs was $0.71 per gallon during the first six months of 2009 versus $1.60 per gallon during the first six months of 2008 – a 56% decrease period-to-period. The Henry Hub market price of natural gas decreased 56% period-to-period to an average of $4.21 per MMBtu during the first six months of 2009 versus $9.49 per MMBtu during the first six months of 2008.

Equity in income (loss) from our unconsolidated affiliates was a loss of $4.2 million for the first six months of 2009 compared to earnings of $33.2 million for the first six months of 2008, a $37.4 million period-to-period decrease. Equity in loss of unconsolidated affiliates for the first six months of 2009 include a $34.2 million non-cash charge related to our dissociation from TOPS. Our investments in White River Hub and Skelly-Belvieu contributed equity in income of $2.0 million and $1.1 million, respectively, for the first six months of 2009. Collectively, equity in loss of unconsolidated affiliates from our other equity investments decreased $6.3 million period-to-period primarily due to the expiration of demand fee revenues on our Marco Polo platform during the second quarter of 2009 and reduced volumes on the Cameron Highway crude oil pipeline due to the lingering effects of Hurricanes Gustav and Ike.

Operating income for the first six months of 2009 was $700.5 million compared to $741.0 million for the first six 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 loss of unconsolidated affiliates contributed to the $40.5 million period-to-period decrease in operating income.

Interest expense increased to $246.6 million for the first six months of 2009 from $187.7 million for the first six months of 2008. The $58.9 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 $18.0 million decrease in capitalized interest during the first six months of 2009 relative to the first six months of 2008. Average debt principal increased during the first six months of 2009 to $9.28 billion from $7.38 billion during the first six 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 sale of certain assets during the first six months of 2009.

As a result of items noted in the previous paragraphs, net income decreased $106.9 million period-to-period to $437.4 million for the first six months of 2009 compared to $544.3 million for the first six months of 2008. Net income attributable to noncontrolling interests was $25.5 million for 2009 compared to $21.4 million for 2008. Net income attributable to Enterprise Products Partners decreased $111.0

million period-to-period to $411.9 million for the first six months of 2009 compared to $522.9 million for the first six months of 2008.

We estimate that gross operating margin was reduced by approximately $33.0 million during the first six months of 2009 due to the lingering effects of Hurricanes Gustav and Ike. 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 $696.8 million for the first six months of 2009 compared to $607.4 million for the first six months of 2008, an $89.4 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 six months of 2009 compared to the first six months of 2008.

Gross operating margin from our natural gas processing and related NGL marketing business was $413.9 million for the first six months of 2009 compared to $375.0 million for the first six months of 2008. Equity NGL production increased to 116 MBPD during the first six months of 2009 from 107 MBPD during the first six months of 2008. The $38.9 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 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 $217.7 million for the first six months of 2009 compared to $180.4 million for the first six months of 2008, a $37.3 million period-to-period increase. Total NGL transportation volumes increased to 1,866 MBPD during the first six months of 2009 from 1,803 MBPD during the first six months of 2008. Gross operating margin from our Mont Belvieu Storage complex increased $11.3 million period-to-period primarily due to increased volumes and fees. Collectively, gross operating margin from the remainder of our NGL pipelines and related storage assets increased $26.0 million. This was largely due to lower fuel costs, higher NGL export volumes and higher volumes and fees at certain of our assets in south Louisiana during the first six months of 2009 relative to the first six months of 2008.

Gross operating margin from our NGL fractionation business was $65.2 million for the first six months of 2009 compared to $52.0 million for the first six months of 2008. Fractionation volumes increased to 440 MBPD during the first six months of 2009 from 430 MBPD during the first six months of 2008. Gross operating margin from this business increased $13.2 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 six months of 2009 relative to the first six months of 2008.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $190.3 million for the first six months of 2009 compared to $233.1 million for the first six months of 2008, a $42.8 million period-to-period decrease. Our onshore natural gas transportation volumes were 8,120 BBtus/d during the first six months of 2009 compared to 7,188 BBtus/d during the first six months of 2008.

Gross operating margin from our onshore natural gas pipeline and related natural gas marketing business decreased $50.0 million period-to-period to $164.8 million for the first six months of 2009 from $214.8 million for the first six months of 2008. Gross operating margin from this business decreased $79.6 million primarily due to lower revenues earned by our San Juan gathering system from fees indexed to regional natural gas prices, lower condensate sales revenues as a result of a period-to-period decrease in commodity prices and lower natural gas sales volumes and margins on our Acadian Gas System. Collectively, gross operating margin from the remainder of this business increased $29.6 million period-to-period attributable to increased natural gas sales volumes and improved asset utilization as a result of our natural gas marketing activities.

Gross operating margin from our natural gas storage business was $25.5 million for the first six months of 2009 compared to $18.3 million for the first six months of 2008. The $7.2 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 $94.4 million for the first six months of 2009 compared to $116.9 million for the first six months of 2008. Results from this business segment for the first six months of 2009 were negatively impacted by our dissociation from TOPS and ongoing repairs to downstream infrastructure damaged by Hurricanes Gustav and Ike, which resulted in prolonged downtime and continued supply interruptions for certain of our offshore assets. Combined gross operating margin from our Independence Hub platform and Trail pipeline increased $45.8 million period-to-period reflecting downtime and repair expense incurred during the first six months of 2008.

Gross operating margin from our offshore crude oil pipeline business was a loss of $14.8 million for the first six months of 2009 compared to earnings of $27.0 million for the first six months of 2008, a $41.8 million period-to-period decrease. Total offshore crude oil transportation volumes were 219 MBPD during the first six months of 2009 versus 211 MBPD during the first six months of 2008. Results for the first six months of 2009 include a $34.2 million non-cash charge resulting from our dissociation from TOPS. In addition, gross operating margin decreased $13.8 million period-to-period primarily due to the lingering effects of Hurricanes Gustav and Ike. The recently completed Shenzi crude oil pipeline contributed $6.2 million of gross operating margin and 68 MBPD of transportation volumes during the first six months of 2009.

Gross operating margin from our offshore natural gas pipeline business was $34.5 million for the first six months of 2009 compared to $14.7 million for the first six months of 2008, a $19.8 million period-to-period increase. Offshore natural gas transportation volumes were 1,501 BBtus/d during the first six months of 2009 versus 1,553 BBtus/d during the first six months of 2008. Gross operating margin from our Independence Trail pipeline increased $31.1 million period-to-period. Collectively, gross operating margin from our other offshore natural gas pipelines decreased $11.3 million period-to-period primarily due to lingering hurricane effects.

Gross operating margin from our offshore platform services business was $74.7 million for the first six months of 2009 compared to $75.2 million for the first six months of 2008, a $0.5 million period-to-period decrease. Gross operating margin from our Independence Hub platform increased $14.6 million period-to-period. Collectively, gross operating margin from our other offshore platforms and related assets decreased $15.1 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 771 MMcf/d during the first six months of 2009 compared to 591 MMcf/d during the first six months of 2008. Our net platform crude oil processing volumes decreased to 7 MBPD during the first six months of 2009 compared to 21 MBPD during the first six months of 2008.

Petrochemical Services. Gross operating margin from this business segment was $76.4 million for the first six months of 2009 compared to $99.2 million for the first six months of 2008. Gross operating margin from our butane isomerization business was $34.0 million for the first six months of 2009 compared to $58.8 million for the first six months of 2008. The $24.8 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 95 MBPD during the first six months of 2009 from 92 MBPD during the first six months of 2008.

Gross operating margin from our propylene fractionation and pipeline business was $43.5 million for the first six months of 2009 compared to $33.2 million for the first six months of 2008. The $10.3 million period-to-period increase in gross operating margin is largely due to higher propylene sales margins and volumes during the first six months of 2009 relative to the first six months of 2008. Propylene fractionation volumes increased to 67 MBPD during the first six months of 2009 from 60 MBPD during the first six months of 2008. Gross operating margin from our octane enhancement business was a loss of $1.1 million for the first six months of 2009 compared to earnings of $7.2 million for the first six months of 2008. The $8.3 million period-to-period decrease in gross operating margin is due to prolonged downtime and higher repair expenses associated with scheduled maintenance activities during 2009.

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 June 30, 2009, we had $65.0 million of unrestricted cash on hand and approximately $872.6 million of available credit under EPO's Multi-Year Revolving Credit Facility. We had approximately $9.36 billion in principal outstanding under consolidated debt agreements at June 30, 2009. In total, our consolidated liquidity at June 30, 2009 was approximately $1.08 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 sold 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. We used the net proceeds of $225.6 million from the 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 universal shelf 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.

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 six months ended June 30, 2009, we issued 7,247,980 common units in connection with our DRIP, which generated proceeds of $162.5 million from plan participants. Affiliates of EPCO reinvested $144.0 million in connection with the DRIP during the six months ended June 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 six months ended June 30, 2009, we issued 102,862 common units to employees under this plan, which generated proceeds of $2.5 million.

Duncan Energy Partners has a universal shelf registration statement filed with the SEC that authorizes its issuance of up to $1.0 billion in debt and equity securities. Duncan Energy Partners issued an aggregate 8.9 million of its common units in June and July 2009, which generated net proceeds of approximately $137.7 million ($123.2 million had been received as of June 30, 2009). 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. After taking into account such issuance of securities under this universal shelf registration statement, Duncan Energy Partners can issue approximately $856.4 million of additional securities under this registration statement as of August 1, 2009.

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 June 30, 2009, EPO had outstanding a $60.0 million letter of credit relating to its commodity derivative instruments and a $50.7 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 June 30, 2009, which does reduce 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 assigned a rating of Baa3 and Standard & Poor's and Fitch Ratings 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.

On June 29, 2009, following the announcement that we and TEPPCO had executed definitive agreements to merge, Fitch affirmed its rating for our and TEPPCO's senior notes, while Moody's and Standard & Poor's published reports indicating that the proposed merger did not affect our and TEPPCO's ratings. Moody's added that the combination "would further strengthen Enterprise's position within its Baa3 rating." Each agency assumed, based on management's objectives, that (i) the debt of TEPPCO and EPO would be pari passu upon completion of the merger, (ii) we will be able to maintain or refinance TEPPCO's current revolver borrowings, and (iii) the pro forma credit measures of EPO remain consistent with pre-merger estimates. We do not expect a change in our credit ratings if the proposed merger is consummated in accordance with the terms of the definitive merger agreements.

TEPPCO's senior notes are also rated investment grade. TEPPCO's senior notes are rated BBB-, BBB-, and Baa3 by Fitch, Standard & Poor's and Moody's, respectively.

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 Six Months Ended June 30,	
	2009	**2008**
Net cash flows provided by operating activities	$ 437.7	$ 696.7
Cash used in investing activities	642.2	1,032.0
Cash provided by financing activities	236.3	320.2

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

Comparison of Six Months Ended June 30, 2009 with Six Months Ended June 30, 2008

Operating Activities. Net cash flows provided by operating activities were $437.7 million for the six months ended June 30, 2009 compared to $696.7 million for the six months ended June 30, 2008. This $259.0 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 $229.6 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 NGL 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. Of the $527.0 million in forward sales inventory at June 30, 2009, approximately $432.0 million relates to forward sales NGL volumes. In general, the significant increase in volumes dedicated to forward physical sales contracts improves the overall utilization and profitability of our fee-based assets. The cash invested in forward sales NGL inventories is expected to be recovered within the next twelve months, with approximately $163.4 million realized by December 31, 2009.

§ Cash payments for interest increased $11.9 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 $17.5 million for the six months ended June 30, 2009 compared to the six months ended June 30, 2008 primarily due to lower distributions received from Deepwater Gateway, L.L.C.

Investing Activities. Cash used in investing activities was $642.2 million for the six months ended June 30, 2009 compared to $1.03 billion for the six months ended June 30, 2008. This $389.8 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 $443.7 million period-to-period. For additional information related to our capital spending program, see "Capital Spending" included within this Item 2.

§ Cash inflows from decreases in restricted cash related to our hedging activities were reduced $51.6 million period-to-period primarily due to the reduction of margin requirements related to derivative instruments held.

§ Cash used for business combinations for the six months ended June 30, 2009 reflects our $23.7 million acquisition of rail and truck terminal facilities located in Mont Belvieu, Texas from Martin Midstream Partners L.P. ("Martin") in May 2009.

Financing Activities. Cash provided by financing activities was $236.3 million for the six months ended June 30, 2009 compared to $320.2 million for the six months ended June 30, 2008. This $83.9 million decrease in cash provided by financing activities was primarily due to the following:

§ Net borrowings under our consolidated debt agreements were $313.9 million during the six months ended June 30, 2009 compared to $851.7 million during the six months ended June 30, 2008. The $537.8 million decrease in net borrowings was attributable to lower amounts of senior notes issued period-to-period and the repayment of the $217.6 million Yen Term Loan in March 2009, partially offset by an increase in net repayments under EPO's Multi-Year Revolving Credit Facility period-to-period. During the six months ended June 30, 2008, EPO issued $1.10 billion in senior notes (Senior Notes M and N), compared to $500.0 million in senior notes (Senior Notes P) during the six months ended June 30, 2009.

§ Cash distributions to our partners increased $57.4 million period-to-period primarily due to increases to our common units outstanding and quarterly distribution rates.

§ Net proceeds from issuance of common units increased $360.8 million period-to-period primarily due to the January 2009 issuance of underwritten common units that generated net proceeds of $225.6 million and an increase of $131.0 million in proceeds generated by our DRIP and EUPP period-to-period. Affiliates of EPCO reinvested $144.0 million of their distributions through the DRIP during the six months ended June 30, 2009.

§ Contributions from noncontrolling interests were $123.2 million for the six months ended June 30, 2009, which represents the net proceeds that Duncan Energy Partners received from its equity offering of 8,000,000 common units in June 2009. Duncan Energy Partners used the net proceeds from this offering to repurchase and cancel an equal number of 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 Six Months Ended June 30,	
	2009	**2008**
Capital spending for property, plant and equipment, net of contributions in aid of construction costs	$ 629.7	$ 1,073.4
Capital spending for business combinations	23.7	--
Capital spending for intangible assets	--	5.1
Capital spending for investments in unconsolidated affiliates	12.5	25.0
Total capital spending	$ 665.9	$ 1,103.5

Based on information currently available, we estimate our consolidated capital spending for the remainder of 2009 (i.e., the third and fourth quarters) will approximate $475.0 million, which includes estimated expenditures of $365.0 million for growth capital projects and acquisitions and $110.0 million for sustaining capital expenditures.

Our forecast of consolidated capital expenditures is based on our current announced strategic operating and growth plans and exclude amounts associated with TOPS, which we announced our dissociation from in April 2009. 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 June 30, 2009, we had approximately $259.3 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.

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 June 30,		For the Six Months Ended June 30,	
	2009	**2008**	**2009**	**2008**
Expensed	$ 12.5	$ 12.1	$ 18.2	$ 23.8
Capitalized	8.9	17.3	11.8	22.8
Total	$ 21.4	$ 29.4	$ 30.0	$ 46.6

We expect the costs of our pipeline integrity program, irrespective of whether such costs are capitalized or expensed, to approximate $64.4 million for the remainder of 2009.

Other Items

Contractual Obligations

With the exception of the issuance of Senior Notes P, routine fluctuations in the balance of our consolidated revolving credit facilities, execution of a long-term right-of-way agreement with the Jicarilla Apache Nation, termination of a lease agreement with Martin for rail and truck terminal facilities in Mont Belvieu, Texas and the effects of our dissociation from TOPS on our purchase commitments, there have been no significant changes in our contractual obligations since those reported in our Recast Form 8-K.

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

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

	For the Three Months Ended June 30, 2009	For the Three Months Ended June 30, 2008	For the Six Months Ended June 30, 2009	For the Six Months Ended June 30, 2008
Revenues from consolidated operations:				
EPCO and affiliates	$ 32.7	$ 26.3	$ 57.8	$ 44.7
Energy Transfer Equity and subsidiaries	49.2	90.3	212.0	313.4
Unconsolidated affiliates	43.2	106.2	99.8	165.4
Total	$ 125.1	$ 222.8	$ 369.6	$ 523.5
Cost of sales:				
EPCO and affiliates	$ 15.2	$ 9.8	$ 43.6	$ 25.6
Energy Transfer Equity and subsidiaries	95.9	23.3	185.9	68.8
Unconsolidated affiliates	11.4	23.9	24.5	52.2
Total	$ 122.5	$ 57.0	$ 254.0	$ 146.6
Operating costs and expenses:				
EPCO and affiliates	$ 87.0	$ 75.0	$ 166.5	$ 160.9
Energy Transfer Equity and subsidiaries	1.9	5.8	3.3	9.1
Unconsolidated affiliates	(2.5)	(2.5)	(5.2)	(4.7)
Total	$ 86.4	$ 78.3	$ 164.6	$ 165.3
General and administrative expenses:				
EPCO and affiliates	$ 16.6	$ 13.5	$ 34.4	$ 31.2
Other expense:				
EPCO and affiliates	$ --	$ --	$ --	$ 0.3

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

	June 30, 2009	December 31, 2008
Accounts receivable - related parties:		
EPCO and affiliates	$ 36.9	$ 26.6
Energy Transfer Equity and subsidiaries	5.4	35.0
Unconsolidated affiliates	5.1	--
Total	$ 47.4	$ 61.6
Accounts payable - related parties:		
EPCO and affiliates	$ 63.3	$ 39.4
Energy Transfer Equity and subsidiaries	28.9	0.2
Unconsolidated affiliates	3.8	--
Total	$ 96.0	$ 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 June 30,		For the Six Months Ended June 30,	
	2009	2008	2009	2008
Total segment gross operating margin	$ 509.2	$ 534.4	$ 1,057.9	$ 1,056.6
Adjustments to reconcile total segment gross operating margin to operating income:				
Depreciation, amortization and accretion in operating costs and expenses	(153.2)	(136.3)	(306.7)	(270.2)
Operating lease expense paid by EPCO	(0.1)	(0.5)	(0.3)	(1.0)
Gain from asset sales and related transactions in operating costs and expenses	0.2	0.7	0.4	0.8
General and administrative costs	(27.8)	(24.0)	(50.8)	(45.2)
Operating income	328.3	374.3	700.5	741.0
Other expense, net	(126.0)	(95.1)	(245.7)	(186.1)
Income before provision for income taxes	$ 202.3	$ 279.2	$ 454.8	$ 554.9

Recent Accounting Pronouncements

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

- § FSP FAS 157-4 (ASC 820), *Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly*;
- § FSP FAS 107-1 and APB 28-1 (ASC 825), *Interim Disclosures About Fair Value of Financial Instruments*;
- § SFAS 165 (ASC 855), *Subsequent Events*;
- § SFAS 167 (ASC 810), *Amendments to FASB Interpretation No. 46(R)*; and
- § SFAS 168 (ASC 105), *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles – a replacement of FASB Statement No. 162*.

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 remained unchanged 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 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**	**June 30, 2009**	**July 21, 2009**
FV assuming no change in underlying interest rates	*Asset*	$ 32.8	$ 39.0
FV assuming 10% increase in underlying interest rates	*Asset*	25.6	32.4
FV assuming 10% decrease in underlying interest rates	*Asset*	40.1	45.7

Duncan Energy Partners	**Resulting**	**Swap Fair Value at**	
Scenario	**Classification**	**June 30, 2009**	**July 21, 2009**
FV assuming no change in underlying interest rates	*Liability*	$ 6.7	$ 7.0
FV assuming 10% increase in underlying interest rates	*Liability*	6.4	6.7
FV assuming 10% decrease in underlying interest rates	*Liability*	7.0	7.3

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 June 30, 2009	Portfolio Fair Value at July 21, 2009
FV assuming no change in underlying commodity prices	*Asset*	$ 15.7	$ 10.5
FV assuming 10% increase in underlying commodity prices	*Asset*	14.1	7.4
FV assuming 10% decrease in underlying commodity prices	*Asset*	17.3	13.6

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 June 30, 2009	Portfolio Fair Value at July 21, 2009
FV assuming no change in underlying commodity prices	*Liability*	$ 140.4	$ 115.2
FV assuming 10% increase in underlying commodity prices	*Liability*	165.8	124.0
FV assuming 10% decrease in underlying commodity prices	*Liability*	115.0	106.3

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 (see Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report). 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.

We had one foreign currency derivative instrument with a notional amount of $1.7 million Canadian outstanding at June 30, 2009. The fair market value of this instrument was an asset of $0.1 million at June 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 second 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 factor set forth below and 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.

Our prior interest in the TOPS partnership and dissociation from the partnership in April 2009 could subject us to various liabilities.

TOPS was expected to represent an important component of our Offshore Pipelines & Services segment, requiring an estimated $600.0 million in capital contributions from us through 2011. Effective April 16, 2009, we and a subsidiary of TEPPCO elected to dissociate, or exit, from TOPS. In dissociating from TOPS, we forfeited our investment and one-third ownership interest in the partnership. As a result, our equity earnings and net income for the second quarter of 2009 includes a non-cash charge of $34.2 million.

The third partner, an affiliate of Oiltanking, has 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. We have not recorded any reserves for potential liabilities relating to this matter, although we may determine in future periods that an accrual of reserves for potential liabilities (including costs of litigation) should be made.

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

As of June 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 six months ended June 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	--	--

(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.

Item 3. ***Defaults upon Senior Securities.***

None.

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

None.

Item 5. ***Other Information.***

Loan Agreement with TEPPCO

On August 5, 2009, EPO entered into a 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. Borrowings under the Loan Agreement mature on the earliest to occur of (i) the consummation of our proposed merger with TEPPCO, (ii) the termination of the related merger agreement in accordance with the provisions thereof, (iii) December 31, 2009, (iv) the date upon which the maturity of the loan is otherwise accelerated upon an event of default, and (v) the date upon which EPO's commitment to make the loan is terminated by TEPPCO pursuant to the Loan Agreement. Borrowings under the Loan Agreement will bear interest at a floating rate equivalent to the one-month LIBOR Rate (as defined in the Loan Agreement) plus 2%. Interest is payable monthly.

The Loan Agreement provides that amounts borrowed are non-recourse to TEPPCO GP and TEPPCO's limited partners. The Loan Agreement contains customary events of default, including (i) nonpayment of principal when due or nonpayment of interest or other amounts within three business days of when due, (ii) bankruptcy or insolvency with respect to TEPPCO, (iii) a change of control, or (iv) an event of default under TEPPCO's revolving credit facility. Any amounts due by TEPPCO under the Loan Agreement will be unconditionally and irrevocably guaranteed by each TEPPCO subsidiary that guarantees TEPPCO's obligations under its revolving credit facility. EPO's obligation to fund any borrowings under the Loan Agreement is subject to specified conditions, including the condition that, on and as of the applicable date of funding, no additional amounts are available to TEPPCO pursuant to TEPPCO's revolving credit facility (either as borrowings or under any letters of credit).

The foregoing description of the Loan Agreement is qualified in its entirety by reference to the full and complete terms of the Loan Agreement, which is incorporated by reference into this Quarterly Report as Exhibit 10.10.

The execution of the Loan Agreement was unanimously approved by the ACG Committees of EPGP and TEPPCO GP.

Settlement Agreement

On August 5, 2009, the parties to the Merger Action and the Derivative Action described in Note 14 of the Notes to Unaudited Condensed Consolidated Financial Statements included in Item 1 of this Quarterly Report entered into the Settlement Agreement. Pursuant to the Settlement Agreement, the board of directors of TEPPCO GP will recommend to TEPPCO's unitholders that they approve the adoption of the merger agreement governing TEPPCO's proposed merger with a subsidiary of ours and take all necessary steps to seek unitholder approval for the merger as soon as practicable. Pursuant to the Settlement Agreement, approval of the merger will require, 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'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. 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. See Note 12 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report for additional information regarding our relationship with TEPPCO, including information related to the proposed merger. See Note 14 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this Quarterly Report for additional information related to the Merger Action and the Derivative Action, including the Settlement Agreement.

The foregoing description of the Settlement Agreement is qualified in its entirety by reference to the full and complete terms of the Settlement Agreement, which is incorporated by reference into this Quarterly Report as Exhibit 10.9.

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	First Amendment to the Fifth Amended and Restated Partnership Agreement 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	Second Amendment to the Fifth Amended and Restated Partnership Agreement 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	Third Amendment to the Fifth Amended and Restated Partnership Agreement 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	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).
3.7	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).
3.8	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).
3.9	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).
3.10	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).
3.11	Certificate of Limited Partnership of Duncan Energy Partners L.P. (incorporated by reference to Exhibit 3.1 to Duncan Energy Partners L.P.'s Form S-1 Registration Statement, Reg. No. 333-138371, filed November 2, 2006).
3.12	Amended and Restated Agreement of Limited Partnership of Duncan Energy Partners L.P., dated February 5, 2007 (incorporated by reference to Exhibit 3.1 to Duncan Energy Partners L.P.'s Form 8-K filed February 5, 2007).
3.13	First Amendment to Amended and Restated Partnership Agreement of Duncan Energy Partners L.P. dated as of December 27, 2007 (incorporated by reference to Exhibit 3.1 to Duncan Energy Partners L.P.'s Form 8-K/A filed on January 3, 2008).
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 LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, 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 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 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 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 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 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 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 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 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 to Indenture dated 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 July 19, 2006).

4.17	Ninth Supplemental Indenture, dated as of May 24, 2007, by and 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, by and 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, by and 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 on September 5, 2007).
4.20	Twelfth Supplemental Indenture, dated as of April 3, 2008, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as 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 L.P., as Issuer, Enterprise Products Partners L.P., as 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 L.P., as Issuer, Enterprise Products Partners L.P., as 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 L.P., as Issuer, Enterprise Products Partners L.P., as 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	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 4.4 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.25	Global Note representing $500.0 million principal amount of 6.875% Series B Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.8 to Form 10-K filed March 31, 2003).
4.26	Global Notes 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).
4.27	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).
4.28	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).
4.29	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).
4.30	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).
4.31	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).
4.32	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).
4.33	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).

4.34	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).
4.35	Form of Junior Subordinated Note, including Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed July 19, 2006).
4.36	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).
4.37	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).
4.38	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).
4.39	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).
4.40	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).
4.41	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 the Current Report on Form 8-K filed by Enterprise Products Partners L.P. on May 24, 2007).
4.42	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).
4.43	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).
10.1	Amended and Restated Credit Agreement dated as of June 29, 2005, among Cameron Highway Oil Pipeline Company, the Lenders party thereto, and SunTrust Bank, as Administrative Agent and Collateral Agent (incorporated by reference to Exhibit 4.1 to Form 8-K filed on July 1, 2005).
10.2	Amended and Restated Omnibus Agreement dated as of December 8, 2008 among Enterprise Products Operating LLC, DEP Holdings, LLC, Duncan Energy Partners L.P., DEP OLPGP, LLC, DEP Operating Partnership, L.P., Enterprise Lou-Tex Propylene Pipeline L.P., Sabine Propylene Pipeline L.P., Acadian Gas, LLC, Mont Belvieu Caverns, LLC, South Texas NGL Pipelines, LLC, Enterprise Holding III, L.L.C., Enterprise Texas Pipeline, LLC, Enterprise Intrastate, L.P. and Enterprise GC, LP (incorporated by reference to Exhibit 10.6 of Form 8-K filed by Duncan Energy Partners L.P. on December 8, 2008).
10.3	Contribution, Conveyance and Assumption Agreement dated as of December 8, 2008 by and among Duncan Energy Partners L.P., DEP OLPGP, LLC, DEP Operating Partnership, L.P., Enterprise GTM Holdings L.P. and Enterprise Holding III, L.L.C. (incorporated by reference to Exhibit 10.2 of Form 8-K filed by Duncan Energy Partners L.P. on December 8, 2008).

10.4	Fifth Amended and Restated Administrative Services Agreement by and among EPCO, Inc., Enterprise Products Partners L.P., Enterprise Products Operating L.P., Enterprise Products GP, LLC, Enterprise Products OLPGP, Inc., Enterprise GP Holdings L.P., EPE Holdings, LLC, DEP Holdings, LLC, Duncan Energy Partners L.P., DEP OLPGP, LLC, DEP Operating Partnership L.P., TEPPCO Partners, L.P., Texas Eastern Products Pipeline Company, LLC, TE Products Pipeline Company, Limited Partnership, TEPPCO Midstream Companies, L.P., TCTM, L.P. and TEPPCO GP, Inc. dated January 30, 2009 (incorporated by reference to Exhibit 10.1 to the Form 8-K filed by Enterprise Products Partners L.P. on February 5, 2009).
10.5	Term Loan Credit Agreement dated as of April 1, 2009 among Enterprise Products Operating LLC, the financial institutions party thereto as lenders, Mizuho Corporate Bank, Ltd., as administrative agent, a lender and as sole lead arranger (incorporated by reference to Exhibit 10.1 to Form 8-K on April 2, 2009).
10.6	Guaranty Agreement dated as of April 1, 2009 executed by Enterprise Products Partners L.P. in favor of Mizuho Corporate Bank, Ltd., as administrative agent (incorporated by reference to Exhibit 10.2 to Form 8-K on April 2, 2009).
10.7	Support Agreement, dated as of June 28, 2009, by and among Enterprise Products Partners L.P., Enterprise GP Holdings L.P., DD Securities LLC, DFI GP Holdings, L.P., Duncan Family Interests Inc., Duncan Family 2000 Trust and Dan Duncan (incorporated by reference to Exhibit 10.1 to Form 8-K on June 29, 2009).
10.8	Memorandum of Understanding, dated June 28, 2009 (incorporated by reference to Exhibit 10.2 to Form 8-K on June 29, 2009).
10.9	Stipulation and Agreement of Compromise, Settlement and Release, dated August 5, 2009 (incorporated by reference to Exhibit 10.3 to the Form 10-Q filed by TEPPCO Partners, L.P. on August 6, 2009).
10.10	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 the Form 10-Q filed by TEPPCO Partners, L.P. on August 6, 2009).
31.1#	Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise Products Partners L.P. for the June 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 June 30, 2009 quarterly report on Form 10-Q.
32.1#	Section 1350 certification of Michael A. Creel for the June 30, 2009 quarterly report on Form 10-Q.
32.2#	Section 1350 certification of W. Randall Fowler for the June 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 August 6, 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: August 6, 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: August 6, 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 June 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: August 6, 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 June 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: August 6, 2009