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, 2010

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from ___ to ___.

Commission file number: 1-14323

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 Street, 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 ☐

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 ☐
Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

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

Yes ☐ No ☑

There were 636,721,700 common units, including 3,638,381 restricted common units, and 4,520,431 Class B units (which generally vote together with the common units) of Enterprise Products Partners L.P. outstanding at August 1, 2010. Our 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, 2010	December 31, 2009
Current assets:		
Cash and cash equivalents	$ 494.5	$ 54.7
Restricted cash	19.1	63.6
Accounts and notes receivable – trade, net of allowance for doubtful accounts of $17.5 at June 30, 2010 and $16.8 at December 31, 2009	2,913.5	3,099.0
Accounts receivable – related parties	29.8	38.4
Inventories	1,025.5	711.9
Prepaid and other current assets	423.2	279.3
Total current assets	4,905.6	4,246.9
Property, plant and equipment, net	18,332.0	17,689.2
Investments in unconsolidated affiliates	873.2	890.6
Intangible assets, net of accumulated amortization of $858.7 at June 30, 2010 and $795.0 at December 31, 2009	1,896.1	1,064.8
Goodwill	2,050.6	2,018.3
Other assets	232.0	241.8
Total assets	$ 28,289.5	$ 26,151.6
LIABILITIES AND EQUITY		
Current liabilities:		
Current maturities of long-term debt	$ 255.0	$ --
Accounts payable – trade	457.9	410.6
Accounts payable – related parties	136.9	69.8
Accrued product payables	3,120.9	3,393.0
Accrued interest	232.9	228.0
Other current liabilities	463.8	434.6
Total current liabilities	4,667.4	4,536.0
Long-term debt (see Note 10)	12,416.5	11,346.4
Deferred tax liabilities	72.9	71.7
Other long-term liabilities	207.3	155.2
Commitments and contingencies		
Equity: (see Note 11)		
Enterprise Products Partners L.P. partners' equity:		
Limited Partners:		
Common units (633,084,119 units outstanding at June 30, 2010 and 603,202,828 units outstanding at December 31, 2009)	10,053.0	9,173.5
Restricted common units (3,638,381 units outstanding at June 30, 2010 and 2,720,882 units outstanding at December 31, 2009)	49.3	37.7
Class B units (4,520,431 units outstanding at June 30, 2010 and December 31, 2009)	118.5	118.5
General partner	208.8	190.8
Accumulated other comprehensive loss	(33.2)	(8.4)
Total Enterprise Products Partners L.P. partners' equity	10,396.4	9,512.1
Noncontrolling interest	529.0	530.2
Total equity	10,925.4	10,042.3
Total liabilities and equity	$ 28,289.5	$ 26,151.6

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,	
	2010	2009*	2010	2009*
Revenues:				
Third parties	$ 7,427.4	$ 5,342.0	$ 15,739.5	$ 10,009.4
Related parties	116.0	92.3	348.4	311.8
Total revenues (see Note 12)	7,543.4	5,434.3	16,087.9	10,321.2
Costs and expenses:				
Operating costs and expenses:				
Third parties	6,676.1	4,771.1	14,324.0	8,918.2
Related parties	298.1	253.4	622.1	482.9
Total operating costs and expenses	6,974.2	5,024.5	14,946.1	9,401.1
General and administrative costs:				
Third parties	14.6	21.5	28.7	29.4
Related parties	23.3	24.6	46.8	51.6
Total general and administrative costs	37.9	46.1	75.5	81.0
Total costs and expenses (see Note 12)	7,012.1	5,070.6	15,021.6	9,482.1
Equity in income of unconsolidated affiliates	16.7	9.6	32.7	17.0
Operating income	548.0	373.3	1,099.0	856.1
Other income (expense):				
Interest expense	(168.6)	(158.5)	(317.2)	(311.0)
Interest income	0.5	0.7	0.7	1.6
Other, net	(0.1)	0.1	(0.2)	0.4
Total other expense, net	(168.2)	(157.7)	(316.7)	(309.0)
Income before provision for income taxes	379.8	215.6	782.3	547.1
Provision for income taxes	(6.5)	(3.1)	(15.2)	(19.1)
Net income	373.3	212.5	767.1	528.0
Net income attributable to noncontrolling interests	(16.1)	(25.9)	(32.1)	(116.1)
Net income attributable to Enterprise Products Partners L.P.	$ 357.2	$ 186.6	$ 735.0	$ 411.9
Allocation of net income attributable to Enterprise Products Partners L.P.:				
Limited partners	$ 294.3	$ 147.0	$ 611.7	$ 333.3
General partner	$ 62.9	$ 39.6	$ 123.3	$ 78.6
Basic earnings per unit (see Note 14)	$ 0.46	$ 0.32	$ 0.97	$ 0.73
Diluted earnings per unit (see Note 14)	$ 0.46	$ 0.32	$ 0.96	$ 0.73

See Notes to Unaudited Condensed Consolidated Financial Statements.

*See Note 1 for information regarding these recast amounts and basis of financial statement presentation.

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,	
	2010	2009*	2010	2009*
Net income	$ 373.3	$ 212.5	$ 767.1	$ 528.0
Other comprehensive income (loss):				
Cash flow hedges:				
Commodity derivative instrument gains (losses) during period	92.0	(76.6)	33.1	(138.6)
Reclassification adjustment for (gains) losses included in net income related to commodity derivative instruments	(1.5)	66.3	15.0	98.5
Interest rate derivative instrument gains (losses) during period	(70.8)	15.8	(76.5)	15.1
Reclassification adjustment for losses included in net income related to interest rate derivative instruments	3.3	2.5	6.6	4.8
Foreign currency derivative gains (losses) during period	(0.1)	0.1	(0.2)	(10.5)
Reclassification adjustment for gains included in net income related to foreign currency derivative instruments	--	--	(0.3)	--
Total cash flow hedges	22.9	8.1	(22.3)	(30.7)
Foreign currency translation adjustment	(0.8)	1.0	(0.2)	0.6
Change in funded status of pension and postretirement plans, net of tax	--	--	(0.9)	--
Total other comprehensive income (loss)	22.1	9.1	(23.4)	(30.1)
Comprehensive income	395.4	221.6	743.7	497.9
Comprehensive income attributable to noncontrolling interests	(16.8)	(27.5)	(33.5)	(119.7)
Comprehensive income attributable to Enterprise Products Partners L.P.	$ 378.6	$ 194.1	$ 710.2	$ 378.2

See Notes to Unaudited Condensed Consolidated Financial Statements.

*See Note 1 for information regarding these recast amounts and basis of financial statement presentation.

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

	For the Six Months Ended June 30, 2010	For the Six Months Ended June 30, 2009*
Operating activities:		
Net income	$ 767.1	$ 528.0
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	451.4	407.7
Non-cash asset impairment charges	1.5	2.3
Equity in income of unconsolidated affiliates	(32.7)	(17.0)
Distributions received from unconsolidated affiliates	58.8	33.5
Operating lease expenses paid by EPCO	0.3	0.3
Gains from asset sales and related transactions	(5.7)	(0.4)
Loss on forfeiture of investment in Texas Offshore Port System	--	68.4
Deferred income tax expense	1.3	1.8
Changes in fair market value of derivative instruments	(5.0)	(12.0)
Effect of pension settlement recognition	(0.2)	(0.1)
Net effect of changes in operating accounts (see Note 17)	(336.5)	(377.5)
Net cash flows provided by operating activities	900.3	635.0
Investing activities:		
Capital expenditures	(746.8)	(834.2)
Contributions in aid of construction costs	8.7	10.3
Decrease in restricted cash	52.6	19.4
Cash used for business combinations (see Note 8)	(1,220.2)	(73.7)
Acquisition of intangible assets	--	(1.4)
Investments in unconsolidated affiliates	(10.2)	(9.8)
Proceeds from asset sales and related transactions	24.1	0.6
Other investing activities	--	1.5
Cash used in investing activities	(1,891.8)	(887.3)
Financing activities:		
Borrowings under debt agreements	3,538.8	3,544.4
Repayments of debt	(2,215.0)	(3,023.6)
Debt issuance costs	(14.8)	(5.4)
Cash distributions paid to partners	(830.9)	(566.1)
Unit option-related reimbursements to EPCO	(2.2)	(0.3)
Cash distributions paid to noncontrolling interests	(36.6)	(210.6)
Cash contributions from noncontrolling interests	1.9	124.3
Net cash proceeds from issuance of common units	990.1	398.6
Cash proceeds from exercise of unit options	1.6	0.2
Acquisition of treasury units	(3.0)	--
Monetization of interest rate derivative instruments	1.3	--
Cash provided by financing activities	1,431.2	261.5
Effect of exchange rate changes on cash	0.1	(2.2)
Net change in cash and cash equivalents	439.7	9.2
Cash and cash equivalents, January 1	54.7	61.7
Cash and cash equivalents, June 30	$ 494.5	$ 68.7

See Notes to Unaudited Condensed Consolidated Financial Statements.

*See Note 1 for information regarding these recast amounts and basis of financial statement presentation.

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED EQUITY
(See Note 11 for Unit History, Detail of Changes in Limited Partners' Equity and Accumulated Other Comprehensive Loss)
(Dollars in millions)

	Enterprise Products Partners L.P.				
	Limited Partners	General Partner	Accumulated Other Comprehensive Loss	Noncontrolling Interest	Total
Balance, December 31, 2009	$ 9,329.7	$ 190.8	$ (8.4)	$ 530.2	$ 10,042.3
Net income	611.7	123.3	--	32.1	767.1
Operating lease expenses paid by EPCO	0.3	--	--	--	0.3
Cash distributions paid to partners	(705.7)	(125.2)	--	--	(830.9)
Unit option-related reimbursements to EPCO	(2.2)	--	--	--	(2.2)
Cash distributions paid to noncontrolling interests	--	--	--	(36.6)	(36.6)
Net cash proceeds from issuance of common units	970.3	19.8	--	--	990.1
Cash proceeds from exercise of unit options	1.6	--	--	--	1.6
Cash contributions from noncontrolling interests	--	--	--	1.9	1.9
Amortization of equity awards	17.9	0.3	--	0.2	18.4
Acquisition of treasury units	(3.0)	--	--	--	(3.0)
Foreign currency translation adjustment	--	--	(0.2)	--	(0.2)
Cash flow hedges	--	--	(23.7)	1.4	(22.3)
Other	0.2	(0.2)	(0.9)	(0.2)	(1.1)
Balance, June 30, 2010	$ 10,220.8	$ 208.8	$ (33.2)	$ 529.0	$ 10,925.4

	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)	$ 3,206.4	$ 9,295.9
Net income	333.3	78.6	--	116.1	528.0
Operating lease expenses paid by EPCO	0.3	--	--	--	0.3
Cash distributions paid to partners	(484.4)	(81.7)	--	--	(566.1)
Unit option-related reimbursements to EPCO	(0.3)	--	--	--	(0.3)
Cash distributions paid to noncontrolling interests	--	--	--	(210.6)	(210.6)
Deconsolidation of Texas Offshore Port System (see Note 1)	--	--	--	(33.4)	(33.4)
Net cash proceeds from issuance of common units	390.6	8.0	--	--	398.6
Cash proceeds from exercise of unit options	0.2	--	--	--	0.2
Cash contributions from noncontrolling interests	--	--	--	124.3	124.3
Amortization of equity awards	8.0	0.1	--	2.0	10.1
Foreign currency translation adjustment	--	--	0.6	--	0.6
Cash flow hedges	--	--	(34.3)	3.6	(30.7)
Other	--	--	--	(0.1)	(0.1)
Balance, June 30, 2009*	$ 6,310.8	$ 128.6	$ (130.9)	$ 3,208.3	$ 9,516.8

See Notes to Unaudited Condensed Consolidated Financial Statements.
*See Note 1 for information regarding these recast amounts and basis of financial statement presentation.

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

SIGNIFICANT RELATIONSHIPS REFERENCED IN THESE NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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. Enterprise Products Partners conducts substantially all of its business through EPO and its consolidated subsidiaries. References to "EPGP" mean Enterprise Products GP, LLC, which is our general partner.

References to "Duncan Energy Partners" mean Duncan Energy Partners L.P., which is a consolidated subsidiary of EPO. Duncan Energy Partners 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 "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 "Enterprise GP Holdings" mean Enterprise GP Holdings L.P., a publicly traded Delaware limited partnership, the units of which are listed on the NYSE under the ticker symbol "EPE." Enterprise GP Holdings owns EPGP. The general partner of Enterprise GP Holdings is EPE Holdings, LLC ("EPE Holdings"), which is a wholly owned subsidiary of Dan Duncan LLC. The membership interests of Dan Duncan LLC are owned of record by a voting trust formed on April 26, 2006, pursuant to the Dan Duncan LLC Voting Trust Agreement dated April 26, 2006 (the "DD LLC Voting Trust Agreement"), among Dan Duncan LLC and Dan L. Duncan (as the record owner of all of the membership interests of Dan Duncan LLC immediately prior to the entering into of the DD LLC Voting Trust Agreement and as the initial sole voting trustee).

Immediately upon Mr. Duncan's death on March 29, 2010, voting and dispositive control of all of the membership interests of Dan Duncan LLC was transferred pursuant to the DD LLC Voting Trust Agreement to three voting trustees. The current voting trustees under the DD LLC Voting Trust Agreement (the "DD LLC Trustees") are: (i) Randa Duncan Williams, Mr. Duncan's oldest daughter, who is also a director of EPE Holdings; (ii) Dr. Ralph S. Cunningham, who is currently the President and Chief Executive Officer ("CEO") of EPE Holdings; and (iii) Richard H. Bachmann, who is currently an Executive Vice President, the Chief Legal Officer and Secretary of EPGP and one of three managers of Dan Duncan LLC. Dr. Cunningham and Mr. Bachmann are also currently directors of EPE Holdings.

The DD LLC Voting Trust Agreement requires that there always be two "Independent Voting Trustees" serving. If Mr. Bachmann or Dr. Cunningham fail to qualify or cease to serve, then the substitute or successor Independent Voting Trustee(s) will be appointed by the then-serving Independent Voting Trustee, provided that if no Independent Voting Trustee is then serving or if a vacancy in a trusteeship of an Independent Voting Trustee is not filled within ninety days of the vacancy's occurrence, the CEO of EPGP will appoint the successor Independent Voting Trustee(s).

The DD LLC Voting Trust Agreement also provides for a "Duncan Voting Trustee." The Duncan Voting Trustee is appointed by the children of Mr. Duncan acting by a majority or, if less than three children of Mr. Duncan are then living, unanimously. If for any reason no descendent of Mr. Duncan is appointed as the Duncan Voting Trustee, then such trusteeship will remain vacant until such time as a Duncan Voting Trustee is appointed in the manner provided above. If a Duncan Voting Trustee for any reason ceases to serve, his or her successor shall be appointed by the children of Mr. Duncan acting by majority or, if less than three children of Mr. Duncan are then living, unanimously. Ms. Williams is currently the Duncan Voting Trustee.

The DD LLC Trustees are required to treat for all purposes whatsoever the member party to the DD LLC Voting Trust Agreement as the beneficial owner of the membership interests of Dan Duncan

LLC. The estate of Mr. Duncan became the sole member party to the DD LLC Voting Trust Agreement upon the death of Mr. Duncan on March 29, 2010. However, the DD LLC Trustees collectively are the record owners of the Dan Duncan LLC membership interests and possess and are entitled to exercise all rights and powers of absolute ownership thereof and to vote, assent or consent with respect thereto and to take party in and consent to any corporate or members' actions (except those actions, if any, to which the DD LLC Trustees may not legally consent) and subject to the provisions of the DD LLC Voting Trust Agreement, to receive dividends and distributions on the Dan Duncan LLC membership interests. Except as otherwise provided in the DD LLC Voting Trust Agreement, all actions taken by the DD LLC Trustees are by majority vote.

The DD LLC Trustees serve in such capacity without compensation, but they are entitled to incur reasonable charges and expenses deemed necessary and proper for administering the DD LLC Voting Trust Agreement and to reimbursement and indemnification.

The DD LLC Voting Trust Agreement will terminate when (i) the descendants of Mr. Duncan, and entities directly or indirectly controlled by or held for the benefit of any such descendant, no longer own any capital stock of EPCO (as defined below); or (ii) upon such earlier date designated by the DD LLC Trustees by an instrument in writing delivered to the member party to the DD LLC Voting Trust Agreement.

On April 27, 2010, the independent co-executors for the estate of Mr. Duncan were appointed by the probate court. The independent co-executors are Mr. Bachmann, Dr. Cunningham and Ms. Williams, who are the same persons as the current DD LLC Trustees and voting trustees under a separate voting trust agreement relating to a majority of EPCO's outstanding shares with voting rights (as more fully described below).

References to "EPCO" mean Enterprise Products Company (formerly EPCO, Inc.) and its privately held affiliates. Prior to Mr. Duncan's death, we, EPO, Duncan Energy Partners, DEP GP, EPGP, Enterprise GP Holdings and EPE Holdings were affiliates under the common control of Mr. Duncan, since he was the controlling shareholder of EPCO and the controlling member of Dan Duncan LLC. A majority of the outstanding voting capital stock of EPCO is owned of record by a voting trust formed on April 26, 2006, pursuant to the EPCO Inc. Voting Trust Agreement (the "EPCO Voting Trust Agreement"), among EPCO and Mr. Duncan (as the record owner of a majority of the outstanding voting capital stock of EPCO immediately prior to the entering into of the EPCO Voting Trust Agreement and as the initial sole voting trustee).

Immediately upon Mr. Duncan's death, voting and dispositive control of such majority of the outstanding voting capital stock of EPCO was transferred pursuant to the EPCO Voting Trust Agreement to three voting trustees (the "EPCO Trustees"). The current EPCO Trustees are: (i) Ms. Williams, who serves as Chairman of EPCO; (ii) Dr. Cunningham, who serves as a Vice Chairman of EPCO; and (iii) Mr. Bachmann, who serves as the President, CEO and Chief Legal Officer of EPCO. Ms. Williams, Dr. Cunningham and Mr. Bachmann are also currently directors of EPCO. The current EPCO Trustees are the same as the current DD LLC Trustees, which control Dan Duncan LLC. The current EPCO Trustees are also the same persons as the individuals appointed on April 27, 2010 as the independent co-executors of the estate of Mr. Duncan. At June 30, 2010, Dan Duncan LLC and EPCO beneficially owned approximately 18% and 57%, respectively, of the outstanding units representing limited partner interests of Enterprise GP Holdings.

References to "TEPPCO" and "TEPPCO GP" mean TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (which is the general partner of TEPPCO), respectively, prior to their mergers with our subsidiaries on October 26, 2009. We refer to such related mergers both individually and in the aggregate as the ("TEPPCO Merger").

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") and, effective May 26, 2010, Regency Energy Partners LP ("RGNC"). 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." ETP is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "ETP." RGNC is a publicly traded Delaware limited partnership, the common units of which are traded on the NASDAQ stock market under the ticker symbol "RGNC." The general partner of Energy Transfer Equity is LE GP, LLC.

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

Note 1. Partnership Operations and Basis of Presentation

General

We are a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "EPD." We were formed in April 1998 to own and operate certain natural gas liquids ("NGLs") related businesses of EPCO. We are a leading North American provider of midstream energy services to producers and consumers of natural gas, NGLs, crude oil, refined products and petrochemicals. 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 with domestic consumers and international markets. The partnership's assets include: 49,100 miles of onshore and offshore pipelines; approximately 200 million barrels ("MMBbls") of storage capacity for NGLs, refined products and crude oil; and 27 billion cubic feet ("Bcf") of natural gas storage capacity.

Our midstream energy operations include: natural gas transportation, gathering, processing and storage; NGL transportation, fractionation, storage, and import and export terminaling; crude oil and refined products transportation, storage, and terminaling; offshore production platforms; petrochemical transportation and storage; and a marine transportation business that operates primarily on the United States inland and Intracoastal Waterway systems and in the Gulf of Mexico. We have five reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services and (v) Petrochemical & Refined Products Services. Our business segments reflect the manner in which these businesses are managed and reviewed by the CEO of our general partner. See Note 12 for additional information regarding our business segments.

We are owned 98% by our limited partners and 2% by our general partner, EPGP. We, EPGP, Enterprise GP Holdings, EPE Holdings, EPCO and Dan Duncan LLC are affiliates and under the collective common control of the DD LLC Trustees and the EPCO Trustees. We have no employees. All of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to an administrative services agreement, or ASA, or other service providers. See Note 13 for information regarding the ASA and related party matters.

Our results of operations for the three and six months ended June 30, 2010 are not necessarily indicative of results expected for the full year. 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 the Notes thereto should be read in conjunction with the Audited Consolidated Financial Statements and Notes thereto included in our annual report on Form 10-K for the year ended December 31, 2009 (the "2009 Form 10-K").

Consolidation of Duncan Energy Partners

For financial reporting purposes, we consolidate the financial statements of 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. 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 nor EPO have any obligation for the payment of interest or repayment of borrowings incurred by Duncan Energy Partners.

TEPPCO Merger and Basis of Presentation

On October 26, 2009, the related mergers of our wholly owned subsidiaries with TEPPCO and TEPPCO GP were completed. As a result, our consolidated financial statements and business segments were recast to reflect the TEPPCO Merger. Under terms of the merger agreements, TEPPCO and TEPPCO GP became wholly owned subsidiaries of ours, and each of TEPPCO's unitholders, except for a privately held affiliate of EPCO, were entitled to receive 1.24 of our common units for each TEPPCO unit they owned. In total, we issued an aggregate of 126,932,318 common units and 4,520,431 Class B units (described below) as consideration in the TEPPCO Merger for both TEPPCO units and the TEPPCO GP membership interests. On October 27, 2009, our TEPPCO and TEPPCO GP equity interests were contributed to EPO, and TEPPCO and TEPPCO GP became wholly owned subsidiaries of EPO.

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

Under the terms of the TEPPCO Merger agreements, Enterprise GP Holdings received 1,331,681 of our common units and an increase in the capital account of EPGP to maintain its 2% general partner interest in us as consideration for 100% of the membership interests of TEPPCO GP.

Due to common control considerations, the TEPPCO Merger was accounted for at historical costs as a reorganization of entities under common control in a manner similar to a pooling of interests. Our consolidated financial statements for periods prior to the TEPPCO Merger reflect the combined financial information of Enterprise Products Partners, TEPPCO and TEPPCO GP on a 100% basis. Third-party and related party ownership interests in TEPPCO and TEPPCO GP are presented as "Former owners of TEPPCO," which is a component of noncontrolling interest.

There was no change in net income attributable to Enterprise Products Partners L.P. for periods prior to the TEPPCO Merger since the net income attributable to TEPPCO and TEPPCO GP for these periods was allocated to noncontrolling interests. Additionally, there was no change in our reported earnings per unit ("EPU") for such periods. See Note 12 for a reconciliation of our recast consolidated revenues and total segment gross operating margin, which is a non-generally accepted accounting principle ("non-GAAP") financial performance measure, to our pre-merger reported amounts.

Deconsolidation of Texas Offshore Port System

In August 2008, we, including TEPPCO, together with Oiltanking Holding Americas, Inc. ("Oiltanking") formed the Texas Offshore Port System partnership ("TOPS"). In April 2009, we and TEPPCO dissociated from TOPS. As a result, our operating costs and expenses and net income for the second quarter of 2009 include a non-cash charge of $68.4 million. This loss represents the forfeiture of our cumulative investment, including that of TEPPCO, in TOPS through the date of dissociation. The impact on net income attributable to Enterprise Products Partners L.P. was approximately $34.2 million, as $34.2 million of this loss was absorbed by noncontrolling interests in consolidation (i.e., by the former owners of TEPPCO).

On a recast basis, we consolidated the financial statements of TOPS with those of our own since TEPPCO and we held a majority of the ownership interests and voting control of TOPS. Oiltanking's interest in the joint venture was accounted for as a noncontrolling interest. As a result of our dissociation from TOPS, we discontinued the consolidation of TOPS during the second quarter of 2009. The effect of deconsolidation was to remove the accounts of TOPS, including Oiltanking's noncontrolling interest of $33.4 million, from our books and records, after reflecting the $68.4 million aggregate write-off of the investments related to the deconsolidation.

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, revenue and expenses) and disclosures regarding 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. Any future changes in facts and circumstances may require updated estimates, which, in turn, could have a significant impact on our financial statements.

Fair Value Information

Cash and cash equivalents and restricted cash, accounts receivable, accounts payable and accrued expenses and other current liabilities (excluding derivative instruments) 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, 2010		December 31, 2009	
Financial Instruments	**Carrying Value**	**Fair Value**	**Carrying Value**	**Fair Value**
Financial assets:				
Cash and cash equivalents and restricted cash	$ 513.6	$ 513.6	$ 118.3	$ 118.3
Accounts receivable	2,943.3	2,943.3	3,137.4	3,137.4
Financial liabilities:				
Accounts payable and accrued expenses	3,948.6	3,948.6	4,101.4	4,101.4
Other current liabilities (excluding derivative instruments)	331.7	331.7	341.6	341.6
Fixed-rate debt (principal amount)	12,032.7	12,665.8	10,586.7	11,056.2
Variable-rate debt	594.8	594.8	710.3	710.3

Recent Accounting Developments

In November 2008, the SEC released a proposed roadmap regarding the potential use by U.S. issuers of financial statements prepared in accordance with International Financial Reporting Standards ("IFRS"). IFRS consist of accounting standards published by the International Accounting Standards Board ("IASB"), which is based in London, England. In February 2010, the SEC expressed its continuing support for a single set of high-quality globally accepted accounting standards and established a general work plan that sets forth areas and factors the SEC will consider before requiring domestic public companies to transition to IFRS. Currently, the Financial Accounting Standards Board (or "FASB," based in Norwalk, Connecticut) and the IASB are working both individually and jointly on a number of accounting standard convergence projects that, if finalized in 2011, would bring about a significant shift in the accounting and financial reporting landscape. These projects include a broad range of topics such as financial statement presentation, accounting for leases, revenue recognition, financial instruments, consolidations and fair value measurements.

The SEC will make a determination in 2011 regarding the mandatory adoption of IFRS with the expectation that any decision to adopt IFRS would allow U.S. issuers four to five years to transition from current U.S. GAAP. We continue to monitor developments in the potential implementation of IFRS and the ongoing convergence projects of the FASB and IASB. We will evaluate the impact that any definitive accounting guidance may have on our financial statements once this information is finalized by the appropriate standard setting organizations, including the SEC.

Restricted Cash

Restricted cash represents amounts held in connection with our commodity derivative instruments portfolio and related physical natural gas and NGL purchases. Additional cash may be restricted to maintain this portfolio as commodity prices fluctuate or deposit requirements change. At June 30, 2010 and December 31, 2009, our restricted cash amounts were $19.1 million and $63.6 million, respectively. Our restricted cash balances have decreased since December 31, 2009 due to a reduction in margin requirements related to our commodity hedging activities. See Note 4 for information regarding our derivative instruments and hedging activities.

Note 3. Equity-based Awards

An allocated portion of the fair value of EPCO's equity-based awards is charged to us under the ASA. The following table summarizes the expense we recognized in connection with equity-based awards for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2010	2009	2010	2009
Restricted unit awards (1)	$ 7.6	$ 3.8	$ 12.9	$ 6.2
Unit option awards (1)	0.9	0.6	1.8	0.7
Unit appreciation rights (2)	0.1	--	0.2	--
Phantom units (2)	0.1	0.1	0.1	0.1
Profits interests awards (1)	1.8	2.0	3.6	3.4
Total compensation expense	$ 10.5	$ 6.5	$ 18.6	$ 10.4

(1) Accounted for as equity-classified awards.
(2) Accounted for as liability-classified awards.

The fair value of an equity-classified award (e.g., a restricted unit award) is amortized to earnings over the requisite service or vesting period. Compensation expense for liability-classified awards (e.g., unit appreciation rights ("UARs")) is recognized over the requisite service or vesting period of an award based on the fair value of the award remeasured at each reporting period. Liability-classified awards are settled in cash upon vesting.

At June 30, 2010, EPCO's long-term incentive plans applicable to our operations were the Enterprise Products 1998 Long-Term Incentive Plan, the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan and the 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan. In addition, there were unvested awards outstanding under an inactive plan, the Enterprise Products 2006 TPP Long-Term Incentive Plan ("2006 Plan"). EPCO's equity-based awards also include profits interests in the Employee Partnerships.

When employees exercise unit options, we reimburse EPCO for the cash difference between the strike price paid by the employee and the actual purchase price paid by EPCO for the common units issued to the employee. In addition, we reimburse EPCO for certain amounts recorded in connection with EPCO Unit (one of the Employee Partnerships). Beginning in February 2009, the ASA was amended to provide that we and other affiliates of EPCO will reimburse EPCO for our allocated share of distributions of cash or securities made to the Class B limited partners of EPCO Unit. Except for the foregoing, we are not responsible for reimbursing EPCO for any of the costs associated with equity awards.

Restricted Unit Awards

Restricted unit awards allow recipients to acquire (at no cost to the recipient apart from service or other conditions) limited partner units once a defined vesting period expires, subject to customary forfeiture provisions. Restricted unit awards may be denominated in our common units or those of Duncan Energy Partners depending on the issuer of the award. Restricted unit awards issued prior to 2010 cliff vest generally four years from the date of grant. Beginning with awards issued in 2010, restricted unit awards are subject to graded vesting provisions in which one-fourth of each award vests on the first, second, third and fourth anniversaries of the date of grant. As used in the context of EPCO's long-term incentive plans, the term "restricted unit" represents a time-vested unit. Such awards are non-vested until the required service period expires.

The fair value of a restricted unit award is based on the market price per unit of the underlying security on the date of grant. Compensation expense is recognized based on the grant date fair value, net of an allowance for estimated forfeitures, over the requisite service or vesting period.

The following table summarizes information regarding restricted unit awards for the periods indicated:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Enterprise Products Partners L.P. restricted unit awards:		
Restricted units at December 31, 2009	2,720,882	$ 27.70
Granted (2,3)	1,332,875	$ 32.26
Vested (3)	(322,228)	$ 25.12
Forfeited	(93,148)	$ 29.51
Restricted units at June 30, 2010	3,638,381	$ 29.69
Duncan Energy Partners L.P. restricted unit awards:		
Restricted units at December 31, 2009	--	
Granted (3,4)	6,348	$ 25.26
Vested (3)	(6,348)	$ 25.26
Restricted units at June 30, 2010	--	

(1) Determined by dividing the aggregate grant date fair value of awards before an allowance for forfeitures by the number of awards issued.
(2) Aggregate grant date fair value of restricted unit awards denominated in our common units was $43.0 million based on grant date market price of our common units ranging from $32.00 to $32.27 per unit. Estimated forfeiture rates ranging between 4.6% and 17% were applied to these awards.
(3) Includes awards granted to the independent directors of the boards of directors of EPGP and DEP GP as part of their annual compensation for 2010. A total of 6,960 and 6,348 restricted unit awards were issued in February 2010 to the independent directors of EPGP and DEP GP, respectively, that immediately vested upon issuance.
(4) Aggregate grant date fair value of restricted unit awards denominated in Duncan Energy Partners' common units was $0.2 million based on a grant date market price of Duncan Energy Partners' common units of $25.26 per unit.

In the aggregate, unrecognized compensation cost of restricted unit awards was $59.6 million at June 30, 2010, of which our allocated share of the cost is currently estimated to be $53.5 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.1 years.

Unit Option Awards

EPCO's long-term incentive plans provide for the issuance of non-qualified incentive options. These option awards may be denominated in our common units or those of Duncan Energy Partners depending on the issuer of the award. When issued, the exercise price of each option award may be no less than the market price of the underlying security on the date of grant. In general, option awards have a vesting period of four years from the date of grant. If option awards are not exercised, these awards generally expire between five and ten years after the date of grant.

The fair value of each unit option is estimated on the date of grant using a Black-Scholes option pricing model, which incorporates various assumptions including expected life of the option, risk-free interest rates, expected distribution yield of the underlying security, and expected unit price volatility. Compensation expense is recognized based on the grant date fair value, net of an allowance for estimated forfeitures, over the vesting period.

The following table presents unit option activity for the periods indicated. As of June 30, 2010, only Enterprise Products Partners has issued unit option awards.

	Number of Units	Weighted-Average Strike Price (dollars/unit)	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (1)
Outstanding at December 31, 2009	3,825,920	$ 26.52		
Granted (2)	785,000	$ 32.26		
Exercised	(222,500)	$ 24.60		
Outstanding at June 30, 2010	4,388,420	$ 27.65	4.3	$ 6.5
Options exercisable at June 30, 2010	635,000	$ 25.11	5.3	$ 6.5

(1) Aggregate intrinsic value reflects fully vested unit options at the date indicated.
(2) Aggregate grant date fair value of these unit options was $2.3 million based on the following assumptions: (i) a weighted-average grant date market price of our common units of $32.26 per unit; (ii) weighted-average expected life of options of 4.9 years; (iii) weighted-average risk-free interest rate of 2.5%; (iv) weighted-average expected distribution yield on our common units of 6.9%; and (v) weighted-average expected unit price volatility on our common units of 23.3%. An estimated forfeiture rate of 17% was applied to awards granted during 2010.

The following table presents additional information regarding unit option awards for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2010	2009	2010	2009
Total intrinsic value of option awards exercised during period	$ 1.3	$ 0.2	$ 2.2	$ 0.3
Cash received from EPCO in connection with the exercise of unit option awards	1.0	0.1	1.6	0.2
Unit option-related reimbursements to EPCO	1.3	0.2	2.2	0.3

In the aggregate, unrecognized compensation cost of unit option awards was $9.1 million at June 30, 2010, of which our allocated share of the cost is currently estimated to be $8.0 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.7 years.

Unit Appreciation Rights

UARs entitle a participant to receive a cash payment on the vesting date equal to the excess, if any, of the fair market value of the underlying security (determined as of a future vesting date) over the grant date fair value of the award. UARs are accounted for as liability awards. The following tables present information regarding UAR awards for the periods indicated:

	UARs Based on Units of		
	Enterprise Products Partners	Enterprise GP Holdings	Total
UARs at December 31, 2009	142,196	90,000	232,196
Settled or forfeited	(10,255)	--	(10,255)
UARs at June 30, 2010	131,941	90,000	221,941

	June 30, 2010	December 31, 2009
Accrued liability for UARs	$ 0.6	$ 0.3

At June 30, 2010, 131,941 UARs had been granted under the 2006 Plan to certain employees of EPCO who work on our behalf. These awards are subject to five year cliff vesting requirements and are expected to settle in 2012. The grant date fair value with respect to these UARs is based on a unit price of $37.00 for our common units. If the employee resigns prior to vesting, the UAR awards are forfeited.

At June 30, 2010, there were 90,000 UARs outstanding that were granted to the independent directors of DEP GP. These UARs cliff vest in 2012. The grant date fair value with respect to these UARs is based on an Enterprise GP Holdings' unit price of $36.68. If a director resigns prior to vesting, his UAR awards are forfeited.

Phantom Unit Awards

Certain of EPCO's long-term incentive plans provide for the issuance of phantom unit awards. These awards are automatically redeemed for cash based on the fair value of the vested portion of phantom units at redemption dates stated in each award. The fair value of each phantom unit award is equal to the closing market price of the underlying security on the redemption date. Each participant is required to redeem their phantom units as they vest, which is typically three to four years from the date the award is granted. Phantom unit awards are accounted for as liability awards.

The following tables present information regarding phantom unit awards for the periods indicated:

Phantom units at December 31, 2009	14,927
Granted	6,200
Vested	(4,327)
Phantom units at June 30, 2010	16,800

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
Liabilities paid for phantom unit awards	$ --	$ 0.3	$ 0.1	$ 1.1

	June 30, 2010	December 31, 2009
Accrued liability for phantom unit awards	$ 0.2	$ 0.2

The 3,472 phantom units outstanding under the TEPPCO 1999 Phantom Unit Retention Plan at December 31, 2009 vested in January 2010 and the plan was terminated.

Profits Interests Awards

As long-term incentive arrangements, EPCO granted its key employees who perform services on behalf of us, EPCO and other affiliated companies, "profits interests" in the Employee Partnerships, all of which are privately held affiliates of EPCO. Profits interests awards entitle each holder to participate in the expected long-term appreciation in value of the equity securities owned by each Employee Partnership. The Employee Partnerships own either units of Enterprise GP Holdings or common units of Enterprise Products Partners or a combination of both. The profits interests awards are subject to customary forfeiture provisions.

Our reimbursements to EPCO in connection with EPCO Unit were $0.1 million during each of the three months ended June 30, 2010 and 2009. During each of the six months ended June 30, 2010 and 2009, our reimbursements to EPCO in connection with EPCO Unit were $0.2 million.

In August 2010, the Employee Partnerships were liquidated. We expect to recognize approximately $24 million of expense during the third quarter of 2010 in connection with these liquidations. Of this expense amount, we estimate that approximately $18 million will be non-cash.

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

In the course of our normal business operations, we are exposed to certain risks, including changes in interest rates, commodity prices and, to a limited extent, foreign exchange rates. In order to manage risks associated with certain identifiable and anticipated transactions, we use derivative instruments.

Derivatives are instruments whose fair value is determined by changes in a specified benchmark such as interest rates, commodity prices or currency values. Fair value is generally defined as the amount at which a derivative instrument could be exchanged in a current transaction between willing parties, not in a forced sale. Typical derivative instruments include futures, forward contracts, swaps, options and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities.

We are required to recognize derivative instruments at fair value as either assets or liabilities on the balance sheet. While all derivatives are required to be reported at fair value on the balance sheet, changes in fair value of the derivative instruments are reported in different ways depending on the nature and effectiveness of the hedging activities to which they relate. 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, gains and losses for 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 (loss) and is reclassified into earnings when the forecasted transaction affects earnings.

- Foreign currency exposure - A foreign currency hedge can be treated as either a fair value hedge or a cash flow hedge depending on the risk being hedged.

An effective hedge relationship is one in which the change in fair value of a derivative instrument can be expected to offset 80% to 125% of the changes in fair value of a hedged item at inception and throughout the life of the hedging relationship. The effective portion of a hedge relationship 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 relationship 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.

A contract designated as a cash flow hedge of an anticipated transaction that is probable of not occurring is immediately recognized in earnings.

Certain of our derivative instruments do not qualify for hedge accounting treatment; therefore, they are accounted for using mark-to-market accounting.

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 charged on borrowings under certain consolidated debt agreements. This strategy is a component in controlling our cost of capital associated with such borrowings.

The following table summarizes our interest rate derivative instruments outstanding at June 30, 2010:

Hedged Transaction	Number and Type of Derivative(s) Employed	Notional Amount	Period of Hedge	Rate Swap	Accounting Treatment
Enterprise Products Partners:					
Senior Notes C	1 fixed-to-floating swap	$100.0	1/04 to 2/13	6.4% to 2.3%	Fair value hedge
Senior Notes G	3 fixed-to-floating swaps	$300.0	10/04 to 10/14	5.6% to 1.4%	Fair value hedge
Senior Notes P	7 fixed-to-floating swaps	$400.0	6/09 to 8/12	4.6% to 2.7%	Fair value hedge
Duncan Energy Partners:					
Variable-rate borrowings	3 floating-to-fixed swaps	$175.0	9/07 to 9/10	0.5% to 4.6%	Cash flow hedge

Interest rate swaps exchange the stated interest rate paid on a notional amount of debt for a fixed or floating interest rate stipulated in the derivative instrument. Our interest rate swaps associated with existing debt obligations resulted in a decrease in interest expense of $4.6 million and $0.4 million for the three months ended June 30, 2010 and 2009, respectively. For the six months ended June 30, 2010 and 2009, such swaps resulted in a decrease in interest expense of $8.9 million and an increase in interest expense of $0.2 million, respectively.

The following table summarizes our forward starting interest rate swaps outstanding at June 30, 2010, which hedge the expected underlying benchmark interest rates related to forecasted issuances of debt:

Hedged Transaction	Number and Type of Derivatives Employed	Notional Amount	Expected Termination Date	Average Rate Locked	Accounting Treatment
Future debt offering	3 forward starting swaps	$250.0	2/11	3.7%	Cash flow hedge
Future debt offering	10 forward starting swaps	$500.0	2/12	4.5%	Cash flow hedge
Future debt offering	3 forward starting swaps	$150.0	8/12	4.0%	Cash flow hedge
Future debt offering	4 forward starting swaps	$400.0	3/13	4.1%	Cash flow hedge

In May 2010, we settled a forward starting swap with a notional amount of $50.0 million and recognized a gain of $1.3 million in other comprehensive income. This amount will be amortized to earnings using the effective interest method over the estimated term of the underlying fixed-rate debt.

Commodity Derivative Instruments

The prices of natural gas, NGLs, crude oil, refined products and certain petrochemical products are subject to fluctuations in response to changes in supply and demand, market conditions and a variety of additional factors that are beyond our control. In order to manage the price risk associated with certain exposures, we enter into commodity derivative instruments such as physical forward agreements, futures contracts, fixed-for-float swaps, basis swaps and options contracts. The following table summarizes our commodity derivative instruments outstanding at June 30, 2010:

	Volume (1)		**Accounting**
Derivative Purpose	**Current**	**Long-Term** (2)	**Treatment**
Derivatives designated as hedging instruments:			
Enterprise Products Partners:			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction (“PTR”) (3)	27.1 Bcf	n/a	Cash flow hedge
Forecasted NGL sales (4)	8.0 MMBbls	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchases of NGLs	1.5 MMBbls	n/a	Cash flow hedge
Inventory management - NGLs	0.1 MMBbls	n/a	Cash flow hedge
Forecasted sales of octane enhancement products	2.1 MMBbls	0.4 MMBbls	Cash flow hedge
Natural gas marketing:			
Natural gas storage inventory management activities	3.1 Bcf	1.2 Bcf	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products	7.5 MMBbls	0.7 MMBbls	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products	9.4 MMBbls	1.2 MMBbls	Cash flow hedge
Crude oil marketing:			
Forecasted purchases of crude oil	1.2 MMBbls	n/a	Cash flow hedge
Forecasted sales of crude oil	2.6 MMBbls	n/a	Cash flow hedge
Duncan Energy Partners:			
Forecasted sales of natural gas	0.4 Bcf	n/a	Cash flow hedge
Derivatives not designated as hedging instruments:			
Enterprise Products Partners:			
Natural gas risk management activities (5,6)	384.2 Bcf	73.9 Bcf	Mark-to-market
Crude oil risk management activities (6)	0.5 MMBbls	n/a	Mark-to-market
Duncan Energy Partners:			
Natural gas risk management activities (6)	0.5 Bcf	n/a	Mark-to-market

(1) Volume for derivatives designated as hedging instruments reflects the total amount of volumes hedged whereas volume for derivatives not designated as hedging instruments reflects the absolute value of derivative notional volumes.

(2) The maximum term for derivatives included in the long-term column is December 2012.

(3) PTR represents the British thermal unit equivalent of the NGLs extracted from natural gas by a processing plant, and includes the natural gas used as plant fuel to extract those liquids, plant flare and other shortages.

(4) Excludes 3.7 MMBbls of additional hedges executed under contracts that have been designated as normal sales agreements under current accounting guidance. The combination of these volumes with the 8.0 MMBbls reflected as derivatives in the table above results in a total of 11.7 MMBbls of hedged forecasted NGL sales volumes, which corresponds to the 27.1 Bcf of forecasted natural gas purchase volumes for PTR.

(5) Current and long-term volumes include approximately 142.8 and 10.5 Bcf, respectively, of physical derivative instruments that are predominantly priced at an index plus a premium or minus a discount related to location differences.

(6) Reflects the use of derivative instruments to manage risks associated with transportation, processing and storage assets.

Our predominant hedging strategies are: (i) hedging natural gas processing margins; (ii) hedging anticipated future contracted sales of NGLs, refined products and crude oil associated with volumes held in inventory and (iii) hedging the fair value of natural gas in inventory. The following information summarizes these hedging strategies:

- The objective of our natural gas processing strategy is to hedge an amount of gross margin associated with our gas processing activities. We achieve this objective by using physical and financial instruments to lock in the purchase prices of natural gas consumed as PTR and the sales prices of the related NGL products. This program consists of (i) the forward sale of a portion of our expected equity NGL production at fixed prices through December 2010, which is achieved through the use of forward physical sales contracts and commodity derivative instruments and (ii) the purchase of commodity derivative instruments having a notional amount based on the volume of natural gas expected to be consumed as PTR in the production of such equity NGL production.

- The objective of our NGL, refined products and crude oil sales hedging program is to hedge the margins of anticipated future sales of inventory by locking in sales prices through the use of forward physical sales contracts and commodity derivative instruments.

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

Foreign Currency Derivative Instruments

We are exposed to a nominal amount of foreign currency exchange risk in connection with our NGL and natural gas marketing activities in Canada. As a result, we could be adversely affected by fluctuations in currency rates between the U.S. dollar and Canadian dollar. In order to manage this risk, we may enter into foreign exchange purchase contracts to lock in an exchange rate. Long-term transactions (i.e., those having terms of more than two months) are accounted for as cash flow hedges. Shorter term transactions are accounted for using mark-to-market accounting. At June 30, 2010, our foreign currency derivative instruments portfolio had a notional amount of $6.0 million Canadian. The fair market value of these derivative instruments was a liability of $0.1 million at June 30, 2010.

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, 2010, the aggregate fair value of our over-the-counter derivative instruments in a net liability position was $6.4 million, all of which was subject to a credit rating contingent feature. If our credit ratings were downgraded to Ba2/BB, approximately $1.4 million would be payable as a margin deposit to the counterparties, and if our credit ratings were downgraded to Ba3/BB- or below, approximately $6.4 million would be payable as a margin deposit to the counterparties. Currently, no margin is required to be deposited. The potential for derivatives with contingent features to enter a net liability position may change in the future as commodity 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, 2010		December 31, 2009		June 30, 2010		December 31, 2009	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments								
Interest rate derivatives	Other current assets	$ 28.5	Other current assets	$ 32.7	Other current liabilities	$ 11.5	Other current liabilities	$ 5.5
Interest rate derivatives	Other assets	31.4	Other assets	31.8	Other liabilities	46.9	Other liabilities	2.2
Total interest rate derivatives		59.9		64.5		58.4		7.7
Commodity derivatives	Other current assets	122.0	Other current assets	52.0	Other current liabilities	65.0	Other current liabilities	62.6
Commodity derivatives	Other assets	3.2	Other assets	0.5	Other liabilities	2.8	Other liabilities	1.8
Total commodity derivatives (1)		125.2		52.5		67.8		64.4
Foreign currency derivatives	Other current assets	--	Other current assets	0.2	Other current liabilities	0.1	Other current liabilities	--
Total derivatives designated as hedging instruments		$ 185.1		$ 117.2		$ 126.3		$ 72.1
Derivatives not designated as hedging instruments								
Commodity derivatives	Other current assets	$ 52.4	Other current assets	$ 28.9	Other current liabilities	$ 55.5	Other current liabilities	$ 24.9
Commodity derivatives	Other assets	2.4	Other assets	2.0	Other liabilities	8.7	Other liabilities	2.7
Total commodity derivatives		54.8		30.9		64.2		27.6
Total derivatives not designated as hedging instruments		$ 54.8		$ 30.9		$ 64.2		$ 27.6

(1) Represent commodity derivative instrument transactions that have either 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.

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

Derivatives in Fair Value Hedging Relationships	Location	Gain/(Loss) Recognized in Income on Derivative			
		For the Three Months Ended June 30,		For the Six Months Ended June 30,	
		2010	2009	2010	2009
Interest rate derivatives	Interest expense	$ 11.6	$ (14.9)	$ 19.0	$ (16.2)
Commodity derivatives	Revenue	4.7	(1.0)	2.9	(1.1)
Total		$ 16.3	$ (15.9)	$ 21.9	$ (17.3)

Derivatives in 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,	
		2010	2009	2010	2009
Interest rate derivatives	Interest expense	$ (10.8)	$ 14.3	$ (18.2)	$ 15.6
Commodity derivatives	Revenue	(4.3)	1.0	(2.4)	1.1
Total		$ (15.1)	$ 15.3	$ (20.6)	$ 16.7

The following table presents the effect of our derivative instruments designated as cash flow hedges on our Unaudited Condensed Statements of Consolidated Comprehensive Income and Consolidated Operations for the periods indicated.

Derivatives in Cash Flow Hedging Relationships	**Change in Value Recognized in Other Comprehensive Income on Derivative (Effective Portion)**			
	For the Three Months Ended June 30,		**For the Six Months Ended June 30,**	
	2010	**2009**	**2010**	**2009**
Interest rate derivatives	$ (70.8)	$ 15.8	$ (76.5)	$ 15.1
Commodity derivatives – Revenue	93.5	75.8	86.4	65.8
Commodity derivatives – Operating costs and expenses	(1.5)	(152.4)	(53.3)	(204.4)
Foreign currency derivatives	(0.1)	0.1	(0.2)	(10.5)
Total	$ 21.1	$ (60.7)	$ (43.6)	$ (134.0)

Derivatives in Cash Flow Hedging Relationships	**Location of Gain/(Loss) Reclassified from Accumulated Other Comprehensive Income/Loss into Income (Effective Portion)**	**Amount of Gain/(Loss) Reclassified from Accumulated Other Comprehensive Income/Loss to Income (Effective Portion)**			
		For the Three Months Ended June 30,		**For the Six Months Ended June 30,**	
		2010	**2009**	**2010**	**2009**
Interest rate derivatives	Interest expense	$ (3.3)	$ (2.5)	$ (6.6)	$ (4.8)
Commodity derivatives	Revenue	18.3	4.4	2.5	19.7
Commodity derivatives	Operating costs and expenses	(16.8)	(70.7)	(17.5)	(118.2)
Foreign currency derivatives	Other income	--	--	0.3	--
Total		$ (1.8)	$ (68.8)	$ (21.3)	$ (103.3)

Derivatives in Cash Flow Hedging Relationships	**Location of Gain/(Loss) Recognized in Income on Ineffective Portion of Derivative**	**Amount of Gain/(Loss) Recognized in Income on Ineffective Portion of Derivative**			
		For the Three Months Ended June 30,		**For the Six Months Ended June 30,**	
		2010	**2009**	**2010**	**2009**
Commodity derivatives	Revenue	$ --	$ (0.7)	$ --	$ (0.7)
Commodity derivatives	Operating costs and expenses	3.5	(0.2)	2.9	(1.3)
Total		$ 3.5	$ (0.9)	$ 2.9	$ (2.0)

Over the next twelve months, we expect to reclassify $7.8 million of losses attributable to interest rate derivative instruments from accumulated other comprehensive loss to earnings as an increase in interest expense. Likewise, we expect to reclassify $48.2 million of gains attributable to commodity derivative instruments from accumulated other comprehensive income to earnings, $24.8 million as a decrease in operating costs and expenses and $23.4 million as an increase in revenues.

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

Derivatives Not Designated as Hedging Instruments	Location	Gain/(Loss) Recognized in Income on Derivative			
		For the Three Months Ended June 30,		For the Six Months Ended June 30,	
		2010	2009	2010	2009
Commodity derivatives	Revenue	$ (8.9)	$ 7.0	$ (5.0)	$ 32.5
Commodity derivatives	Operating costs and expenses	--	--	(1.5)	--
Foreign currency derivatives	Other income	--	--	--	(0.1)
Total		$ (8.9)	$ 7.0	$ (6.5)	$ 32.4

Fair Value Measurements

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

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

The characteristics of fair value amounts classified within each level of the hierarchy are described as follows:

- Level 1 fair values are based on quoted prices, which are available in active markets for identical assets or liabilities as of the measurement date. Active markets are defined as those in which transactions for identical assets or liabilities occur with sufficient frequency so as to provide pricing information on an ongoing basis (e.g., the New York Mercantile Exchange). Our Level 1 fair values primarily consist of financial assets and liabilities such as exchange-traded commodity derivative 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 derivative instruments such as forwards, swaps and other instruments transacted on an exchange or over-the-counter and interest rate derivative instruments. The fair values of these derivative instruments are based on observable price quotes for similar products and locations. The fair value of our interest rate derivatives are determined using appropriate financial models that incorporate the implied forward London Interbank Offered Rate yield curve for the same period as the future interest swap settlements.

- Level 3 fair values are based on unobservable inputs. Unobservable inputs are used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Unobservable inputs reflect our 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 to us in the circumstances, which might include our internally developed data. Level 3 inputs are typically used in connection with internally developed valuation methodologies where we make our best estimate of an instrument's fair value. Our Level 3 fair values primarily consist of ethane, normal butane and natural gasoline-based contracts with terms ranging from two months to a year. We rely on price quotes from reputable brokers who publish price quotes on certain products. Whenever possible, we compare these prices to other reputable brokers for the same product in the same market. These prices, when combined with data from our commodity derivative instruments, are used in our models to determine the fair value of such instruments.

The following table sets forth, by level within the fair value hierarchy, our financial assets and liabilities at June 30, 2010. These financial assets and liabilities are measured on a recurring basis and are classified based on the lowest level of input that is significant to their respective fair value measurements. Our assessment of the relative significance of such inputs requires judgment. There were no significant transfers between Levels 1, 2 or 3 during the six months ended June 30, 2010.

	At June 30, 2010			
	Level 1	Level 2	Level 3	Total
Financial assets:				
Interest rate derivative instruments	$ --	$ 59.9	$ --	$ 59.9
Commodity derivative instruments	74.5	47.6	57.9	180.0
Total	$ 74.5	$ 107.5	$ 57.9	$ 239.9
Financial liabilities:				
Interest rate derivative instruments	$ --	$ 58.4	$ --	$ 58.4
Commodity derivative instruments	27.5	66.4	38.1	132.0
Foreign currency derivative instruments	--	0.1	--	0.1
Total	$ 27.5	$ 124.9	$ 38.1	$ 190.5

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

	For the Six Months Ended June 30,	
	2010	2009
Balance, January 1	$ 5.7	$ 32.4
Total gains (losses) included in:		
Net income (1)	(3.6)	12.9
Other comprehensive income (loss)	(8.3)	1.5
Purchases, issuances, settlements – net	3.6	(12.3)
Balance, March 31	(2.6)	34.5
Total gains (losses) included in:		
Net income (1)	16.2	7.7
Other comprehensive income (loss)	22.2	(23.1)
Purchases, issuances, settlements – net	(16.2)	(8.1)
Transfers out of Level 3	0.2	(0.2)
Balance, June 30	$ 19.8	$ 10.8

(1) There were $2.8 million and $2.3 million of unrealized losses included in these amounts for the three and six months ended June 30, 2010, respectively. 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.

Nonfinancial Assets and Liabilities

Certain nonfinancial assets and liabilities are measured at fair value on a nonrecurring basis and are subject to fair value adjustments in certain circumstances (e.g., when there is evidence of impairment). The following table presents the estimated fair value of certain assets carried on our Unaudited Condensed Consolidated Balance Sheet by caption for which a nonrecurring change in fair value has been recorded during the six months ended June 30, 2010:

	Level 3	Impairment Charges
Property, plant and equipment	$ --	$ 1.5

Using appropriate valuation techniques, we adjusted the carrying value of certain of our Onshore Natural Gas Pipelines & Services business segment assets and recorded, in operating costs and expenses, non-cash asset impairment charges of $1.5 million during the six months ended June 30, 2010. During the six months ended June 30, 2009, we adjusted the carrying value of certain of our Petrochemical & Refined Products Services business segment assets and recorded, in operating costs and expenses, non-cash asset impairment charges of $2.3 million.

Note 5. Inventories

Our inventory amounts were as follows at the dates indicated:

	June 30, 2010	December 31, 2009
Working inventory (1)	$ 598.6	$ 466.4
Forward sales inventory (2)	426.9	245.5
Total inventory	$ 1,025.5	$ 711.9

(1) Working inventory is comprised of natural gas, NGLs, crude oil, refined products, lubrication oils and certain petrochemical products that are either available-for-sale or used in the provision for services. The increase since December 31, 2009 is primarily related to increased marketing activities.
(2) Forward sales inventory consists of identified natural gas, NGL, refined product and crude oil volumes dedicated to the fulfillment of forward sales contracts. The increase since December 31, 2009 is primarily related to higher refined products forward sales volumes.

In those instances where we take ownership of inventory through percent-of-liquids contracts and similar arrangements (as opposed to actually purchasing volumes for cash from third parties), these volumes are valued at market-based prices during the month in which they are acquired.

The following table summarizes our cost of sales and lower of cost or market ("LCM") adjustments for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2010	2009	2010	2009
Cost of sales (1)	$ 6,343.2	$ 4,420.9	$ 13,685.5	$ 8,238.8
LCM adjustments	1.1	1.4	6.9	5.7

(1) Cost of sales is a component of "Operating costs and expenses," as presented on our Unaudited Condensed Statements of Consolidated Operations. Period-to-period fluctuations in these amounts are primarily due to changes in energy commodity prices and sales volumes associated with our marketing activities.

Note 6. Property, Plant and Equipment

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

	Estimated Useful Life in Years	June 30, 2010	December 31, 2009
Plants and pipelines (1)	3-45 (6)	$ 18,491.1	$ 17,681.9
Underground and other storage facilities (2)	5-40 (7)	1,411.8	1,280.5
Platforms and facilities (3)	20-31	637.6	637.6
Transportation equipment (4)	3-10	65.7	60.1
Marine vessels (5)	15-30	588.9	559.4
Land		90.5	82.9
Construction in progress		1,233.1	1,207.2
Total		22,518.7	21,509.6
Less accumulated depreciation		4,186.7	3,820.4
Property, plant and equipment, net		$ 18,332.0	$ 17,689.2

(1) Plants and pipelines include processing plants; NGL, petrochemical, crude oil and natural gas pipelines; terminal loading and unloading facilities; office furniture and equipment; buildings; laboratory and shop equipment and related assets.
(2) Underground and other storage facilities include underground product storage caverns; above ground storage tanks; water wells and related assets.
(3) Platforms and facilities include offshore platforms and related facilities and other associated assets located in the Gulf of Mexico.
(4) Transportation equipment includes vehicles and similar assets used in our operations.
(5) Marine vessels include tow and push boats, barges and related equipment used in our marine transportation business.
(6) In general, the estimated useful lives of major components of this category are as follows: processing plants, 20-35 years; pipelines and related equipment, 5-45 years; terminal facilities, 10-35 years; office furniture and equipment, 3-20 years; buildings, 20-40 years; and laboratory and shop equipment, 5-35 years.
(7) In general, the estimated useful lives of major components of this category are as follows: underground storage facilities, 5-35 years; storage tanks, 10-40 years; and water wells, 5-35 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,	
	2010	2009	2010	2009
Depreciation expense (1)	$ 187.7	$ 169.3	$ 368.0	$ 327.9
Capitalized interest (2)	10.5	10.7	21.0	28.1

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

In May 2010, we recorded approximately $290.1 million of property, plant and equipment in connection with the acquisition of the State Line and Fairplay natural gas gathering systems from subsidiaries of M2 Midstream LLC ("Momentum"). See Note 8 for additional information regarding this business combination.

Asset Retirement Obligations

We record asset retirement obligations ("AROs") related to legal requirements to perform retirement activities as specified in contractual arrangements and/or governmental regulations. In general, our AROs primarily result from (i) right-of-way agreements associated with our pipeline operations, (ii) leases of plant sites and (iii) regulatory requirements triggered by the abandonment or retirement of certain underground storage assets and offshore facilities. In addition, our AROs may result from the renovation or demolition of certain assets containing hazardous substances such as asbestos.

The following table presents information regarding our AROs since December 31, 2009:

ARO liability balance, December 31, 2009	$ 54.8
Revisions in estimated cash flows	3.6
Accretion expense	2.1
Liabilities incurred during period	0.1
Liabilities settled during period	(2.0)
ARO liability balance, June 30, 2010	$ 58.6

Property, plant and equipment at June 30, 2010 and December 31, 2009 includes $21.9 million and $26.7 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived assets. The following table presents forecasted accretion expense associated with our AROs for the periods indicated:

Remainder of 2010	2011	2012	2013	2014
$ 1.8	$ 3.7	$ 4.0	$ 4.3	$ 4.7

Certain of our unconsolidated affiliates had AROs recorded at June 30, 2010 and December 31, 2009 relating to contractual agreements and regulatory requirements. These amounts were immaterial to our consolidated financial statements.

Note 7. Investments in Unconsolidated Affiliates

We hold ownership interests in a number of midstream energy businesses that are accounted for using the equity method of accounting. The following table presents our investments in unconsolidated affiliates (according to the business segment to which they relate) and our ownership interests at the dates indicated:

	Ownership Interest at June 30, 2010	June 30, 2010	December 31, 2009
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C.	13.1%	$ 30.6	$ 32.6
K/D/S Promix, L.L.C. ("Promix")	50%	51.7	48.9
Baton Rouge Fractionators LLC	32.2%	22.3	22.2
Skelly-Belvieu Pipeline Company, L.L.C.	50%	34.0	37.9
Onshore Natural Gas Pipelines & Services:			
Evangeline (1)	49.5%	5.8	5.6
White River Hub, LLC	50%	26.6	26.4
Onshore Crude Oil Pipelines & Services:			
Seaway Crude Pipeline Company ("Seaway")	50%	175.9	178.5
Offshore Pipelines & Services:			
Poseidon Oil Pipeline Company, L.L.C. ("Poseidon")	36%	58.5	61.7
Cameron Highway Oil Pipeline Company	50%	235.6	239.6
Deepwater Gateway, L.L.C.	50%	100.3	101.8
Neptune Pipeline Company, L.L.C.	25.7%	54.8	53.8
Petrochemical & Refined Products Services:			
Baton Rouge Propylene Concentrator, LLC	30%	10.8	11.1
Centennial Pipeline LLC ("Centennial")	50%	62.6	66.7
Other (2)	Various	3.7	3.8
Total		$ 873.2	$ 890.6

(1) Evangeline refers to our ownership interests in Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp., collectively.
(2) Other unconsolidated affiliates include a 50% interest in a propylene pipeline extending from Mont Belvieu, Texas to La Porte, Texas and a 25% interest in a company that provides logistics communications solutions between petroleum pipelines and their customers.

On occasion, the price we pay to acquire an ownership interest in a company exceeds the underlying book value of the capital accounts we acquire. Such excess cost amounts are included within the carrying values of our investments in unconsolidated affiliates. The following table presents the unamortized excess cost amounts by business segment at the dates indicated:

	June 30, 2010	December 31, 2009
NGL Pipelines & Services	$ 26.1	$ 27.1
Onshore Crude Oil Pipelines & Services	20.0	20.4
Offshore Pipelines & Services	16.7	17.3
Petrochemical & Refined Products Services	3.1	4.0
Total	$ 65.9	$ 68.8

Such excess cost amounts are attributable to the underlying tangible and amortizable intangible assets of the related unconsolidated affiliates. We amortize the excess cost amounts (as a reduction in equity earnings) in a manner similar to depreciation. The following table presents our amortization of such excess cost amounts by business segment for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2010	2009	2010	2009
NGL Pipelines & Services	$ 0.3	$ 0.3	$ 0.5	$ 0.5
Onshore Crude Oil Pipelines & Services	0.2	0.2	0.4	0.4
Offshore Pipelines & Services	0.3	0.3	0.6	0.6
Petrochemical & Refined Products Services	0.2	0.7	0.9	2.0
Total	$ 1.0	$ 1.5	$ 2.4	$ 3.5

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,	
	2010	2009	2010	2009
NGL Pipelines & Services	$ 3.7	$ 2.3	$ 7.0	$ 3.5
Onshore Natural Gas Pipelines & Services	0.9	1.4	2.2	2.5
Onshore Crude Oil Pipelines & Services	3.6	2.9	5.9	6.2
Offshore Pipelines & Services	11.1	6.8	22.9	11.5
Petrochemical & Refined Products Services	(2.6)	(3.8)	(5.3)	(6.7)
Total	$ 16.7	$ 9.6	$ 32.7	$ 17.0

Summarized Income Statement Information of Unconsolidated Affiliates

The following tables present unaudited income statement information (on a 100% basis) of our unconsolidated affiliates, aggregated by the business segments to which they relate, for the periods indicated:

	Summarized Income Statement Information for the Three Months Ended					
	June 30, 2010			June 30, 2009		
	Revenues	Operating Income (Loss)	Net Income (Loss)	Revenues	Operating Income (Loss)	Net Income (Loss)
NGL Pipelines & Services	$ 74.7	$ 13.4	$ 13.4	$ 46.1	$ 7.8	$ 7.9
Onshore Natural Gas Pipelines & Services	53.7	1.9	1.9	44.3	3.0	2.7
Onshore Crude Oil Pipelines & Services	22.0	10.8	10.8	21.8	10.0	10.1
Offshore Pipelines & Services	51.4	26.8	26.7	33.8	13.4	13.2
Petrochemical & Refined Products Services	15.6	(2.6)	(6.5)	13.4	(0.9)	(3.5)

	Summarized Income Statement Information for the Six Months Ended					
	June 30, 2010			June 30, 2009		
	Revenues	Operating Income (Loss)	Net Income (Loss)	Revenues	Operating Income	Net Income (Loss)
NGL Pipelines & Services	$ 149.5	$ 26.5	$ 26.4	$ 101.7	$ 12.8	$ 13.0
Onshore Natural Gas Pipelines & Services	96.0	4.4	4.3	82.6	5.1	4.9
Onshore Crude Oil Pipelines & Services	40.5	18.1	18.1	41.5	18.7	18.8
Offshore Pipelines & Services	106.4	56.0	55.4	63.2	14.5	13.7
Petrochemical & Refined Products Services	24.2	(2.0)	(6.8)	28.3	2.8	(2.5)

Note 8. Business Combinations

State Line and Fairplay Natural Gas Gathering Systems

On May 4, 2010, we acquired 100% ownership of the State Line and Fairplay natural gas gathering systems and related assets from Momentum for approximately $1.2 billion in cash. The effective date of the acquisition was May 1, 2010. These systems are located in northwest Louisiana and east Texas and gather natural gas produced from the Haynesville/Bossier Shales and the Cotton Valley and Taylor Sand formations. We used a portion of the net proceeds from our April 2010 equity offering, together with borrowings under EPO's Multi-Year Revolving Credit Facility, to pay for this acquisition.

The State Line system is located in Desoto and Caddo Parishes, Louisiana and Panola County, Texas. The system currently includes approximately 188 miles of natural gas gathering pipelines having an aggregate gathering capacity of approximately 700 million cubic feet per day ("MMcf/d") and two treating facilities. The State Line system began operations in February 2009 and is currently gathering approximately 500 MMcf/d of natural gas. The Fairplay system is located in Rusk, Panola, Gregg and Nacogdoches counties, Texas. The system includes approximately 249 miles of natural gas gathering pipelines (including approximately 62 miles leased from third parties) having an aggregate gathering capacity of approximately 285 MMcf/d. The Fairplay system is currently gathering approximately 175 MMcf/d of natural gas. Operations related to the Fairplay system include natural gas processing activities provided under contract at third-party processing facilities. The State Line and Fairplay systems are supported by long-term acreage dedication agreements totaling approximately 210,000 acres, as well as volumetric commitments from producers.

The addition of the State Line system complements the Haynesville Extension of our Acadian Gas pipeline system. The Haynesville Extension, which is under development, is expected to provide shippers with both production takeaway capacity from the growing Haynesville Shale and flexible options for reaching attractive markets, including access to nine interstate gas pipeline systems. The Fairplay system is expected to extend our asset base through planned future interconnects with our Texas Intrastate System, along with supporting deliveries of NGLs into our Panola pipeline, and to our fractionation, storage and distribution complex in Mont Belvieu, Texas.

On a combined basis, our consolidated revenues and net income from the State Line and Fairplay systems were $26.2 million and $2.5 million, respectively, for the two months we owned these assets.

Pro forma financial information. Since the effective date of the State Line and Fairplay acquisitions was May 1, 2010, our Unaudited Condensed Statements of Consolidated Operations do not include earnings from these businesses prior to this date. The following table presents selected pro forma earnings information for the periods presented as if the acquisitions had been completed on January 1 of each year presented. This pro forma information was prepared using historical financial data for the State Line and Fairplay systems and reflects certain estimates and assumptions made by our management. Our pro forma financial information is not necessarily indicative of what our consolidated financial results would have been had we actually acquired the State Line and Fairplay systems on January 1 of each year presented.

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2010	2009	2010	2009
Pro forma earnings data:				
Revenues	$ 7,557.0	$ 5,460.7	$ 16,153.3	$ 10,375.8
Costs and expenses	7,024.2	5,098.5	15,080.9	9,540.7
Operating income	549.5	371.8	1,105.1	852.1
Net income	374.4	209.3	771.6	520.6
Net income attributable to Enterprise Products Partners L.P.	358.3	183.4	739.5	404.5
Basic earnings per unit:				
As reported basic units outstanding	633.8	458.4	625.9	455.5
Pro forma basic units outstanding	635.9	472.2	633.8	469.3
As reported basic earnings per unit	$ 0.46	$ 0.32	$ 0.97	$ 0.73
Pro forma basic earnings per unit	$ 0.46	$ 0.30	$ 0.96	$ 0.68
Diluted earnings per unit:				
As reported diluted units outstanding	639.1	458.5	631.3	455.6
Pro forma diluted units outstanding	641.2	472.3	639.2	469.4
As reported diluted earnings per unit	$ 0.46	$ 0.32	$ 0.96	$ 0.73
Pro forma diluted earnings per unit	$ 0.46	$ 0.30	$ 0.96	$ 0.68

Marine Crude Oil Transportation Business

On June 1, 2010, we acquired certain marine transportation assets from CTCO Marine Services LLC for $12.0 million in cash. The acquired assets are utilized as part of a crude oil gathering business that provides service between points in the Gulf of Mexico and the inland waterways of coastal Louisiana. This business includes three tug boats and five barges that are a component of our Petrochemical & Refined Products Services business segment. On a pro forma consolidated basis after giving effect to this transaction, our revenues, costs and expenses, operating income, net income attributable to Enterprise Products Partners L.P. and earnings per unit amounts would not have differed materially from those we reported for the three and six months ended June 30, 2010 and 2009.

Purchase Price Allocations

We accounted for our 2010 business combinations using the purchase method of accounting. Accordingly, such costs have been allocated to assets acquired and liabilities assumed based on fair values that were developed using recognized business valuation techniques. The following table depicts the preliminary allocation of the fair value of assets acquired and liabilities assumed at the effective date for each business combination:

	State Line and Fairplay Systems	Marine Crude Oil Transportation Business	Other	Total
Assets acquired in business combination:				
Property, plant and equipment, net	$ 290.1	$ 5.9	$ 2.2	$ 298.2
Identifiable intangible assets	895.0	--	--	895.0
Total assets acquired	1,185.1	5.9	2.2	1,193.2
Liabilities assumed in business combination:				
Current liabilities	(5.2)	--	--	(5.2)
Long-term liabilities	(0.1)	--	--	(0.1)
Total liabilities assumed	(5.3)	--	--	(5.3)
Total assets acquired plus liabilities assumed	1,179.8	5.9	2.2	1,187.9
Total cash used for business combinations	1,206.0	12.0	2.2	1,220.2
Goodwill (see Note 9)	$ 26.2	$ 6.1	$ --	$ 32.3

The State Line and Fairplay property, plant and equipment assets are a component of our Onshore Natural Gas Pipelines & Services business segment. Of the $895.0 million of identifiable intangible assets (i.e., customer relationships) we recorded in connection with this acquisition, $103.4 million is attributable to natural gas processing activities and $791.6 million to natural gas gathering operations. We classify earnings and assets associated with natural gas processing activities as part of our NGL Pipelines & Services segment. Earnings and assets associated with natural gas gathering activities are reported within our Onshore Natural Gas Pipelines & Services segment. See Note 9 for additional information regarding the customer relationship intangible assets we acquired in connection with the State Line and Fairplay systems.

Note 9. Intangible Assets and Goodwill

Identifiable Intangible Assets

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

	June 30, 2010			December 31, 2009		
	Gross Value	Accum. Amort.	Carrying Value	Gross Value	Accum. Amort.	Carrying Value
NGL Pipelines & Services:						
Customer relationship intangibles (1)	$ 340.8	$ (95.9)	$ 244.9	$ 237.4	$ (86.5)	$ 150.9
Contract-based intangibles	321.4	(166.7)	154.7	321.4	(156.7)	164.7
Segment total	662.2	(262.6)	399.6	558.8	(243.2)	315.6
Onshore Natural Gas Pipelines & Services:						
Customer relationship intangibles (1)	1,163.6	(138.1)	1,025.5	372.0	(124.3)	247.7
Contract-based intangibles	565.3	(304.3)	261.0	565.3	(285.8)	279.5
Segment total	1,728.9	(442.4)	1,286.5	937.3	(410.1)	527.2
Onshore Crude Oil Pipelines & Services:						
Contract-based intangibles	10.0	(3.7)	6.3	10.0	(3.5)	6.5
Segment total	10.0	(3.7)	6.3	10.0	(3.5)	6.5
Offshore Pipelines & Services:						
Customer relationship intangibles	205.8	(111.9)	93.9	205.8	(105.3)	100.5
Contract-based intangibles	1.2	(0.2)	1.0	1.2	(0.2)	1.0
Segment total	207.0	(112.1)	94.9	207.0	(105.5)	101.5
Petrochemical & Refined Products Services:						
Customer relationship intangibles	104.6	(21.3)	83.3	104.6	(18.8)	85.8
Contract-based intangibles	42.1	(16.6)	25.5	42.1	(13.9)	28.2
Segment total	146.7	(37.9)	108.8	146.7	(32.7)	114.0
Total all segments	$ 2,754.8	$ (858.7)	$ 1,896.1	$ 1,859.8	$ (795.0)	$ 1,064.8

(1) In May 2010, we acquired $895.0 million of customer relationship intangible assets in connection with the State Line and Fairplay natural gas gathering systems. See Note 8 for additional information regarding this business combination.

The following table presents amortization expense related to our intangible assets for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2010	2009	2010	2009
NGL Pipelines & Services	$ 10.1	$ 8.4	$ 19.4	$ 18.2
Onshore Natural Gas Pipelines & Services	18.1	14.9	32.3	29.5
Onshore Crude Oil Pipelines & Services	0.1	0.1	0.2	0.2
Offshore Pipelines & Services	3.2	3.7	6.6	7.6
Petrochemical & Refined Products Services	2.6	2.6	5.2	5.3
Total	$ 34.1	$ 29.7	$ 63.7	$ 60.8

The following table presents our forecast of amortization expense associated with existing intangible assets for the years presented:

Remainder of 2010	2011	2012	2013	2014
$ 72.3	$ 143.8	$ 135.3	$ 134.9	$ 136.6

In general, our intangible assets fall within two categories: customer relationships and contract-based intangible assets. The values assigned to such intangible assets are amortized to earnings using either (i) a straight-line approach or (ii) other methods that closely resemble the pattern in which the economic benefits of associated resource bases are estimated to be consumed or otherwise used.

<u>*Customer relationship intangible assets*</u>. Customer relationship intangible assets represent the estimated economic value assigned to certain relationships acquired in connection with business

combinations and asset purchases whereby (i) we acquired information about or access to customers and (ii) the customers now have the ability to make direct contact with us. Customer relationships may arise from contractual arrangements (such as supplier contracts and service contracts) and through means other than contracts, such as through regular contact by sales or service representatives. At June 30, 2010, the carrying value of our customer relationship intangible assets was $1.45 billion.

In connection with our acquisition of the State Line and Fairplay natural gas gathering systems in May 2010, we acquired $895.0 million of customer relationship intangible assets. The acquired customer relationships as of June 30, 2010 are presented in the following table:

	Gross Value	Accum. Amort.	Carrying Value
State Line natural gas gathering customer relationships (1)	$ 675.0	$ (2.8)	$ 672.2
Fairplay natural gas gathering customer relationships (1)	116.6	(1.1)	115.5
Fairplay natural gas processing customer relationships (2)	103.4	(1.0)	102.4
Total acquired customer relationships	$ 895.0	$ (4.9)	$ 890.1

(1) These natural gas gathering customer relationship intangible assets are a component of our Onshore Natural Gas Pipelines & Services business segment.
(2) The Fairplay natural gas processing customer relationship intangible assets are a component of our NGL Pipelines & Services business segment.

In this context, a customer relationship is broadly defined as a relationship between the natural gas gathering system and the production fields from which it gathers natural gas. Natural gas gathering systems require a significant investment, both in terms of initial construction costs and ongoing maintenance. Investing the capital to construct a natural gas gathering system establishes access to producers in a particular field and represents a significant economic barrier effectively limiting competition (i.e. akin to a franchise). The low risk of competition ensures a long commercial relationship with existing customers as well as a high probability of commercial relationships with new producers in the field. As such, the relationship with producers is generally limited by the quantity and production life of the underlying natural gas resource base.

The economic value we attribute to customer relationships acquired with the State Line and Fairplay systems was estimated using recognized business valuation techniques based on several key assumptions, which include assumptions regarding the renewal of existing contracts and natural gas resource bases. In general, natural gas is gathered on the State Line and Fairplay systems under long-term contracts, which include acreage dedications of approximately 110,000 acres and 100,000 acres, respectively, as well as volumetric commitments from certain natural gas producers on both systems. In addition, certain contracts related to the Fairplay system include natural gas processing services. Based on our experience as a provider of natural gas gathering and processing services, we anticipate the acquired customer relationships to extend well beyond the discrete term of existing contracts.

Customer relationship intangibles related to the State Line system have an estimated economic useful life of 27 years. The natural gas gathering and processing customer relationships associated with the Fairplay system have an estimated economic useful life of 23 years. Amortization expense is recorded using the units of production method based on gathering volumes. This method of amortization allows for expense to be recorded in a manner that closely resembles the pattern in which we benefit from natural gas gathering and processing services provided to customers. See Note 8 for additional information regarding this business combination.

Effective January 1, 2010, upon review of the future prospects for our Val Verde customer relationship intangible assets, management adjusted the amortization period to end in 2021. This change in estimate did not result in a material decrease in net income or earnings per unit for the three and six months ended June 30, 2010.

Contract-based intangible assets. Contract-based intangible assets represent specific commercial rights we acquired in connection with business combinations or asset purchases. At June 30, 2010, the carrying value of our contract-based intangible assets was $448.5 million.

Goodwill

Goodwill represents the excess of the purchase price of an acquired business over the amounts assigned to assets acquired and liabilities assumed in the transaction. Goodwill is not amortized; however, it is subject to annual impairment testing at the end of each fiscal year. The following table presents changes in the carrying amount of goodwill for the periods presented:

	NGL Pipelines & Services	Onshore Natural Gas Pipelines & Services	Onshore Crude Oil Pipelines & Services	Offshore Pipelines & Services	Petrochemical & Refined Products Services	Consolidated Totals
Balance at December 31, 2009 (1)	$ 341.2	$ 284.9	$ 303.0	$ 82.1	$ 1,007.1	$ 2,018.3
Goodwill related to acquisitions	--	26.2	6.1	--	--	32.3
Balance at June 30, 2010 (1)	$ 341.2	$ 311.1	$ 309.1	$ 82.1	$ 1,007.1	$ 2,050.6

(1) The total carrying amount of goodwill at June 30, 2010 and December 31, 2009 is reflected net of $1.3 million of accumulated impairment charges included in our Petrochemical & Refined Products Services business segment.

In May 2010, we acquired $26.2 million of goodwill in connection with our acquisition of the State Line and Fairplay natural gas gathering systems. In June 2010, we acquired an additional $6.1 million of goodwill related to our acquisition of a marine transportation business that provides crude oil gathering services in South Louisiana. We generally attribute this goodwill to our ability to leverage the acquired businesses with our existing asset base to create future business opportunities.

Goodwill impairment testing involves determining the fair value of the associated reporting unit. These fair value amounts are based on assumptions regarding the future economic prospects of the businesses that make up the reporting unit. Such assumptions include (i) discrete financial forecasts for the businesses contained within the reporting unit, which rely on management’s estimates of operating margins, throughput volumes and similar factors; (ii) long-term growth rates for cash flows beyond the discrete forecast period; and (iii) appropriate discount rates. Based on our most recent goodwill impairment tests, each reporting unit’s fair value was substantially in excess of its carrying value (i.e., by at least 10%).

Note 10. Debt Obligations

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

	June 30, 2010	December 31, 2009
EPO senior debt obligations:		
Multi-Year Revolving Credit Facility, variable-rate, due November 2012	$ --	$ 195.5
Pascagoula MBFC Loan, 8.70% fixed-rate, due March 2010	--	54.0
Petal GO Zone Bonds, variable-rate, due August 2034	57.5	57.5
Senior Notes B, 7.50% fixed-rate, due February 2011 (1)	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 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, 4.95% fixed-rate, due June 2010	--	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	500.0
Senior Notes Q, 5.25% fixed-rate, due January 2020	500.0	500.0
Senior Notes R, 6.125% fixed-rate, due October 2039	600.0	600.0
Senior Notes S, 7.625% fixed-rate, due February 2012	490.5	490.5
Senior Notes T, 6.125% fixed-rate, due February 2013	182.5	182.5
Senior Notes U, 5.90% fixed-rate, due April 2013	237.6	237.6
Senior Notes V, 6.65% fixed-rate, due April 2018	349.7	349.7
Senior Notes W, 7.55% fixed-rate, due April 2038	399.6	399.6
Senior Notes X, 3.70% fixed-rate, due June 2015	400.0	--
Senior Notes Y, 5.20% fixed-rate, due September 2020	1,000.0	--
Senior Notes Z, 6.45% fixed-rate, due September 2040	600.0	--
TEPPCO senior debt obligations:		
TEPPCO Senior Notes	40.1	40.1
Duncan Energy Partners' debt obligations:		
DEP Revolving Credit Facility, variable-rate, due February 2011 (2)	255.0	175.0
DEP Term Loan, variable-rate, due December 2011	282.3	282.3
Total principal amount of senior debt obligations	11,094.8	9,764.3
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
EPO Junior Subordinated Notes C, fixed/variable-rate, due June 2067	285.8	285.8
TEPPCO Junior Subordinated Notes, fixed/variable-rate, due June 2067	14.2	14.2
Total principal amount of senior and junior debt obligations	12,627.5	11,297.0
Other, non-principal amounts:		
Change in fair value of debt-related derivative instruments (see Note 4)	51.5	44.4
Unamortized discounts, net of premiums	(24.8)	(18.7)
Unamortized deferred net gains related to terminated interest rate swaps (see Note 4)	17.3	23.7
Total other, non-principal amounts	44.0	49.4
Less current maturities of debt (2)	(255.0)	--
Total long-term debt	$ 12,416.5	$ 11,346.4

(1) Long-term and current maturities of debt reflect the classification of such obligations at June 30, 2010 after taking into consideration EPO's ability to use available long-term borrowing capacity under its Multi-Year Revolving Credit Facility to satisfy the current maturities of Senior Notes B.
(2) Reflects Duncan Energy Partners' classification of debt at June 30, 2010.

Letters of Credit

At June 30, 2010, EPO had a $50.0 million letter of credit outstanding related to its commodity derivative instruments and a $58.3 million letter of credit outstanding related to its Petal GO Zone Bonds.

These letter of credit facilities do not reduce the amount available for borrowing under EPO's Multi-Year Revolving Credit Facility.

Parent-Subsidiary Guarantor Relationships

Enterprise Products Partners acts as guarantor of the consolidated debt obligations of EPO with the exception of the DEP Revolving Credit Facility, the DEP Term Loan and the remaining debt obligations of TEPPCO. 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.

The borrowings of Duncan Energy Partners are presented as part of our consolidated debt balances. However, neither Enterprise Products Partners nor EPO have any obligation for the payment of interest or repayment of borrowings incurred by Duncan Energy Partners.

Debt Obligations

Apart from that discussed below and routine fluctuations in the balance of our consolidated revolving credit facilities, there have been no significant changes in the terms of our consolidated debt obligations since those reported in our 2009 Form 10-K.

Pascagoula MBFC Loan. This loan, from the Mississippi Business Finance Corporation ("MBFC"), matured in March 2010 and was repaid.

Senior Notes X, Y and Z. On May 20, 2010, EPO issued an aggregate of $2.0 billion in principal amount of senior unsecured notes. EPO issued (i) $400.0 million in principal amount of 5-year senior unsecured notes ("Senior Notes X") at 99.79% of their principal amount, (ii) $1.0 billion in principal amount of 10-year senior unsecured notes ("Senior Notes Y") at 99.701% of their principal amount and (iii) $600.0 million in principal amount of 30-year senior unsecured notes ("Senior Notes Z") at 99.525% of their principal amount. Net proceeds from the issuance of these senior notes were used (i) to repay EPO's Senior Notes K in June 2010, (ii) to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and (iii) for general partnership purposes. On May 4, 2010, EPO borrowed $850.0 million under its Multi-Year Revolving Credit Facility to fund a portion of the cash consideration paid to complete the State Line and Fairplay acquisitions (see Note 8).

Senior Notes X, Y and Z rank equal with EPO's existing and future unsecured and unsubordinated indebtedness. They are senior to any existing and future subordinated indebtedness of EPO. They are also 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.

Covenants

We were in compliance with the financial covenants of our consolidated debt agreements at June 30, 2010.

Information Regarding Variable Interest Rates Paid

The following table shows the range of interest rates and weighted-average interest rate paid on our consolidated variable-rate debt obligations during the six months ended June 30, 2010:

	Range of Interest Rates Paid	**Weighted-Average Interest Rate Paid**
EPO Multi-Year Revolving Credit Facility	0.73% to 3.25%	0.85%
DEP Revolving Credit Facility	0.80% to 1.11%	0.85%
DEP Term Loan	0.93% to 1.05%	0.97%
Petal GO Zone Bonds	0.12% to 0.30%	0.23%

Consolidated Debt Maturity Table

The following table presents contractually scheduled maturities of our consolidated debt obligations for the next five years, and in total thereafter:

		Scheduled Maturities of Debt				
	Total	**2011**	**2012**	**2013**	**2014**	**After 2014**
Revolving Credit Facilities	$ 255.0	$ 255.0	$ --	$ --	$ --	$ --
Senior Notes	10,500.0	450.0	1,000.0	1,200.0	1,150.0	6,700.0
Term Loans	282.3	282.3	--	--	--	--
Junior Subordinated Notes	1,532.7	--	--	--	--	1,532.7
Other	57.5	--	--	--	--	57.5
Total	$ 12,627.5	$ 987.3	$ 1,000.0	$ 1,200.0	$ 1,150.0	$ 8,290.2

Long-term and current maturities of debt reflect the classification of such obligations at June 30, 2010 after taking into consideration EPO's ability to use available long-term borrowing capacity under its Multi-Year Revolving Credit Facility to satisfy the current maturities of Senior Notes B ($450.0 million due in February 2011).

Debt Obligations of Unconsolidated Affiliates

We have three unconsolidated affiliates with long-term debt obligations. The following table shows (i) our ownership interest in each entity at June 30, 2010, (ii) the total debt of each unconsolidated affiliate at June 30, 2010 (on a 100% basis to the unconsolidated affiliate) and (iii) the corresponding scheduled maturities of such debt.

			Scheduled Maturities of Debt					
	Ownership Interest	**Total**	**Remainder of 2010**	**2011**	**2012**	**2013**	**2014**	**After 2014**
Poseidon	36%	$ 92.0	$ --	$ 92.0	$ --	$ --	$ --	$ --
Evangeline	49.5%	10.7	3.2	7.5	--	--	--	--
Centennial	50%	115.4	4.5	9.0	8.9	8.6	8.6	75.8
Total		$ 218.1	$ 7.7	$ 108.5	$ 8.9	$ 8.6	$ 8.6	$ 75.8

The credit agreements of these unconsolidated affiliates include customary covenants, including financial covenants. These businesses were in compliance with such financial covenants at June 30, 2010. The credit agreements of these unconsolidated affiliates restrict their ability to pay cash dividends or distributions if a default or an event of default (as defined in each credit agreement) has occurred and is continuing at the time such dividend or distribution 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 2009 Form 10-K.

Note 11. Equity and Distributions

Our common units represent limited partner interests, which give 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.

In accordance with the Partnership Agreement, capital accounts are maintained for our general partner and limited partners. The capital account provisions of the Partnership Agreement incorporate principles established for U.S. federal income tax purposes and are not comparable to the GAAP-based equity amounts presented in our consolidated financial statements. Earnings and cash distributions are allocated to holders of our common units in accordance with their respective ownership interests.

Registration Statements and Equity Offerings

We have filed registration statements with the SEC authorizing the issuance of up to an aggregate of 70,000,000 common units in connection with our distribution reinvestment plan ("DRIP"). The DRIP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of common units they own by reinvesting the quarterly cash distributions they would otherwise receive into the purchase of additional common units. A total of 38,149,089 common units have been issued under the DRIP through June 30, 2010.

In addition to the DRIP, we have filed a registration statement with the SEC authorizing the issuance of up to an aggregate of 1,200,000 common units in connection with our employee unit purchase plan ("EUPP"). Under this plan, employees of EPCO can purchase our common units at a 10% discount through payroll deductions. A total of 937,429 common units have been issued to employees under this plan through June 30, 2010.

In July 2010, we filed a new universal shelf registration statement with the SEC that allows us to issue an unlimited amount of debt and equity securities. No securities have been issued under this registration statement as of the filing date of this quarterly report. Under our prior universal shelf registration statement we issued 43,652,500 common units, which generated $1.27 billion of net cash proceeds, and $5.2 billion of senior notes through June 30, 2010.

The following table reflects the number of common units issued and the net cash proceeds received from underwritten offerings and the DRIP and EUPP during the six months ended June 30, 2010:

	Net Cash Proceeds from Issuance of Common Units			
	Number of Common Units Issued	Contributed by Limited Partners	Contributed by General Partner	Total Net Cash Proceeds
January underwritten offering	10,925,000	$ 343.3	$ 7.0	$ 350.3
February DRIP and EUPP	2,834,584	85.0	1.8	86.8
April underwritten offering	13,800,000	474.9	9.7	484.6
May DRIP and EUPP	2,039,670	67.1	1.3	68.4
Total 2010	29,599,254	$ 970.3	$ 19.8	$ 990.1

In January 2010, we issued 10,925,000 common units (including an over-allotment of 1,425,000 common units) to the public at an offering price of $32.42 per unit. We used the total net cash proceeds of $350.3 million to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes.

In April 2010, we issued 13,800,000 common units (including an over-allotment of 1,800,000 common units) to the public at an offering price of $35.55 per unit. We used the total net cash proceeds of $484.6 million to fund a portion of the cash consideration paid to acquire the State Line and Fairplay systems in May 2010 (see Note 8) and for general partnership purposes.

Net cash proceeds received in 2010 from our DRIP and EUPP were used to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes.

Class B Units

In October 2009, in connection with the TEPPCO Merger, a privately held affiliate of EPCO exchanged a portion of its TEPPCO units, based on the 1.24 exchange rate, for 4,520,431 of our Class B units in lieu of common units. The Class B units are not entitled to receive regular quarterly cash distributions for the first sixteen quarters following the closing date of the merger. The Class B units automatically convert into the same number of common units on the date immediately following the payment date for the sixteenth regular quarterly distribution following the closing date of the merger. The

Class B units are entitled to vote together with the common units as a single class on partnership matters and, except for the payment of distributions, have the same rights and privileges as our common units.

Summary of Changes in Outstanding Units

The following table summarizes changes in the number of our limited partner units outstanding since December 31, 2009:

	Common Units	Restricted Common Units	Class B Units	Treasury Units
Balance, December 31, 2009	603,202,828	2,720,882	4,520,431	--
Common units issued in connection with underwritten offerings	24,725,000	--	--	--
Common units issued in connection with DRIP and EUPP	4,874,254	--	--	--
Common units issued in connection with equity awards	45,872	--	--	--
Restricted units issued	--	1,332,875	--	--
Forfeiture of restricted units	--	(93,148)	--	--
Conversion of restricted units to common units	322,228	(322,228)	--	--
Acquisition of treasury units	(86,002)	--	--	86,002
Cancellation of treasury units	--	--	--	(86,002)
Other	(61)	--	--	--
Balance, June 30, 2010	633,084,119	3,638,381	4,520,431	--

Summary of Changes in Limited Partners' Equity

The following table details changes in limited partners' equity since December 31, 2009:

	Common Units	Restricted Common Units	Class B Units	Total
Balance, December 31, 2009	$ 9,173.5	$ 37.7	$ 118.5	$ 9,329.7
Net income	608.3	3.4	--	611.7
Operating lease expenses paid by EPCO	0.3	--	--	0.3
Cash distributions paid to partners	(701.9)	(3.8)	--	(705.7)
Unit option-related reimbursements to EPCO	(2.2)	--	--	(2.2)
Net cash proceeds from issuance of common units	970.3	--	--	970.3
Cash proceeds from exercise of unit options	1.6	--	--	1.6
Amortization of equity awards	3.1	14.8	--	17.9
Acquisition of treasury units	--	(3.0)	--	(3.0)
Other	--	0.2	--	0.2
Balance, June 30, 2010	$ 10,053.0	$ 49.3	$ 118.5	$ 10,220.8

Distributions to Partners

The following table presents our declared quarterly cash distribution rates per common unit since the first quarter of 2009 and the related record and distribution payment dates. The quarterly cash distribution rates per common unit correspond to the fiscal quarters indicated. Actual cash distributions are paid within 45 days after the end of such fiscal quarter.

	Distribution Per Common Unit	Record Date	Payment Date
2009			
1st Quarter	$0.5375	Apr. 30, 2009	May 8, 2009
2nd Quarter	$0.5450	Jul. 31, 2009	Aug. 7, 2009
3rd Quarter	$0.5525	Oct. 30, 2009	Nov. 5, 2009
4th Quarter	$0.5600	Jan. 29, 2010	Feb. 4, 2010
2010			
1st Quarter	$0.5675	Apr. 30, 2010	May 6, 2010
2nd Quarter	$0.5750	Jul. 30, 2010	Aug. 5, 2010

The following table presents our total cash distributions paid to partners for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2010	2009	2010	2009
Standard distributions to EPGP	$ 7.4	$ 5.0	$ 14.4	$ 9.9
Incentive distributions to EPGP	56.9	36.6	110.8	71.8
Limited partner distributions	360.2	244.9	705.7	484.4
Cash distributions paid to partners	$ 424.5	$ 286.5	$ 830.9	$ 566.1

Accumulated Other Comprehensive Income (Loss)

Our accumulated other comprehensive income (loss) amounts primarily include the effective portion of the gain or loss on derivative instruments designated and qualified as cash flow hedges. Amounts accumulated in other comprehensive income (loss) related to cash flow hedges are reclassified into earnings in the same period(s) in which the underlying hedged forecasted transactions affect earnings. If it becomes probable that a forecasted transaction will not occur, the net gain or loss in accumulated other comprehensive income (loss) must be immediately reclassified.

The following table presents the components of accumulated other comprehensive income (loss) as reported on our Unaudited Condensed Consolidated Balance Sheets at the dates indicated:

	June 30, 2010	December 31, 2009
Commodity derivative instruments (1)	$ 48.6	$ 0.5
Interest rate derivative instruments (1)	(82.4)	(12.5)
Foreign currency derivative instruments (1)	(0.1)	0.4
Foreign currency translation adjustment (2)	0.6	0.8
Pension and postretirement benefit plans	(1.7)	(0.8)
Subtotal	(35.0)	(11.6)
Amounts attributable to noncontrolling interests	1.8	3.2
Total accumulated other comprehensive loss in partners' equity	$ (33.2)	$ (8.4)

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

Noncontrolling Interests

Prior to the completion of the TEPPCO Merger, we accounted for the economic interest of the former owners of TEPPCO and TEPPCO GP as noncontrolling interests. Under this method of presentation, all pre-merger revenues and expenses of TEPPCO and TEPPCO GP are included in net income, and the former owners' share of the income of TEPPCO and TEPPCO GP is allocated to net income attributable to 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, 2010	December 31, 2009
Limited partners of Duncan Energy Partners:		
Third-party owners of Duncan Energy Partners (1)	$ 412.2	$ 414.3
Related party owners of Duncan Energy Partners	1.7	1.7
Joint venture partners (2)	116.9	117.4
Accumulated other comprehensive loss attributable to noncontrolling interests	(1.8)	(3.2)
Total	$ 529.0	$ 530.2

(1) Represents non-affiliate public unitholders of Duncan Energy Partners.
(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, Rio Grande Pipeline, LLC and Wilprise Pipeline Company LLC.

The following table presents the components of net income attributable to noncontrolling interests 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,	
	2010	2009	2010	2009
Former owners of TEPPCO	$ --	$ 12.3	$ --	$ 90.6
Limited partners of Duncan Energy Partners	9.6	6.6	18.3	11.7
Joint venture partners	6.5	7.0	13.8	13.8
Total	$ 16.1	$ 25.9	$ 32.1	$ 116.1

The following table presents cash distributions paid to and cash contributions received from noncontrolling interests 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,	
	2010	2009
Cash distributions paid to noncontrolling interests:		
Limited partners of TEPPCO	$ --	$ 182.8
Limited partners of Duncan Energy Partners	21.3	12.8
Joint venture partners	15.3	15.0
Total cash distributions paid to noncontrolling interests	$ 36.6	$ 210.6
Cash contributions from noncontrolling interests:		
Limited partners of TEPPCO	$ --	$ 3.3
Limited partners of Duncan Energy Partners	0.8	123.2
Joint venture partners	1.1	(2.2)
Total cash contributions from noncontrolling interests	$ 1.9	$ 124.3

Cash distributions paid to the limited partners of Duncan Energy Partners and TEPPCO (prior to the completion of the TEPPCO Merger on October 26, 2009) represent the quarterly cash distributions paid by these entities to their unitholders. Cash contributions received from the limited partners of Duncan Energy Partners and TEPPCO (prior to the completion of the TEPPCO Merger) represent proceeds each entity received from the issuance of limited partner units. In June 2009, Duncan Energy Partners issued 8,000,000 of its common units, which generated net cash proceeds of approximately $123.2 million. Duncan Energy Partners used the net proceeds from its June 2009 offering to repurchase and cancel an equal number of its common units beneficially owned by EPO.

Note 12. Business Segments

We have five reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services and (v) Petrochemical & Refined Products 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 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 our 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 an alternative to GAAP operating income.

We define total segment gross operating margin as operating income before: (i) depreciation, amortization and accretion expenses; (ii) non-cash asset impairment charges; (iii) operating lease expenses for which we do not have the payment obligation (e.g., the EPCO retained leases); (iv) gains and losses from asset sales and related transactions; and (v) general and administrative costs. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intercompany transactions. In accordance with GAAP, intercompany accounts and transactions are eliminated in the preparation of our consolidated financial statements. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, the cumulative effect of changes in accounting principles and extraordinary charges. Gross operating margin is presented on a 100% basis before the allocation of earnings to noncontrolling interests.

We consolidate the financial statements of Duncan Energy Partners with those of our own. As a result, our consolidated gross operating margin amounts include the gross operating margin amounts of Duncan Energy Partners.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2010	2009	2010	2009
Revenues	$ 7,543.4	$ 5,434.3	$ 16,087.9	$ 10,321.2
Less: Operating costs and expenses	(6,974.2)	(5,024.5)	(14,946.1)	(9,401.1)
Add: Equity in income of unconsolidated affiliates	16.7	9.6	32.7	17.0
Depreciation, amortization and accretion in operating costs and expenses (1)	227.0	200.5	439.4	396.9
Non-cash asset impairment charges	--	2.3	1.5	2.3
Operating lease expenses paid by EPCO	0.1	0.1	0.3	0.3
Losses (gains) from asset sales and related transactions in operating costs and expenses (2)	1.7	(0.2)	(5.6)	(0.4)
Total segment gross operating margin	$ 814.7	$ 622.1	$ 1,610.1	$ 1,336.2

(1) Amount is a component of "Depreciation, amortization and accretion" as presented on our Unaudited Condensed Statements of Consolidated Cash Flows.
(2) Amount is a component of "Gains from asset sales and related transactions" as presented on our Unaudited Condensed Statements of Consolidated Cash Flows.

The following table presents a reconciliation of our non-GAAP total segment gross operating margin to GAAP operating income and income before provision for income taxes for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2010	2009	2010	2009
Total segment gross operating margin	$ 814.7	$ 622.1	$ 1,610.1	$ 1,336.2
Adjustments to reconcile total segment gross operating margin to operating income:				
Depreciation, amortization and accretion in operating costs and expenses	(227.0)	(200.5)	(439.4)	(396.9)
Non-cash asset impairment charges	--	(2.3)	(1.5)	(2.3)
Operating lease expenses paid by EPCO	(0.1)	(0.1)	(0.3)	(0.3)
Gains (losses) from asset sales and related transactions in operating costs and expenses	(1.7)	0.2	5.6	0.4
General and administrative costs	(37.9)	(46.1)	(75.5)	(81.0)
Operating income	548.0	373.3	1,099.0	856.1
Other expense, net	(168.2)	(157.7)	(316.7)	(309.0)
Income before provision for income taxes	$ 379.8	$ 215.6	$ 782.3	$ 547.1

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	Onshore Crude Oil Pipelines & Services	Offshore Pipelines & Services	Petrochemical & Refined Products Services	Adjustments And Eliminations	Consolidated Totals
Revenues from third parties:							
Three months ended June 30, 2010	$ 2,923.8	$ 786.2	$ 2,629.3	$ 85.5	$ 1,002.6	$ --	$ 7,427.4
Three months ended June 30, 2009	2,359.0	631.8	1,726.4	77.3	547.5	--	5,342.0
Six months ended June 30, 2010	6,590.1	1,897.3	5,016.0	172.0	2,064.1	--	15,739.5
Six months ended June 30, 2009	4,625.9	1,299.5	2,996.1	145.8	942.1	--	10,009.4
Revenues from related parties:							
Three months ended June 30, 2010	55.5	58.7	--	1.8	--	--	116.0
Three months ended June 30, 2009	44.6	47.1	0.6	--	--	--	92.3
Six months ended June 30, 2010	235.5	109.1	(0.1)	3.9	--	--	348.4
Six months ended June 30, 2009	198.1	112.9	0.8	--	--	--	311.8
Intersegment and intrasegment revenues:							
Three months ended June 30, 2010	2,407.7	212.7	223.4	0.3	287.2	(3,131.3)	--
Three months ended June 30, 2009	1,507.1	113.6	15.4	0.3	119.0	(1,755.4)	--
Six months ended June 30, 2010	4,954.9	428.3	248.1	0.7	545.0	(6,177.0)	--
Six months ended June 30, 2009	2,895.0	267.3	23.6	0.6	235.2	(3,421.7)	--
Total revenues:							
Three months ended June 30, 2010	5,387.0	1,057.6	2,852.7	87.6	1,289.8	(3,131.3)	7,543.4
Three months ended June 30, 2009	3,910.7	792.5	1,742.4	77.6	666.5	(1,755.4)	5,434.3
Six months ended June 30, 2010	11,780.5	2,434.7	5,264.0	176.6	2,609.1	(6,177.0)	16,087.9
Six months ended June 30, 2009	7,719.0	1,679.7	3,020.5	146.4	1,177.3	(3,421.7)	10,321.2
Equity in income (loss) of unconsolidated affiliates:							
Three months ended June 30, 2010	3.7	0.9	3.6	11.1	(2.6)	--	16.7
Three months ended June 30, 2009	2.3	1.4	2.9	6.8	(3.8)	--	9.6
Six months ended June 30, 2010	7.0	2.2	5.9	22.9	(5.3)	--	32.7
Six months ended June 30, 2009	3.5	2.5	6.2	11.5	(6.7)	--	17.0
Gross operating margin:							
Three months ended June 30, 2010	441.0	106.9	25.9	82.8	158.1	--	814.7
Three months ended June 30, 2009	363.8	121.2	42.1	(1.1)	96.1	--	622.1
Six months ended June 30, 2010	878.3	237.2	52.6	163.9	278.1	--	1,610.1
Six months ended June 30, 2009	714.7	283.1	92.6	60.2	185.6	--	1,336.2
Segment assets:							
At June 30, 2010	7,372.2	7,988.3	904.0	2,068.8	3,585.5	1,233.1	23,151.9
At December 31, 2009	7,191.2	6,918.7	865.4	2,121.4	3,359.0	1,207.2	21,662.9
Property, plant and equipment: (see Note 6)							
At June 30, 2010	6,492.8	6,358.3	412.7	1,442.6	2,392.5	1,233.1	18,332.0
At December 31, 2009	6,392.8	6,074.6	377.4	1,480.9	2,156.3	1,207.2	17,689.2
Investments in unconsolidated affiliates: (see Note 7)							
At June 30, 2010	138.6	32.4	175.9	449.2	77.1	--	873.2
At December 31, 2009	141.6	32.0	178.5	456.9	81.6	--	890.6
Intangible assets, net: (see Note 9)							
At June 30, 2010	399.6	1,286.5	6.3	94.9	108.8	--	1,896.1
At December 31, 2009	315.6	527.2	6.5	101.5	114.0	--	1,064.8
Goodwill: (see Note 9)							
At June 30, 2010	341.2	311.1	309.1	82.1	1,007.1	--	2,050.6
At December 31, 2009	341.2	284.9	303.0	82.1	1,007.1	--	2,018.3

Property, plant and equipment, intangible assets and goodwill for the Onshore Natural Gas Pipelines & Services business segment and intangible assets for the NGL Pipelines & Services business segment increased in May 2010 as a result of completing the State Line and Fairplay acquisitions (see Note 8).

The following table provides additional information regarding our consolidated revenues and costs and expenses for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2010	2009	2010	2009
NGL Pipelines & Services:				
Sales of NGLs	$ 2,804.4	$ 2,260.0	$ 6,468.5	$ 4,512.2
Sales of other petroleum and related products	0.7	0.4	1.2	0.9
Midstream services	174.2	143.2	355.9	310.9
Total	2,979.3	2,403.6	6,825.6	4,824.0
Onshore Natural Gas Pipelines & Services:				
Sales of natural gas	655.6	497.4	1,630.8	1,054.0
Midstream services	189.3	181.5	375.6	358.4
Total	844.9	678.9	2,006.4	1,412.4
Onshore Crude Oil Pipelines & Services:				
Sales of crude oil	2,603.4	1,709.0	4,970.7	2,954.8
Midstream services	25.9	18.0	45.2	42.1
Total	2,629.3	1,727.0	5,015.9	2,996.9
Offshore Pipelines & Services:				
Sales of natural gas	0.4	0.3	0.8	0.6
Sales of crude oil	1.9	0.9	4.0	1.1
Midstream services	85.0	76.1	171.1	144.1
Total	87.3	77.3	175.9	145.8
Petrochemical & Refined Products Services:				
Sales of other petroleum and related products	871.7	413.3	1,804.3	674.8
Midstream services	130.9	134.2	259.8	267.3
Total	1,002.6	547.5	2,064.1	942.1
Total consolidated revenues	$ 7,543.4	$ 5,434.3	$ 16,087.9	$ 10,321.2
Consolidated cost and expenses:				
Operating costs and expenses:				
Cost of sales related to our marketing activities	$ 5,693.5	$ 3,872.6	$ 12,342.7	$ 7,275.9
Depreciation, amortization and accretion	227.0	200.5	439.4	396.9
Losses (gains) from asset sales and related transactions	1.7	(0.2)	(5.6)	(0.4)
Non-cash asset impairment charges	--	2.3	1.5	2.3
Other operating costs and expenses	1,052.0	949.3	2,168.1	1,726.4
General and administrative costs	37.9	46.1	75.5	81.0
Total consolidated costs and expenses	$ 7,012.1	$ 5,070.6	$ 15,021.6	$ 9,482.1

The following table reconciles our recast consolidated revenues and total segment gross operating margin to our pre-merger reported amounts for the periods indicated:

	For the Three Months Ended June 30, 2009	For the Six Months Ended June 30, 2009
Total revenues, as previously reported	$ 3,507.9	$ 6,931.0
Revenues from TEPPCO	1,913.3	3,370.8
Revenues from Jonah Gas Gathering Company ("Jonah") (1)	61.2	120.6
Eliminations (2)	(48.1)	(101.2)
Total revenues, as recast and currently reported	$ 5,434.3	$ 10,321.2
Total segment gross operating margin, as previously reported	$ 509.2	$ 1,057.9
Gross operating margin from TEPPCO	98.9	253.0
Gross operating margin from Jonah	43.5	86.6
Eliminations (3)	(29.5)	(61.3)
Total segment gross operating margin, as recast and currently reported	$ 622.1	$ 1,336.2

(1) Prior to the TEPPCO Merger, we and TEPPCO were joint venture partners in Jonah. As a result of the TEPPCO Merger, Jonah became a consolidated subsidiary of ours.
(2) Represents the elimination of revenues between Enterprise Products Partners, TEPPCO and Jonah as appropriate in consolidation.
(3) Represents the elimination of equity earnings from Jonah recorded by Enterprise Products Partners and TEPPCO as appropriate in consolidation.

Note 13. Related Party Transactions

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2010	2009	2010	2009
Revenues – related parties:				
Energy Transfer Equity and subsidiaries	$ 59.9	$ 49.2	$ 246.5	$ 212.0
Unconsolidated affiliates	56.1	43.1	101.9	99.8
Total revenue – related parties	$ 116.0	$ 92.3	$ 348.4	$ 311.8
Costs and expenses – related parties:				
EPCO and affiliates	$ 164.7	$ 151.4	$ 323.1	$ 295.2
Energy Transfer Equity and subsidiaries	147.2	105.6	324.1	197.0
Unconsolidated affiliates	9.5	6.8	21.7	13.7
Other	--	14.2	--	28.6
Total costs and expenses – related parties	$ 321.4	$ 278.0	$ 668.9	$ 534.5

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

	June 30, 2010	December 31, 2009
Accounts receivable - related parties:		
Energy Transfer Equity and subsidiaries	$ 6.6	$ 28.2
Other	23.2	10.2
Total accounts receivable – related parties	$ 29.8	$ 38.4
Accounts payable - related parties:		
EPCO and affiliates	$ 83.4	$ 26.8
Energy Transfer Equity and subsidiaries	45.2	33.4
Other	8.3	9.6
Total accounts payable – related parties	$ 136.9	$ 69.8

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.

Relationship 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 sole general partner;
- Enterprise GP Holdings, which owns and controls our general partner; and
- the Employee Partnerships (see Note 3).

EPCO is a privately held company controlled collectively by the EPCO Trustees. At June 30, 2010, EPCO and its affiliates (including Dan Duncan LLC and two Duncan family trusts the beneficiaries of which include the estate of Mr. Duncan) beneficially owned interests in the following entities:

	Number of Units	Percentage of Outstanding Units
Enterprise Products Partners L.P. (1,(2)	197,201,947	30.8%
Enterprise GP Holdings L.P. (3)	108,919,199	78.2%

(1) Includes 4,520,431 Class B units owned by a privately held affiliate of EPCO and 21,563,177 common units owned by Enterprise GP Holdings.
(2) Enterprise GP Holdings owns 100% of our general partner, EPGP.
(3) Dan Duncan LLC owns 100% of the member interests of EPE Holdings, which is the general partner of Enterprise GP Holdings.

The principal business activity of EPGP is to act as our sole managing partner. The executive officers and certain of the directors of EPGP are employees of EPCO. The following table presents cash distributions paid by us to EPGP for the periods indicated:

	For the Six Months Ended June 30, 2010	2009
General partner distributions	$ 14.4	$ 9.9
Incentive distributions	110.8	71.8
Total distributions	$ 125.2	$ 81.7

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 affiliates 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. The following table presents cash distributions received by EPCO and its privately held affiliates from us and Enterprise GP Holdings for the periods indicated:

	For the Six Months Ended June 30, 2010	2009
Enterprise Products Partners	$ 168.0	$ 152.4
Enterprise GP Holdings	116.1	95.6
Total distributions	$ 284.1	$ 248.0

Substantially all of the ownership interests in us that are owned or controlled by Enterprise GP Holdings are pledged as security under its credit facility. In addition, substantially all of the ownership interests in us that are owned or controlled by EPCO and its affiliates, other than those interests owned by Enterprise GP Holdings, Dan Duncan LLC and certain trusts of which the estate of Dan L. Duncan is a beneficiary, are pledged as security under the credit facility of a privately held affiliate of EPCO. This credit facility contains customary and other events of default relating to EPCO and certain affiliates, including Enterprise GP Holdings and us.

We have entered into an agreement with an affiliate of EPCO to provide trucking services to us for the transportation of NGLs and other products. We also lease office space in various buildings from affiliates of EPCO. The rental rates in these lease agreements approximate market rates.

EPCO ASA

We have no employees. All of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to the ASA or by other service providers. We, Duncan Energy Partners, Enterprise GP Holdings and our respective general partners are parties to the ASA. The significant terms of the ASA are as follows:

- EPCO will provide selling, general and administrative services and management and operating services as may be necessary to manage and operate our businesses, properties and assets (all in accordance with prudent industry practices). EPCO will employ or otherwise retain the services of such personnel as may be necessary to provide such services.

- We are required to reimburse EPCO for its services in an amount equal to the sum of all costs and expenses incurred by EPCO which are directly or indirectly related to our business or activities (including expenses reasonably allocated to us by EPCO). In addition, we have agreed to pay all sales, use, excise, value added or similar taxes, if any, that may be applicable from time to time with respect to the services provided to us by EPCO.

- EPCO will allow us to participate as a named insured in its overall insurance program, with the associated premiums and other costs being allocated to us. See Note 16 for additional information regarding our insurance programs.

Under the ASA, EPCO subleases to us (for $1 per year) certain equipment it holds pursuant to operating leases and has assigned to us its purchase option under such leases. EPCO remains liable for the actual cash payments associated with these lease agreements. We record the full value of these payments made by EPCO on our behalf as a non-cash related party operating lease expense, with the offset to equity accounted for as a general contribution to our partnership.

Our operating costs and expenses include amounts paid to EPCO for the costs it incurs to operate our facilities, including the compensation of employees. We reimburse EPCO for actual direct and indirect expenses it incurs related to the operation of our assets. Our general and administrative costs include amounts paid to EPCO for administrative services, including the compensation of employees. In general, our reimbursement to EPCO for administrative services is either (i) on an actual basis for direct expenses it may incur on our behalf (e.g., the purchase of office supplies) or (ii) based on an allocation of such charges between the various parties to the ASA based on the estimated use of such services by each party (e.g., the allocation of legal or accounting salaries based on estimates of time spent on each entity's business and affairs). The following table presents a breakout of costs and expenses related to the ASA and other EPCO transactions for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2010	2009	2010	2009
Operating costs and expenses	$ 140.9	$ 127.4	$ 275.3	$ 245.2
General and administrative expenses	23.8	24.0	47.8	50.0
Total costs and expenses	$ 164.7	$ 151.4	$ 323.1	$ 295.2

Since the vast majority of such expenses are charged to us on an actual basis (i.e., no mark-up or subsidy is charged or received by EPCO), we believe that such expenses are representative of what the amounts would have been on a standalone basis. With respect to allocated costs, we believe that the proportional direct allocation method employed by EPCO is reasonable and reflective of the estimated level of costs we would have incurred on a standalone basis.

The ASA also addresses potential conflicts that may arise among Enterprise Products Partners (including EPGP), Enterprise GP Holdings (including EPE Holdings), Duncan Energy Partners (including DEP GP), and the EPCO Group with respect to business opportunities (as defined within the ASA) with third parties. The EPCO Group includes EPCO and its other affiliates, but excludes Enterprise Products Partners, Enterprise GP Holdings, Duncan Energy Partners and their respective general partners.

Relationship with Energy Transfer Equity

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

We have a long-term sales contract with Titan Energy Partners, L.P. ("Titan"), which is a consolidated subsidiary of ETP. Titan purchases substantially all of its propane requirements from us. The contract, which was scheduled to expire March 31, 2010, has been extended through March 31, 2015. In addition, 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.

Relationships with Unconsolidated Affiliates

Many of our unconsolidated affiliates (see Note 7) support or complement our other midstream business operations. The following information summarizes significant related party transactions with our unconsolidated affiliates:

- We sell natural gas to Evangeline, which, in turn, uses the natural gas to satisfy supply commitments it has with a major Louisiana utility. Revenues from Evangeline were $49.0 million and $39.9 million for the three months ended June 30, 2010 and 2009, respectively. During the six months ended June 30, 2010 and 2009, revenues from Evangeline were $86.8 million and $93.5 million, respectively.

- We pay Promix for the transportation, storage and fractionation of NGLs. In addition, we sell natural gas to Promix for its plant fuel requirements. Revenues from Promix were $3.1 million and $2.4 million for the three months ended June 30, 2010 and 2009, respectively. During the six months ended June 30, 2010 and 2009, revenues from Promix were $6.2 million and $5.1 million, respectively. Expenses with Promix were $7.5 million and $6.5 million for the three months ended June 30, 2010 and 2009, respectively. During the six months ended June 30, 2010 and 2009, expenses with Promix were $16.1 million and $11.0 million, respectively.

- We paid $0.3 million and $0.7 million to Centennial for pipeline transportation services during the three months ended June 30, 2010 and 2009, respectively. During the six months ended June 30, 2010 and 2009, we paid Centennial $2.9 million and $2.4 million, respectively, for such services.

- We paid $1.6 million and $0.8 million to Seaway for pipeline transportation and tank rentals during the three months ended June 30, 2010 and 2009, respectively. During the six months ended June 30, 2010 and 2009, we paid Seaway $2.7 million and $2.6 million, respectively, for such services.

- We perform management services for certain of our unconsolidated affiliates. We charged such affiliates $2.8 million and $2.7 million for the three months ended June 30, 2010 and 2009, respectively. During the six months ended June 30, 2010 and 2009, we charged affiliates $5.7 million and $5.3 million, respectively.

Relationship with Duncan Energy Partners

We formed Duncan Energy Partners in September 2006, but it did not own or acquire any assets prior to February 5, 2007, which was the date it completed its initial public offering of common units and acquired controlling interests in five midstream energy businesses from EPO in a drop down transaction. On December 8, 2008, Duncan Energy Partners acquired controlling interests in three additional midstream energy businesses from EPO through a second drop down transaction. 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 (i) NGL transportation, fractionation and marketing; (ii) storage of NGL and petrochemical products; (iii) transportation of petrochemical products and (iv) the gathering, transportation, marketing and storage of natural gas.

At June 30, 2010, 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, 2010, EPO owned 58.5% of Duncan Energy Partners' limited partner interests and 100% of its general partner. Due to our control of Duncan Energy Partners, its financial statements are consolidated with those of our own and our transactions with Duncan Energy Partners are eliminated in consolidation.

Note 14. Earnings Per Unit

Basic earnings per unit is computed by dividing net income or loss available to limited partner interests by the weighted-average number of distribution-bearing units outstanding during a period. Diluted earnings per unit is computed by dividing net income or loss available to limited partner interests by the sum of (i) the weighted-average number of distribution-bearing units outstanding during a period (as used in determining basic earnings per unit), (ii) the weighted-average number of Class B units outstanding during a period and (iii) the number of incremental common units resulting from the assumed exercise of dilutive unit options outstanding during a period (the "incremental option units").

In a period of net losses, the Class B units and incremental option units are excluded from the calculation of diluted earnings per unit due to their antidilutive effect. The dilutive incremental option units are calculated using the treasury stock method, which assumes that proceeds from the exercise of all in-the-money options at the end of each period are used to repurchase common units at an average market price during the period. The amount of common units remaining after the proceeds are exhausted represents the potentially dilutive effect of the securities.

The amount of net income or loss available to limited partner interests is net of our general partner's share of such earnings. The following table presents our calculation of the net income available to EPGP for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2010	2009	2010	2009
Net income attributable to Enterprise Products Partners L.P.	$ 357.2	$ 186.6	$ 735.0	$ 411.9
Less incentive earnings allocations to EPGP	(56.9)	(36.6)	(110.8)	(71.8)
Net income available after incentive earnings allocation	300.3	150.0	624.2	340.1
Multiplied by EPGP ownership interest	2.0%	2.0%	2.0%	2.0%
Standard earnings allocation to EPGP	$ 6.0	$ 3.0	$ 12.5	$ 6.8
Incentive earnings allocation to EPGP	$ 56.9	$ 36.6	$ 110.8	$ 71.8
Standard earnings allocation to EPGP	6.0	3.0	12.5	6.8
Net income available to EPGP	62.9	39.6	123.3	78.6
Two-class method adjustment (1)	1.7	1.4	4.7	2.8
Net income available to EPGP for EPU purposes	$ 64.6	$ 41.0	$ 128.0	$ 81.4

(1) FASB guidance specific to master limited partnerships has been applied for purposes of computing basic and diluted earnings per unit.

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

	For the Three Month Ended June 30,		For the Six Month Ended June 30,	
	2010	2009	2010	2009
BASIC EARNINGS PER UNIT				
Numerator				
Net income attributable to Enterprise Products Partners L.P.	$ 357.2	$ 186.6	$ 735.0	$ 411.9
Net income available to EPGP for EPU purposes	(64.6)	(41.0)	(128.0)	(81.4)
Net income available to limited partners	$ 292.6	$ 145.6	$ 607.0	$ 330.5
Denominator				
Weighted – average common units outstanding	630.1	455.8	622.4	453.3
Weighted – average restricted common units outstanding	3.7	2.6	3.5	2.2
Total	633.8	458.4	625.9	455.5
Basic earnings per unit				
Net income per unit before EPGP earnings allocation	$ 0.56	$ 0.41	$ 1.17	$ 0.91
Net income available to EPGP	(0.10)	(0.09)	(0.20)	(0.18)
Net income available to limited partners	$ 0.46	$ 0.32	$ 0.97	$ 0.73
DILUTED EARNINGS PER UNIT				
Numerator				
Net income attributable to Enterprise Products Partners L.P.	$ 357.2	$ 186.6	$ 735.0	$ 411.9
Net income available to EPGP for EPU purposes	(64.6)	(41.0)	(128.0)	(81.4)
Net income available to limited partners	$ 292.6	$ 145.6	$ 607.0	$ 330.5
Denominator				
Weighted – average common units outstanding	630.1	455.8	622.4	453.3
Weighted – average restricted common units outstanding	3.7	2.6	3.5	2.2
Class B units outstanding	4.5	--	4.5	--
Incremental option units	0.8	0.1	0.9	0.1
Total	639.1	458.5	631.3	455.6
Diluted earnings per unit				
Net income per unit before EPGP earnings allocation	$ 0.56	$ 0.41	$ 1.16	$ 0.91
Net income available to EPGP	(0.10)	(0.09)	(0.20)	(0.18)
Net income available to limited partners	$ 0.46	$ 0.32	$ 0.96	$ 0.73

Note 15. Commitments and Contingencies

Litigation

As part of our normal business activities, we or our unconsolidated affiliates are named on occasion as defendants in litigation and legal proceedings, including those arising from 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. See Note 16 for information regarding our insurance program. We are not aware of any litigation, pending or threatened, that we believe is reasonably likely to have a significant adverse effect on our consolidated financial position, results of operations or cash flows.

We have not recorded any significant reserves for litigation matters. Our evaluation of litigation contingencies is based on the facts and circumstances of each case and predicting the outcome of these matters involves substantial uncertainties. In the event the assumptions we use 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 may settle legal proceedings out of court.

In October 2009, we received notice that the Colorado Department of Public Health and Environment, through its Air Pollution Control Division, had proposed a Compliance Order on Consent with Enterprise Gas Processing, L.L.C for alleged violations of the Colorado Air Pollution and Prevention and Control Act ("Colorado Act") with respect to operations at our Meeker natural gas processing facility. The Compliance Order proposes an administrative fine of approximately $0.9 million and would require the Meeker facility to be operated in compliance with the Colorado Act. We have entered into discussions with Colorado authorities regarding the terms of the proposed Compliance Order.

In December 2008, 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 of New Mexico alleges violations of its air laws. Marathon agreed to a Consent Decree with the State of New Mexico, which was then approved by the District Court on December 21, 2009. Under the Consent Decree, Marathon paid the State of New Mexico approximately $0.6 million, agreed to $4.5 million of additional environmental projects in New Mexico and agreed to two projects for "corrective measures" at the facility. We are in discussions with Marathon regarding the responsibility for these payments. We believe that any potential payment we make will not have a material impact on our consolidated financial position, results of operations or cash flows.

On March 29, 2007, a third party struck the West Red Line of our Mid-America Pipeline ("MAPL") releasing 1,725 barrels of natural gasoline. MAPL and EPO received letters dated June 4, 2009,from the U.S. Department of Justice ("DOJ") informing them that the DOJ desired to discuss violations of the federal Clean Water Act related to the release and potential settlement of the alleged violations. We have begun discussions with the DOJ and believe that the eventual resolution of this matter will result in a civil penalty exceeding $0.1 million. While our discussions with the DOJ are still at a preliminary stage, we believe that any potential payment we make in connection with this release will not have a material impact on our consolidated financial position, results of operations or cash flows.

Regulatory Matters

Certain scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" and including carbon dioxide (which is a component of, and a product of combustion of, natural gas) and methane (which is a component of natural gas), may be contributing to global climate change and ocean acidification. On June 26, 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009 ("ACESA") which, if it were to become law, would establish an economy-wide cap-and-trade program intended to reduce the emissions of greenhouse gases by the United States and would require most significant domestic sources of greenhouse gas emissions to obtain greenhouse gas emission "allowances" corresponding to their annual emissions of greenhouse gases. The U.S. Senate has also begun consideration of various legislative proposals for controlling and reducing emissions of greenhouse gases in the United States. In addition, on December 7, 2009, the U.S. Environmental Protection Agency ("EPA") announced its finding that emissions of greenhouse gases from motor vehicles caused or contributed to climate change and presented an endangerment to human health and the environment. These findings by the EPA were the basis for motor vehicle greenhouse gas emissions standards promulgated on May 7, 2010, and may allow the agency to proceed with the adoption and implementation of additional regulations that would restrict emissions of greenhouse gases from industrial sources under existing provisions of the federal Clean Air Act. On May 13, 2010, the EPA issued a final rule setting forth a timetable for extension of its Prevention of Significant Deterioration regulatory program, applicable in certain circumstances to new and modified industrial source of air emissions, to include consideration of greenhouse gas emissions. The EPA has also received petitions requesting that the agency further expand regulation of greenhouse gas emissions from industrial sources, which, over time, may lead to additional requirements. On April 12, 2010, the EPA proposed new rules that would require the mandatory reporting of greenhouse gas emissions by pipeline operators and operators of natural gas processing and storage facilities. These rules supplement disclosures and reporting required by the EPA in its October 30, 2009 mandatory greenhouse gas reporting rule. Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases, or that establish new reporting requirements, would likely require us to incur increased operating costs, and may have an adverse effect on our financial position, results of operations and cash flows.

Contractual Obligations

Scheduled Maturities of Long-Term Debt. With the exception of (i) routine fluctuations in the balance of our consolidated revolving credit facilities, (ii) the issuance of Senior Notes X, Y and Z in May 2010 and (iii) the repayments of the Pascagoula MBFC Loan in March 2010 and Senior Notes K in June 2010, there have been no significant changes in our consolidated debt obligations since those reported in our 2009 Form 10-K. See Note 10 for additional information regarding our consolidated debt obligations.

Operating Lease Obligations. Lease and rental expense included in costs and expenses was $15.9 million and $14.8 million during the three months ended June 30, 2010 and 2009, respectively. For the six months ended June 30, 2010 and 2009, lease and rental expense was $32.3 million and $28.8 million, respectively. There have been no material changes in our operating lease commitments since those reported in our 2009 Form 10-K.

Purchase Obligations. There have been no material changes in our consolidated purchase obligations since those reported in our 2009 Form 10-K.

Other Claims

As part of our normal business activities with joint venture partners, customers and suppliers, we occasionally have claims made against us as a result of disputes related to contractual agreements or other communications. As of June 30, 2010, claims against us totaled approximately $19.7 million. These matters are in various stages of assessment and the ultimate outcome of such disputes cannot be reasonably estimated at this time. However, in our opinion, the likelihood of a material adverse outcome to us resulting from such disputes is remote. Accordingly, we have not recorded any accruals for loss contingencies related to these matters.

Centennial Guarantees

We have certain guarantee obligations in connection with our ownership interest in Centennial, which owns a refined products pipeline system that extends from the Texas Gulf Coast to central Illinois. We guaranteed one-half of Centennial's debt obligations, which obligates us to an estimated payment of

$57.7 million in the event of a default by Centennial. As of June 30, 2010, we have a recorded liability of $8.1 million representing the estimated fair value of our share of the Centennial debt guaranty.

In lieu of Centennial procuring insurance to satisfy third-party claims arising from a catastrophic event, we and Centennial's other joint venture partner have entered a limited cash call agreement. We are obligated to contribute up to a maximum of $50.0 million (in proportion to our 50% ownership interest in Centennial) in the event of a catastrophic event. At June 30, 2010, we have a recorded liability of $3.5 million representing the estimated fair value of our cash call guaranty. Our cash contributions to Centennial under the agreement may be covered by our other insurance policies depending on the nature of the catastrophic event.

Note 16. Significant Risks and Uncertainties

Insurance-Related Risks

We participate as a named insured in EPCO's insurance program, which provides us with property damage, business interruption and other coverages, the scope and amounts of which we believe are customary and prudent for the nature and extent of our operations. While we believe EPCO maintains adequate insurance coverage on our behalf, insurance will not cover every type of damage or interruption that might occur. If we were to incur a significant liability for which we were not fully insured, it could have a material impact on our consolidated financial position, results of operations and cash flows. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient to reimburse us for our repair costs or lost income. Any event that interrupts the revenues generated by our consolidated operations, or which causes us to make significant expenditures not covered by insurance, could reduce our ability to pay distributions to our partners and, accordingly, adversely affect the market price of our common units.

EPCO completed its annual insurance renewal process during the second quarter of 2010, which resulted in an increase in premiums. EPCO's deductible for onshore physical damage from windstorms increased from $25.0 million per storm to $30.0 million per storm. EPCO's onshore insurance program currently provides $141.3 million of coverage per occurrence for named windstorm events compared to $150.0 million per occurrence in the prior year. With respect to offshore assets, the deductible for windstorm damage remained at $75.0 million per storm. EPCO's insurance program for offshore Gulf of Mexico assets currently provides $124.5 million of coverage in the aggregate compared to $100.0 million of coverage in the aggregate for the prior year. In addition, at EPCO's election, we now have access to an additional $17.5 million of coverage for either onshore or offshore windstorm-related damage claims. 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 offshore assets, producers continue to provide a specified level of physical damage insurance coverage for named windstorms. The producers associated with our Independence Hub and Marco Polo offshore Gulf of Mexico platforms continue to cover windstorm generated physical damage costs up to $250.0 million for each platform.

Business interruption coverage in connection with a windstorm event remains in place for onshore assets. We do not have any business interruption coverage for offshore Gulf of Mexico assets when the outage is due to a windstorm. We have business interruption coverage for both onshore and offshore assets in connection with non-windstorm events. Assets covered by business interruption insurance must be out-of-service in excess of 60 days before any allowed losses from business interruption will be covered.

The following table summarizes proceeds we received from weather-related business interruption and property damage insurance claims during the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2010	2009	2010	2009
Business interruption proceeds:				
Hurricane Ike	$ --	$ --	$ 1.1	$ --
Total business interruption proceeds	--	--	1.1	--
Property damage proceeds:				
Hurricane Katrina	--	--	--	23.2
Hurricane Rita	9.5	--	36.3	--
Hurricane Ike	--		1.9	--
Total property damage proceeds (1)	9.5	--	38.2	23.2
Total	$ 9.5	$ --	$ 39.3	$ 23.2

(1) Our operating income for the three months ended June 30, 2010 includes $9.5 million of proceeds from property damage insurance claims. For the six months ended June 30, 2010 and 2009, operating income includes $17.1 million and $0.6 million, respectively, of proceeds from property damage insurance claims. We recognize such gains when the amount of insurance proceeds from property damage insurance claims received exceed the related costs of the associated asset(s).

At June 30, 2010, we had $40.1 million of estimated property damage claims outstanding related to windstorms.

We expect to recognize a gain of approximately $70 million during the third quarter of 2010 related to cash proceeds from insurance recoveries associated with an offshore natural gas pipeline system and an offshore platform. The expected proceeds approximate the negotiated value of the covered assets, which were damaged by windstorms or other events. The expected gain represents the excess of the insurance proceeds over the carrying value of the related assets.

Note 17. 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,	
	2010	2009
Decrease (increase) in:		
Accounts and notes receivable – trade	$ 184.5	$ (235.4)
Accounts receivable – related party	10.2	36.7
Inventories	(326.4)	(658.3)
Prepaid and other current assets	(113.4)	(39.9)
Other assets	14.0	(30.6)
Increase (decrease) in:		
Accounts payable – trade	68.4	(42.1)
Accounts payable – related party	67.9	73.4
Accrued product payables	(271.8)	580.3
Accrued interest	8.7	19.4
Other current liabilities	27.6	(76.3)
Other liabilities	(6.2)	(4.7)
Net effect of changes in operating accounts	$ (336.5)	$ (377.5)

We incurred liabilities for construction in progress that had not been paid at June 30, 2010 and December 31, 2009, of $155.4 million and $182.6 million, respectively. Such amounts are not included under the caption “Capital expenditures” on the Unaudited Condensed Statements of Consolidated Cash Flows.

Third parties may be obligated to reimburse us for all or a portion of expenditures on certain of our capital projects. The majority of such arrangements are associated with projects related to pipeline construction and producer well tie-ins. These amounts are included under the caption "Contributions in aid of construction costs" on the Unaudited Condensed Statements of Consolidated Cash Flows.

Note 18. Condensed Consolidating Financial Information

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 those of its own.

EPO has issued publicly traded debt securities. Enterprise Products Partners L.P., as the parent company of EPO, guarantees the debt obligations of EPO, with the exception of Duncan Energy Partners' debt obligations and the remaining debt obligations of TEPPCO. 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. EPO's consolidated subsidiaries have no significant restrictions on their ability to pay distributions or make loans to Enterprise Products Partners L.P. See Note 10 for additional information regarding our consolidated debt obligations.

Immediately after the closing of the TEPPCO Merger, Enterprise Products Partners L.P. contributed its ownership interests in TEPPCO and TEPPCO GP to EPO. The following condensed consolidating financial information for EPO has been recast to include TEPPCO and TEPPCO GP using the same basis of presentation described in Note 1 for our consolidated financial statements.

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Balance Sheet
June 30, 2010

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Parent Company (Guarantor)	Eliminations and Adjustments	Consolidated Total
ASSETS							
Current assets:							
Cash and cash equivalents	$ 440.1	$ 58.3	$ (6.5)	$ 491.9	$ 2.6	$ --	$ 494.5
Restricted cash	17.7	1.4	--	19.1	--	--	19.1
Accounts and notes receivable, net	618.8	2,301.2	25.9	2,945.9	(2.6)	--	2,943.3
Inventories	853.7	173.9	(2.1)	1,025.5	--	--	1,025.5
Prepaid and other current assets	261.8	176.5	(15.3)	423.0	0.2	--	423.2
Total current assets	2,192.1	2,711.3	2.0	4,905.4	0.2	--	4,905.6
Property, plant and equipment, net	1,364.0	16,978.2	(10.2)	18,332.0	--	--	18,332.0
Investments in unconsolidated affiliates	20,117.3	5,937.3	(25,181.4)	873.2	10,396.2	(10,396.2)	873.2
Intangible assets, net	162.5	1,748.6	(15.0)	1,896.1	--	--	1,896.1
Goodwill	473.7	1,576.9	--	2,050.6	--	--	2,050.6
Other assets	258.3	122.5	(149.9)	230.9	--	1.1	232.0
Total assets	$ 24,567.9	$ 29,074.8	$ (25,354.5)	$ 28,288.2	$ 10,396.4	$ (10,395.1)	$ 28,289.5
LIABILITIES AND EQUITY							
Current liabilities:							
Current maturities of debt	$ --	$ 263.9	$ (8.9)	$ 255.0	$ --	$ --	$ 255.0
Accounts payable	186.9	517.6	(109.7)	594.8	--	--	594.8
Accrued product payables	1,474.8	1,661.9	(15.8)	3,120.9	--	--	3,120.9
Other current liabilities	438.7	269.5	(11.6)	696.6	--	0.1	696.7
Total current liabilities	2,100.4	2,712.9	(146.0)	4,667.3	--	0.1	4,667.4
Long-term debt	12,022.7	393.8	--	12,416.5	--	--	12,416.5
Commitments and contingencies							
Other long-term liabilities	68.9	212.5	(1.2)	280.2	--	--	280.2
Equity:							
Partners' and other owners' equity	10,375.9	22,128.5	(22,119.9)	10,384.5	10,396.4	(10,384.5)	10,396.4
Noncontrolling interests	--	3,627.1	(3,087.4)	539.7	--	(10.7)	529.0
Total equity	10,375.9	25,755.6	(25,207.3)	10,924.2	10,396.4	(10,395.2)	10,925.4
Total liabilities and equity	$ 24,567.9	$ 29,074.8	$ (25,354.5)	$ 28,288.2	$ 10,396.4	$ (10,395.1)	$ 28,289.5

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Balance Sheet
December 31, 2009

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Parent Company (Guarantor)	Eliminations and Adjustments	Consolidated Total
ASSETS							
Current assets:							
Cash and cash equivalents	$ 14.4	$ 46.3	$ (6.2)	$ 54.5	$ --	$ 0.2	$ 54.7
Restricted cash	63.1	0.5	--	63.6	--	--	63.6
Accounts and notes receivable, net	509.6	2,674.0	(45.7)	3,137.9	(0.3)	(0.2)	3,137.4
Inventories	595.4	120.3	(3.8)	711.9	--	--	711.9
Prepaid and other current assets	185.4	100.6	(6.7)	279.3	--	--	279.3
Total current assets	1,367.9	2,941.7	(62.4)	4,247.2	(0.3)	--	4,246.9
Property, plant and equipment, net	1,436.1	16,242.0	11.1	17,689.2	--	--	17,689.2
Investments in unconsolidated affiliates	18,981.2	5,912.7	(24,003.3)	890.6	9,512.4	(9,512.4)	890.6
Intangible assets, net	170.0	910.3	(15.5)	1,064.8	--	--	1,064.8
Goodwill	473.7	1,544.6	--	2,018.3	--	--	2,018.3
Other assets	287.2	131.1	(177.4)	240.9	--	0.9	241.8
Total assets	$ 22,716.1	$ 27,682.4	$ (24,247.5)	$ 26,151.0	$ 9,512.1	$ (9,511.5)	$ 26,151.6
LIABILITIES AND EQUITY							
Current liabilities:							
Accounts payable	$ 146.3	$ 551.5	$ (217.4)	$ 480.4	$ --	$ --	$ 480.4
Accrued product payables	1,842.6	1,557.3	(6.9)	3,393.0	--	--	3,393.0
Other current liabilities	403.7	274.2	(15.3)	662.6	--	--	662.6
Total current liabilities	2,392.6	2,383.0	(239.6)	4,536.0	--	--	4,536.0
Long-term debt	10,777.6	568.8	--	11,346.4	--	--	11,346.4
Commitments and contingencies							
Other long-term liabilities	17.9	209.0	--	226.9	--	--	226.9
Equity:							
Partners' and other owners' equity	9,528.0	21,058.3	(21,084.5)	9,501.8	9,512.1	(9,501.8)	9,512.1
Noncontrolling interests	--	3,463.3	(2,923.4)	539.9	--	(9.7)	530.2
Total equity	9,528.0	24,521.6	(24,007.9)	10,041.7	9,512.1	(9,511.5)	10,042.3
Total liabilities and equity	$ 22,716.1	$ 27,682.4	$ (24,247.5)	$ 26,151.0	$ 9,512.1	$ (9,511.5)	$ 26,151.6

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
Three Months Ended June 30, 2010

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Parent Company (Guarantor)	Eliminations and Adjustments	Consolidated Total
Revenues	$ 5,658.5	$ 4,787.3	$ (2,902.4)	$ 7,543.4	$ --	$ --	$ 7,543.4
Costs and expenses:							
Operating costs and expenses	5,550.4	4,325.8	(2,902.0)	6,974.2	--	--	6,974.2
General and administrative costs	2.9	32.8	--	35.7	2.2	--	37.9
Total costs and expenses	5,553.3	4,358.6	(2,902.0)	7,009.9	2.2	--	7,012.1
Equity in income of unconsolidated affiliates	419.3	42.4	(445.0)	16.7	359.4	(359.4)	16.7
Operating income	524.5	471.1	(445.4)	550.2	357.2	(359.4)	548.0
Other income (expense):							
Interest expense	(164.1)	(7.0)	2.5	(168.6)	--	--	(168.6)
Other, net	2.6	0.3	(2.5)	0.4	--	--	0.4
Total other expense, net	(161.5)	(6.7)	--	(168.2)	--	--	(168.2)
Income before provision for income taxes	363.0	464.4	(445.4)	382.0	357.2	(359.4)	379.8
Provision for income taxes	(3.4)	(3.1)	--	(6.5)	--	--	(6.5)
Net income	359.6	461.3	(445.4)	375.5	357.2	(359.4)	373.3
Net income attributable to noncontrolling interests	--	6.4	(22.7)	(16.3)	--	0.2	(16.1)
Net income attributable to entity	$ 359.6	$ 467.7	$ (468.1)	$ 359.2	$ 357.2	$ (359.2)	$ 357.2

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
Three Months Ended June 30, 2009

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Parent Company (Guarantor)	Eliminations and Adjustments	Consolidated Total
Revenues	$ 3,750.6	$ 3,418.2	$ (1,734.5)	$ 5,434.3	$ --	$ --	$ 5,434.3
Costs and expenses:							
Operating costs and expenses	3,693.7	2,997.8	(1,667.0)	5,024.5	--	--	5,024.5
General and administrative costs	4.0	37.7	--	41.7	4.4	--	46.1
Total costs and expenses	3,697.7	3,035.5	(1,667.0)	5,066.2	4.4	--	5,070.6
Equity in income of unconsolidated affiliates	258.9	(45.1)	(204.2)	9.6	191.0	(191.0)	9.6
Operating income	311.8	337.6	(271.7)	377.7	186.6	(191.0)	373.3
Other income (expense):							
Interest expense	(122.6)	(38.9)	3.0	(158.5)	--	--	(158.5)
Other, net	2.9	0.9	(3.0)	0.8	--	--	0.8
Total other expense, net	(119.7)	(38.0)	--	(157.7)	--	--	(157.7)
Income before provision for income taxes	192.1	299.6	(271.7)	220.0	186.6	(191.0)	215.6
Provision for income taxes	(1.2)	(1.9)	--	(3.1)	--	--	(3.1)
Net income	190.9	297.7	(271.7)	216.9	186.6	(191.0)	212.5
Net income attributable to noncontrolling interests	--	12.4	(38.5)	(26.1)	--	0.2	(25.9)
Net income attributable to entity	$ 190.9	$ 310.1	$ (310.2)	$ 190.8	$ 186.6	$ (190.8)	$ 186.6

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
Six Months Ended June 30, 2010

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Parent Company (Guarantor)	Eliminations and Adjustments	Consolidated Total
Revenues	$ 12,615.9	$ 9,400.3	$ (5,928.3)	$ 16,087.9	$ --	$ --	$ 16,087.9
Costs and expenses:							
Operating costs and expenses	12,396.5	8,478.1	(5,928.5)	14,946.1	--	--	14,946.1
General and administrative costs	2.9	68.4	--	71.3	4.2	--	75.5
Total costs and expenses	12,399.4	8,546.5	(5,928.5)	15,017.4	4.2	--	15,021.6
Equity in income of unconsolidated affiliates	833.0	95.9	(896.2)	32.7	739.2	(739.2)	32.7
Operating income	1,049.5	949.7	(896.0)	1,103.2	735.0	(739.2)	1,099.0
Other income (expense):							
Interest expense	(307.9)	(14.4)	5.1	(317.2)	--	--	(317.2)
Other, net	5.4	0.2	(5.1)	0.5	--	--	0.5
Total other expense, net	(302.5)	(14.2)	--	(316.7)	--	--	(316.7)
Income before provision for income taxes	747.0	935.5	(896.0)	786.5	735.0	(739.2)	782.3
Provision for income taxes	(8.3)	(6.9)	--	(15.2)	--	--	(15.2)
Net income	738.7	928.6	(896.0)	771.3	735.0	(739.2)	767.1
Net income attributable to noncontrolling interests	--	6.6	(39.0)	(32.4)	--	0.3	(32.1)
Net income attributable to entity	$ 738.7	$ 935.2	$ (935.0)	$ 738.9	$ 735.0	$ (738.9)	$ 735.0

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
Six Months Ended June 30, 2009

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Parent Company (Guarantor)	Eliminations and Adjustments	Consolidated Total
Revenues	$ 7,432.3	$ 6,276.4	$ (3,387.5)	$ 10,321.2	$ --	$ --	$ 10,321.2
Costs and expenses:							
Operating costs and expenses	7,273.8	5,446.5	(3,319.2)	9,401.1	--	--	9,401.1
General and administrative costs	5.9	68.7	--	74.6	6.4	--	81.0
Total costs and expenses	7,279.7	5,515.2	(3,319.2)	9,475.7	6.4	--	9,482.1
Equity in income of unconsolidated affiliates	503.1	10.3	(496.4)	17.0	418.3	(418.3)	17.0
Operating income	655.7	771.5	(564.7)	862.5	411.9	(418.3)	856.1
Other income (expense):							
Interest expense	(239.2)	(78.0)	6.2	(311.0)	--	--	(311.0)
Other, net	6.2	2.0	(6.2)	2.0	--	--	2.0
Total other expense, net	(233.0)	(76.0)	--	(309.0)	--	--	(309.0)
Income before provision for income taxes	422.7	695.5	(564.7)	553.5	411.9	(418.3)	547.1
Provision for income taxes	(4.5)	(14.6)	--	(19.1)	--	--	(19.1)
Net income	418.2	680.9	(564.7)	534.4	411.9	(418.3)	528.0
Net income attributable to noncontrolling interests	--	15.0	(131.3)	(116.3)	--	0.2	(116.1)
Net income attributable to entity	$ 418.2	$ 695.9	$ (696.0)	$ 418.1	$ 411.9	$ (418.1)	$ 411.9

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Cash Flows
Six Months Ended June 30, 2010

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Parent Company (Guarantor)	Eliminations and Adjustments	Consolidated Total
Operating activities:							
Net income	$ 738.7	$ 928.6	$ (896.0)	$ 771.3	$ 735.0	$ (739.2)	$ 767.1
Adjustments to reconcile net income to cash provided by operating activities:							
Depreciation, amortization and accretion	45.7	406.4	(0.7)	451.4	--	--	451.4
Non-cash asset impairment charges	--	1.5	--	1.5	--	--	1.5
Equity in income of unconsolidated affiliates	(833.0)	(95.9)	896.2	(32.7)	(739.2)	739.2	(32.7)
Distributions received from unconsolidated affiliates	88.0	85.4	(114.6)	58.8	838.7	(838.7)	58.8
Operating lease expenses paid by EPCO	0.3	--	--	0.3	--	--	0.3
Gains from asset sales and related transactions	(0.1)	(5.6)	--	(5.7)	--	--	(5.7)
Deferred income tax expense	0.3	1.1	--	1.4	--	(0.1)	1.3
Changes in fair market value of derivative instruments	(3.7)	(1.3)	--	(5.0)	--	--	(5.0)
Effect of pension settlement recognition	--	(0.2)	--	(0.2)	--	--	(0.2)
Net effect of changes in operating accounts	388.1	(866.4)	140.5	(337.8)	1.4	(0.1)	(336.5)
Cash provided by operating activities	424.3	453.6	25.4	903.3	835.9	(838.9)	900.3
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	63.2	(801.3)	--	(738.1)	--	--	(738.1)
Decrease (increase) in restricted cash	53.5	(0.9)	--	52.6	--	--	52.6
Cash used for business combinations	(2.2)	(1,218.0)	--	(1,220.2)	--	--	(1,220.2)
Investments in unconsolidated affiliates	(1,448.2)	(9.6)	1,447.6	(10.2)	(988.9)	988.9	(10.2)
Repayment of affiliate loan	(45.6)	45.6	--	--	--	--	--
Proceeds from asset sales and related transactions	0.2	23.9	--	24.1	--	--	24.1
Cash used in investing activities	(1,379.1)	(1,960.3)	1,447.6	(1,891.8)	(988.9)	988.9	(1,891.8)
Financing activities:							
Borrowings under debt agreements	3,435.7	103.1	--	3,538.8	--	--	3,538.8
Repayments of debt	(2,191.9)	(23.1)	--	(2,215.0)	--	--	(2,215.0)
Cash distributions paid to partners	(838.7)	(109.7)	109.7	(838.7)	(830.9)	838.7	(830.9)
Unit option-related reimbursements to EPCO	--	--	--	--	(2.2)	--	(2.2)
Cash distributions paid to noncontrolling interests	--	(52.5)	15.9	(36.6)	--	--	(36.6)
Net cash proceeds from issuance of common units	--	--	--	--	990.1	--	990.1
Cash proceeds from exercise of unit options	--	--	--	--	1.6	--	1.6
Cash contributions from members	988.9	1,387.6	(1,387.6)	988.9	--	(988.9)	--
Cash contributions from noncontrolling interests	--	213.2	(211.3)	1.9	--	--	1.9
Other financing activities	(13.5)	--	--	(13.5)	(3.0)	--	(16.5)
Cash provided by financing activities	1,380.5	1,518.6	(1,473.3)	1,425.8	155.6	(150.2)	1,431.2
Effect of exchange rate changes on cash	--	0.1	--	0.1	--	--	0.1
Net change in cash and cash equivalents	425.7	11.9	(0.3)	437.3	2.6	(0.2)	439.7
Cash and cash equivalents, January 1	14.4	46.3	(6.2)	54.5	--	0.2	54.7
Cash and cash equivalents, June 30	$ 440.1	$ 58.3	$ (6.5)	$ 491.9	$ 2.6	$ --	$ 494.5

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Cash Flows
Six Months Ended June 30, 2009

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Parent Company (Guarantor)	Eliminations and Adjustments	Consolidated Total
Operating activities:							
Net income	$ 418.2	$ 680.9	$ (564.7)	$ 534.4	$ 411.9	$ (418.3)	$ 528.0
Adjustments to reconcile net income to cash provided by operating activities:							
Depreciation, amortization and accretion	38.9	370.1	(1.3)	407.7	--	--	407.7
Non-cash asset impairment charges	--	2.3	--	2.3	--	--	2.3
Equity in income of unconsolidated affiliates	(503.1)	(10.3)	496.4	(17.0)	(418.3)	418.3	(17.0)
Distributions received from unconsolidated affiliates	172.9	123.1	(262.5)	33.5	576.1	(576.1)	33.5
Operating lease expenses paid by EPCO	0.3	--	--	0.3	--	--	0.3
Gains from asset sales and related transactions	--	(0.4)	--	(0.4)	--	--	(0.4)
Loss on forfeiture of investment in Texas Offshore Port System	--	68.4	--	68.4	--	--	68.4
Deferred income tax expense	(0.7)	2.7	--	2.0	--	(0.2)	1.8
Changes in fair market value of derivative instruments	(9.6)	(2.4)	--	(12.0)	--	--	(12.0)
Effect of pension settlement recognition	--	(0.1)	--	(0.1)	--	--	(0.1)
Net effect of changes in operating accounts	95.4	(603.7)	133.4	(374.9)	(2.5)	(0.1)	(377.5)
Cash provided by operating activities	212.3	630.6	(198.7)	644.2	567.2	(576.4)	635.0
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(98.5)	(725.4)	--	(823.9)	--	--	(823.9)
Decrease in restricted cash	19.4	--	--	19.4	--	--	19.4
Cash used for business combinations	(23.7)	(50.0)	--	(73.7)	--	--	(73.7)
Acquisition of intangible assets	--	(1.4)	--	(1.4)	--	--	(1.4)
Investments in unconsolidated affiliates	(243.4)	(26.9)	260.5	(9.8)	(398.5)	398.5	(9.8)
Proceeds from asset sales and related transactions	--	0.6	--	0.6	--	--	0.6
Other investing activities	--	1.5	--	1.5	--	--	1.5
Cash used in investing activities	(346.2)	(801.6)	260.5	(887.3)	(398.5)	398.5	(887.3)
Financing activities:							
Borrowings under debt agreements	2,747.0	797.4	--	3,544.4	--	--	3,544.4
Repayments of debt	(2,415.6)	(608.0)	--	(3,023.6)	--	--	(3,023.6)
Cash distributions paid to partners	(576.1)	(208.1)	208.1	(576.1)	(566.1)	576.1	(566.1)
Unit option-related reimbursements to EPCO	--	--	--	--	(0.3)	--	(0.3)
Cash distributions paid to noncontrolling interests	--	(227.1)	16.4	(210.7)	--	0.1	(210.6)
Net cash proceeds from issuance of common units	--	--	--	--	398.6	--	398.6
Cash proceeds from exercise of unit options	--	--	--	--	0.2	--	0.2
Cash contributions from members	398.5	171.5	(171.5)	398.5	--	(398.5)	--
Cash contributions from noncontrolling interests	--	232.4	(108.1)	124.3	--	--	124.3
Other financing activities	(5.0)	(0.4)	--	(5.4)	--	--	(5.4)
Cash provided by financing activities	148.8	157.7	(55.1)	251.4	(167.6)	177.7	261.5
Effect of exchange rate changes on cash	--	(2.2)	--	(2.2)	--	--	(2.2)
Net change in cash and cash equivalents	14.9	(13.3)	6.7	8.3	1.1	(0.2)	9.2
Cash and cash equivalents, January 1	1.0	69.7	(9.4)	61.3	0.2	0.2	61.7
Cash and cash equivalents, June 30	$ 15.9	$ 54.2	$ (2.7)	$ 67.4	$ 1.3	$ --	$ 68.7

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

For the three and six months ended June 30, 2010 and 2009.

The following information should be read in conjunction with our unaudited condensed consolidated financial statements and accompanying notes included in this quarterly report on Form 10-Q. 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 annual report on Form 10-K for the year ended December 31, 2009 (the "2009 Form 10-K"). Our financial statements have been prepared in accordance with generally accepted accounting principles ("GAAP") in the United States.

Key References Used in this Quarterly Report

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. Enterprise Products Partners conducts substantially all of its business through EPO and its consolidated subsidiaries. References to "EPGP" mean Enterprise Products GP, LLC, which is our general partner.

References to "Duncan Energy Partners" mean Duncan Energy Partners L.P., which is a consolidated subsidiary of EPO. Duncan Energy Partners 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 "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 "Enterprise GP Holdings" mean Enterprise GP Holdings L.P., a publicly traded Delaware limited partnership, the units of which are listed on the NYSE under the ticker symbol "EPE." Enterprise GP Holdings owns EPGP. The general partner of Enterprise GP Holdings is EPE Holdings, LLC ("EPE Holdings"), which is a wholly owned subsidiary of Dan Duncan LLC. The membership interests of Dan Duncan LLC are owned of record by a voting trust formed on April 26, 2006, pursuant to the Dan Duncan LLC Voting Trust Agreement dated April 26, 2006 (the "DD LLC Voting Trust Agreement"), among Dan Duncan LLC and Dan L. Duncan (as the record owner of all of the membership interests of Dan Duncan LLC immediately prior to the entering into of the DD LLC Voting Trust Agreement and as the initial sole voting trustee).

Immediately upon Mr. Duncan's death on March 29, 2010, voting and dispositive control of all of the membership interests of Dan Duncan LLC was transferred pursuant to the DD LLC Voting Trust Agreement to three voting trustees. The current voting trustees under the DD LLC Voting Trust Agreement (the "DD LLC Trustees") are: (i) Randa Duncan Williams, Mr. Duncan's oldest daughter, who is also a director of EPE Holdings; (ii) Dr. Ralph S. Cunningham, who is currently the President and Chief Executive Officer ("CEO") of EPE Holdings; and (iii) Richard H. Bachmann, who is currently an Executive Vice President, the Chief Legal Officer and Secretary of EPGP and one of three managers of Dan Duncan LLC. Dr. Cunningham and Mr. Bachmann are also currently directors of EPE Holdings.

The DD LLC Voting Trust Agreement requires that there always be two "Independent Voting Trustees" serving. If Mr. Bachmann or Dr. Cunningham fail to qualify or cease to serve, then the substitute or successor Independent Voting Trustee(s) will be appointed by the then-serving Independent Voting Trustee, provided that if no Independent Voting Trustee is then serving or if a vacancy in a trusteeship of an Independent Voting Trustee is not filled within ninety days of the vacancy's occurrence, the CEO of EPGP will appoint the successor Independent Voting Trustee(s).

The DD LLC Voting Trust Agreement also provides for a "Duncan Voting Trustee." The Duncan Voting Trustee is appointed by the children of Mr. Duncan acting by a majority or, if less than three children of Mr. Duncan are then living, unanimously. If for any reason no descendent of Mr. Duncan is appointed as the Duncan Voting Trustee, then such trusteeship will remain vacant until such time as a Duncan Voting Trustee is appointed in the manner provided above. If a Duncan Voting Trustee for any reason ceases to serve, his or her successor shall be appointed by the children of Mr. Duncan acting by majority or, if less than three children of Mr. Duncan are then living, unanimously. Ms. Williams is currently the Duncan Voting Trustee.

The DD LLC Trustees are required to treat for all purposes whatsoever the member party to the DD LLC Voting Trust Agreement as the beneficial owner of the membership interests of Dan Duncan LLC. The estate of Mr. Duncan became the sole member party to the DD LLC Voting Trust Agreement upon the death of Mr. Duncan on March 29, 2010. However, the DD LLC Trustees collectively are the record owners of the Dan Duncan LLC membership interests and possess and are entitled to exercise all rights and powers of absolute ownership thereof and to vote, assent or consent with respect thereto and to take party in and consent to any corporate or members' actions (except those actions, if any, to which the DD LLC Trustees may not legally consent) and subject to the provisions of the DD LLC Voting Trust Agreement, to receive dividends and distributions on the Dan Duncan LLC membership interests. Except as otherwise provided in the DD LLC Voting Trust Agreement, all actions taken by the DD LLC Trustees are by majority vote.

The DD LLC Trustees serve in such capacity without compensation, but they are entitled to incur reasonable charges and expenses deemed necessary and proper for administering the DD LLC Voting Trust Agreement and to reimbursement and indemnification.

The DD LLC Voting Trust Agreement will terminate when (i) the descendants of Mr. Duncan, and entities directly or indirectly controlled by or held for the benefit of any such descendant, no longer own any capital stock of EPCO (as defined below); or (ii) upon such earlier date designated by the DD LLC Trustees by an instrument in writing delivered to the member party to the DD LLC Voting Trust Agreement.

On April 27, 2010, the independent co-executors for the estate of Mr. Duncan were appointed by the probate court. The independent co-executors are Mr. Bachmann, Dr. Cunningham and Ms. Williams, who are the same persons as the current DD LLC Trustees and voting trustees under a separate voting trust agreement relating to a majority of EPCO's outstanding shares with voting rights (as more fully described below).

References to "EPCO" mean Enterprise Products Company (formerly EPCO, Inc.) and its privately held affiliates. Prior to Mr. Duncan's death, we, EPO, Duncan Energy Partners, DEP GP, EPGP, Enterprise GP Holdings and EPE Holdings were affiliates under the common control of Mr. Duncan, since he was the controlling shareholder of EPCO and the controlling member of Dan Duncan LLC. A majority of the outstanding voting capital stock of EPCO is owned of record by a voting trust formed on April 26, 2006, pursuant to the EPCO Inc. Voting Trust Agreement (the "EPCO Voting Trust Agreement"), among EPCO and Mr. Duncan (as the record owner of a majority of the outstanding voting capital stock of EPCO immediately prior to the entering into of the EPCO Voting Trust Agreement and as the initial sole voting trustee).

Immediately upon Mr. Duncan's death, voting and dispositive control of such majority of the outstanding voting capital stock of EPCO was transferred pursuant to the EPCO Voting Trust Agreement to three voting trustees (the "EPCO Trustees"). The current EPCO Trustees are: (i) Ms. Williams, who serves as Chairman of EPCO; (ii) Dr. Cunningham, who serves as a Vice Chairman of EPCO; and (iii) Mr. Bachmann, who serves as the President, CEO and Chief Legal Officer of EPCO. Ms. Williams, Dr. Cunningham and Mr. Bachmann are also currently directors of EPCO. The current EPCO Trustees are the same as the current DD LLC Trustees, which control Dan Duncan LLC. The current EPCO Trustees are also the same persons as the individuals appointed on April 27, 2010 as the independent co-executors of the estate of Mr. Duncan. At June 30, 2010, Dan Duncan LLC and EPCO beneficially owned approximately 18% and 57%, respectively, of the outstanding units representing limited partner interests of Enterprise GP Holdings.

References to "TEPPCO" and "TEPPCO GP" mean TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (which is the general partner of TEPPCO), respectively, prior to their mergers with our subsidiaries on October 26, 2009. We refer to such related mergers both individually and in the aggregate as the ("TEPPCO Merger").

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") and, effective May 26, 2010, Regency Energy Partners LP ("RGNC"). 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." ETP is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "ETP." RGNC is a publicly traded Delaware limited partnership, the common units of which are traded on the NASDAQ stock market under the ticker symbol "RGNC." The general partner of Energy Transfer Equity is LE GP, LLC.

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 2009 Form 10-K and in Part II, Item 1A of our quarterly report on Form 10-Q for the quarter ended March 31, 2010 and this quarterly report on Form 10-Q. 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.

Overview of Business

We are a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "EPD." We were formed in April 1998 to own and operate certain natural gas liquids ("NGLs") related businesses of EPCO. We are a leading North American provider of midstream energy services to producers and consumers of natural gas, NGLs, crude oil, refined products and petrochemicals. 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 with domestic consumers and international markets. The partnership's assets include: 49,100 miles of onshore and offshore pipelines; approximately 200 MMBbls of storage capacity for NGLs, refined products and crude oil; and 27 bcf of natural gas storage capacity.

Our midstream energy operations include: natural gas transportation, gathering, processing and storage; NGL transportation, fractionation, storage, and import and export terminaling; crude oil and refined products transportation, storage, and terminaling; offshore production platforms; petrochemical transportation and storage; and a marine transportation business that operates primarily on the United States inland and Intracoastal Waterway systems and in the Gulf of Mexico. We have five reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services and (v) Petrochemical & Refined Products Services. Our business segments reflect the manner in which these businesses are managed and reviewed by the CEO of our general partner.

We are owned 98% by our limited partners and 2% by our general partner, EPGP. We, EPGP, Enterprise GP Holdings, EPE Holdings, EPCO and Dan Duncan LLC are affiliates and under the collective common control of the DD LLC Trustees and the EPCO Trustees. We have no employees. All of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to an administrative services agreement or other service providers.

Basis of Financial Statement Presentation

On October 26, 2009, the related mergers of our wholly owned subsidiaries with TEPPCO and TEPPCO GP were completed. As a result, our consolidated financial statements and business segments were recast to reflect the TEPPCO Merger. Due to common control considerations, the TEPPCO Merger was accounted for at historical costs as a reorganization of entities under common control in a manner similar to a pooling of interests. Our consolidated financial statements for periods prior to the TEPPCO Merger reflect the combined financial information of Enterprise Products Partners, TEPPCO and TEPPCO GP on a 100% basis. Third-party and related party ownership interests in TEPPCO and TEPPCO GP are presented as "Former owners of TEPPCO," which is a component of noncontrolling interest.

There was no change in net income attributable to Enterprise Products Partners L.P. for periods prior to the TEPPCO Merger since the net income attributable to TEPPCO and TEPPCO GP for these periods was allocated to noncontrolling interests. Additionally, there was no change in our reported earnings per unit ("EPU") for such periods.

The following table reconciles our recast consolidated revenues and total segment gross operating margin, which is a non-GAAP financial performance measure, to our pre-merger reported amounts for the periods indicated:

	For the Three Months Ended June 30, 2009		For the Six Months Ended June 30, 2009	
Total revenues, as previously reported	$	3,507.9	$	6,931.0
Revenues from TEPPCO		1,913.3		3,370.8
Revenues from Jonah Gas Gathering Company ("Jonah") (1)		61.2		120.6
Eliminations (2)		(48.1)		(101.2)
Total revenues, as recast and currently reported	$	5,434.3	$	10,321.2
Total segment gross operating margin, as previously reported	$	509.2	$	1,057.9
Gross operating margin from TEPPCO		98.9		253.0
Gross operating margin from Jonah		43.5		86.6
Eliminations (3)		(29.5)		(61.3)
Total segment gross operating margin, as recast and currently reported	$	622.1	$	1,336.2

(1) Prior to the TEPPCO Merger, we and TEPPCO were joint venture partners in Jonah. As a result of the TEPPCO Merger, Jonah became a consolidated subsidiary of ours.
(2) Represents the elimination of revenues between Enterprise Products Partners, TEPPCO and Jonah as appropriate in consolidation.
(3) Represents the elimination of equity earnings from Jonah recorded by Enterprise Products Partners and TEPPCO as appropriate in consolidation.

Significant Recent Developments

The following information highlights significant developments since January 1, 2010 through the date of this filing, including (i) information relevant to an understanding of our financial condition, changes in financial condition or results of operations, and (ii) certain unusual or infrequent events or transactions and known trends or uncertainties that have had or that we reasonably expect may have a material impact on our revenues or income from continuing operations. For a discussion of the offshore drilling moratorium and other regulatory matters, see Part II, Item 1A "Risk Factors."

Expansion of Eagle Ford Shale Capabilities with New Construction Projects

In June 2010, we announced several new construction projects that will further extend and expand our natural gas and NGL infrastructure in south Texas and Mont Belvieu, Texas to accommodate growing production volumes from the Eagle Ford Shale supply basin in South Texas. As part of the initiative, we plan to install approximately 350 miles of pipelines, build a new natural gas processing facility and add a new 75 MBPD NGL fractionator at our Mont Belvieu complex near the Houston Ship Channel. These projects are expected to be completed in early 2012.

The planned construction includes an expansion of our Eagle Ford east-west rich natural gas mainline that will involve adding three additional pipeline segments totaling 168 miles. Upon completion, the rich gas mainline system and associated laterals will consist of approximately 300 miles of pipelines representing gathering and transportation capacity of more than 600 MMcf/d. The east end of the Eagle Ford mainline will terminate at a new natural gas complex we plan to build that will produce mixed NGLs in excess of 60 MBPD. Takeaway capacity for residue gas from the new processing facility will be provided by a combination of our existing infrastructure and construction of additional natural gas pipelines, including a new 64-mile, 30-inch diameter residue gas line from the cryogenic facility to our Wilson natural gas storage facility.

Transportation of mixed NGLs from the new processing facility to the Mont Belvieu complex will be accomplished by expanding our infrastructure, highlighted by the planned construction of a new 127-mile, 12-inch diameter pipeline. The new NGL pipeline will have an initial capacity of more than 60 MBPD, readily expandable to over 120 MBPD. To accommodate the increased volumes from the Eagle

Ford Shale and other producing regions, we are moving forward with plans to construct a fifth NGL fractionator at our Mont Belvieu complex with a design capacity of 75 MBPD. The addition of this fifth unit will increase fractionation capacity at our Mont Belvieu complex to approximately 375 MBPD.

Along with the natural gas and NGL projects, we continue to move forward on the expansion of our crude oil pipeline system into the Eagle Ford Shale supply basin. The 140-mile pipeline is supported by a long-term transportation agreement and progress is being made with other producers to provide crude oil transportation services through additional connections to the pipeline. The expansion is expected to be completed in the fourth quarter of 2011.

Operations Commence at New Port Arthur Refined Products Storage Facility

In June 2010, we announced that the partnership's refined products storage facility in Port Arthur, Texas, which was built to support the expansion of a nearby refinery, had commenced commercial operations and received its first deliveries. The new tank farm serves as the sole distribution point for output from the refinery as part of a 15-year throughput and volume dedication agreement.

Our storage facility, which represents an investment of approximately $330.0 million, features 20 storage tanks with 5.4 MMBbls of capacity for gasoline, diesel and jet fuel. In addition, five pipelines, each approximately five miles in length, transport the various products from the refinery to the storage site. Distribution interconnects provide access to major refined products pipelines, including our Enterprise TE Products Pipeline.

Acquisition of State Line and Fairplay Natural Gas Gathering Systems

On May 4, 2010, we acquired 100% ownership of the State Line and Fairplay natural gas gathering systems and related assets from M2 Midstream LLC ("Momentum") for approximately $1.2 billion in cash. The effective date of the acquisition was May 1, 2010. These systems are located in northwest Louisiana and east Texas and gather natural gas produced from the Haynesville/Bossier shales and the Cotton Valley and Taylor sand formations. We used a portion of the net proceeds from our April 2010 equity offering, together with borrowings under EPO's Multi-Year Revolving Credit Facility, to pay for this acquisition.

The State Line system is located in Desoto and Caddo Parishes, Louisiana and Panola County, Texas. The system currently includes approximately 188 miles of natural gas gathering pipelines having an aggregate gathering capacity of approximately 700 MMcf/d and two treating facilities. The State Line system began operations in February 2009 and is currently gathering approximately 500 MMcf/d of natural gas. The Fairplay system is located in Rusk, Panola, Gregg and Nacogdoches counties, Texas. The system includes approximately 249 miles of natural gas gathering pipelines (including approximately 62 miles leased from third parties) having an aggregate gathering capacity of approximately 285 MMcf/d. The Fairplay system is currently gathering approximately 175 MMcf/d of natural gas. Operations related to the Fairplay system include natural gas processing activities provided under contract at third-party processing facilities. The State Line and Fairplay systems are supported by long-term acreage dedication agreements totaling approximately 210,000 acres, as well as volumetric commitments from producers.

The addition of the State Line system complements the Haynesville Extension of our Acadian Gas pipeline system. The Haynesville Extension, which is under development, is expected to provide shippers with both production takeaway capacity from the growing Haynesville Shale and flexible options for reaching attractive markets, including access to nine interstate gas pipeline systems. The Fairplay system is expected to extend our asset base through planned future interconnects with our Texas Intrastate System, along with supporting deliveries of NGLs into our Panola pipeline, and to our fractionation, storage and distribution complex in Mont Belvieu, Texas.

Results of Operations

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 indicated:

	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)
2009									
1st Quarter	$4.91	$43.31	$0.36	$0.68	$0.87	$0.97	$0.96	$0.26	$0.20
2nd Quarter	$3.51	$59.79	$0.43	$0.73	$0.93	$1.11	$1.21	$0.34	$0.28
3rd Quarter	$3.39	$68.24	$0.47	$0.87	$1.12	$1.19	$1.42	$0.48	$0.43
4th Quarter	$4.16	$76.19	$0.67	$1.09	$1.39	$1.49	$1.64	$0.50	$0.44
2009 Averages	$3.99	$61.88	$0.48	$0.84	$1.08	$1.19	$1.31	$0.39	$0.34
2010									
1st Quarter	$5.30	$78.72	$0.73	$1.24	$1.52	$1.64	$1.82	$0.63	$0.54
2nd Quarter	$4.09	$78.03	$0.55	$1.08	$1.47	$1.58	$1.81	$0.65	$0.44
2010 Averages	$4.70	$78.37	$0.64	$1.16	$1.49	$1.61	$1.82	$0.64	$0.49

(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 as measured on the New York Mercantile Exchange ("NYMEX").

The following table presents our material average throughput, production and processing volumetric data for the periods indicated. 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,	
	2010	2009	2010	2009
NGL Pipelines & Services, net:				
NGL transportation volumes (MBPD)	2,194	1,993	2,217	2,057
NGL fractionation volumes (MBPD)	463	459	468	450
Equity NGL production (MBPD)	125	118	124	116
Fee-based natural gas processing (MMcf/d)	2,985	2,714	2,833	2,908
Onshore Natural Gas Pipelines & Services, net:				
Natural gas transportation volumes (BBtus/d)	11,418	10,672	11,300	10,506
Onshore Crude Oil Pipelines & Services, net:				
Crude oil transportation volumes (MBPD)	678	750	675	698
Offshore Pipelines & Services, net:				
Natural gas transportation volumes (BBtus/d)	1,312	1,460	1,359	1,501
Crude oil transportation volumes (MBPD)	322	244	338	219
Platform natural gas processing (MMcf/d)	568	753	600	765
Platform crude oil processing (MBPD)	17	10	18	6
Petrochemical & Refined Products Services, net:				
Butane isomerization volumes (MBPD)	99	100	86	95
Propylene fractionation volumes (MBPD)	79	67	79	67
Octane enhancement production volumes (MBPD)	13	10	12	7
Transportation volumes, primarily refined products and petrochemicals (MBPD)	786	788	795	814
Total, net:				
NGL, crude oil, refined products and petrochemical transportation volumes (MBPD)	3,980	3,775	4,025	3,788
Natural gas transportation volumes (BBtus/d)	12,730	12,132	12,659	12,007
Equivalent transportation volumes (MBPD) (1)	7,330	6,968	7,356	6,948

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

Comparison of Results of Operations

The following table summarizes the key components of our results of operations for the periods indicated (dollars in millions):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2010	2009	2010	2009
Revenues	$ 7,543.4	$ 5,434.3	$ 16,087.9	$ 10,321.2
Operating costs and expenses	6,974.2	5,024.5	14,946.1	9,401.1
General and administrative costs	37.9	46.1	75.5	81.0
Equity in income of unconsolidated affiliates	16.7	9.6	32.7	17.0
Operating income	548.0	373.3	1,099.0	856.1
Interest expense	168.6	158.5	317.2	311.0
Provision for income taxes	6.5	3.1	15.2	19.1
Net income	373.3	212.5	767.1	528.0
Net income attributable to noncontrolling interests	16.1	25.9	32.1	116.1
Net income attributable to Enterprise Products Partners L.P.	357.2	186.6	735.0	411.9

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2010	2009	2010	2009
Gross operating margin by segment:				
NGL Pipelines & Services	$ 441.0	$ 363.8	$ 878.3	$ 714.7
Onshore Natural Gas Pipelines & Services	106.9	121.2	237.2	283.1
Onshore Crude Oil Pipelines & Services	25.9	42.1	52.6	92.6
Offshore Pipelines & Services	82.8	(1.1)	163.9	60.2
Petrochemical & Refined Products Services	158.1	96.1	278.1	185.6
Total segment gross operating margin	$ 814.7	$ 622.1	$ 1,610.1	$ 1,336.2

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. For additional information regarding our business segments, see Note 12 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2010	2009	2010	2009
NGL Pipelines & Services:				
Sales of NGLs	$ 2,804.4	$ 2,260.0	$ 6,468.5	$ 4,512.2
Sales of other petroleum and related products	0.7	0.4	1.2	0.9
Midstream services	174.2	143.2	355.9	310.9
Total	2,979.3	2,403.6	6,825.6	4,824.0
Onshore Natural Gas Pipelines & Services:				
Sales of natural gas	655.6	497.4	1,630.8	1,054.0
Midstream services	189.3	181.5	375.6	358.4
Total	844.9	678.9	2,006.4	1,412.4
Onshore Crude Oil Pipelines & Services:				
Sales of crude oil	2,603.4	1,709.0	4,970.7	2,954.8
Midstream services	25.9	18.0	45.2	42.1
Total	2,629.3	1,727.0	5,015.9	2,996.9
Offshore Pipelines & Services:				
Sales of natural gas	0.4	0.3	0.8	0.6
Sales of crude oil	1.9	0.9	4.0	1.1
Midstream services	85.0	76.1	171.1	144.1
Total	87.3	77.3	175.9	145.8
Petrochemical & Refined Products Services:				
Sales of other petroleum and related products	871.7	413.3	1,804.3	674.8
Midstream services	130.9	134.2	259.8	267.3
Total	1,002.6	547.5	2,064.1	942.1
Total consolidated revenues	$ 7,543.4	$ 5,434.3	$ 16,087.9	$ 10,321.2

Comparison of Three Months Ended June 30, 2010 with Three Months Ended June 30, 2009

Revenues for the second quarter of 2010 were $7.54 billion compared to $5.43 billion for the second quarter of 2009. The $2.11 billion quarter-to-quarter increase in consolidated revenues is primarily due to higher energy commodity prices and sales volumes during the second quarter of 2010 compared to the second quarter of 2009. These factors accounted for a $2.06 billion quarter-to-quarter increase in consolidated revenues associated with our NGL, natural gas, crude oil, petrochemical and refined products marketing activities. Collectively, the remainder of our consolidated revenues increased $52.3 million quarter-to-quarter due to various factors including contributions from recently acquired and constructed assets and an increase in volumes and/or fees benefiting certain assets across all of our business segments.

Operating costs and expenses were $6.97 billion for the second quarter of 2010 compared to $5.02 billion for the second quarter of 2009, a $1.95 billion quarter-to-quarter increase. The cost of sales of our marketing activities increased $1.82 billion quarter-to-quarter primarily due to higher energy commodity prices and sales volumes. Likewise, the operating costs and expenses of our natural gas processing plants increased $137.3 million quarter-to-quarter primarily due to higher plant thermal reduction ("PTR") costs attributable to an increase in natural gas prices and processing volumes. Consolidated operating costs and expenses for the second quarter of 2009 include $68.4 million of expenses related to the forfeiture of our interest in the Texas Offshore Port System ("TOPS"). Collectively, the remainder of our consolidated operating costs and expenses increased $59.9 million quarter-to-quarter reflecting an increase in expenses for fuel costs, employee compensation and depreciation. General and administrative costs decreased $8.2 million quarter-to-quarter primarily due to expenses we incurred during the second quarter of 2009 in connection with the TEPPCO Merger that was completed in October 2009.

Changes in our revenues and operating costs and expenses quarter-to-quarter are explained in part by changes in energy commodity prices. The weighted-average indicative market price for NGLs was $1.11 per gallon during the second quarter of 2010 versus $0.76 per gallon during the second quarter of 2009 – a 46% quarter-to-quarter increase. Our determination of the weighted-average indicative market price for NGLs is based on U.S. Gulf Coast prices for such products at Mont Belvieu, Texas, which is the primary industry hub for domestic NGL production. The market price of natural gas (as measured at Henry Hub in Louisiana) averaged $4.09 per MMBtu during the second quarter of 2010 versus $3.51 per MMBtu during the second quarter of 2009. The market price of crude oil (as measured on the NYMEX) averaged $78.03 per barrel during the second quarter of 2010 compared to $59.79 per barrel during the second quarter of 2009 – a 31% quarter-to-quarter increase. See "Selected Price and Volumetric Data" included within this Item 2 for additional historical energy commodity pricing information.

Equity in income of our unconsolidated affiliates was $16.7 million for the second quarter of 2010 compared to $9.6 million for the second quarter of 2009, a $7.1 million quarter-to-quarter increase. Equity in income from our investments in Poseidon Oil Pipeline Company, L.L.C. ("Poseidon") and Cameron Highway Oil Pipeline Company ("Cameron Highway") increased $3.1 million quarter-to-quarter primarily due to higher crude oil transportation volumes. Equity in income from the Marco Polo platform, which is owned through our investment in Deepwater Gateway, L.L.C., increased $1.4 million quarter-to-quarter primarily due to higher crude oil processing volumes. Collectively, equity in income of our other investments increased $2.6 million quarter-to-quarter largely due to improved results from our investments in south Louisiana and Centennial Pipeline LLC ("Centennial").

Operating income for the second quarter of 2010 was $548.0 million compared to $373.3 million for the second quarter of 2009. Collectively, the aforementioned changes in revenues, costs and expenses and equity in income of unconsolidated affiliates resulted in the $174.7 million quarter-to-quarter increase in operating income.

Interest expense increased to $168.6 million for the second quarter of 2010 from $158.5 million for the second quarter of 2009. The $10.1 million quarter-to-quarter increase in interest expense is primarily due to higher average interest rates during the second quarter of 2010 compared to the second quarter of 2009. Average debt principal outstanding decreased to $11.95 billion during the second quarter of 2010 from $12.04 billion during the second quarter of 2009 reflecting lower average balances outstanding under revolving credit facilities. Provision for income taxes increased $3.4 million quarter-to-quarter.

As a result of items noted in the previous paragraphs, our consolidated net income increased $160.8 million quarter-to-quarter to $373.3 million for the second quarter of 2010 compared to $212.5 million for the second quarter of 2009. Net income attributable to noncontrolling interests was $16.1 million for the second quarter of 2010 compared to $25.9 million for the second quarter of 2009.

Noncontrolling interest for the second quarter of 2009 reflects $12.3 million of net income attributable to the former owners of TEPPCO. Net income attributable to Enterprise Products Partners increased $170.6 million quarter-to-quarter to $357.2 million for the second quarter of 2010 compared to $186.6 million for the second quarter of 2009.

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 $441.0 million for the second quarter of 2010 compared to $363.8 million for the second quarter of 2009, a $77.2 million quarter-to-quarter increase.

Gross operating margin from our natural gas processing and related NGL marketing business was $267.9 million for the second quarter of 2010 compared to $219.4 million for the second quarter of 2009, a $48.5 million quarter-to-quarter increase. Equity NGL production increased to 125 MBPD during the second quarter of 2010 from 118 MBPD during the second quarter of 2009. Fee-based natural gas processing volumes were 2,985 MMcf/d for the second quarter of 2010 compared to 2,714 MMcf/d for the second quarter of 2009. Our NGL marketing activities contributed $25.6 million of the quarter-to-quarter increase in gross operating margin primarily due to increased sales volumes and margins. During the second quarter of 2010, our NGL marketing activities benefited from a strong propane export market, isomerization demand and regional basis differentials. Collectively, gross operating margin from the remainder of these business activities increased $22.9 million quarter-to-quarter primarily due to increased equity NGL production and processing margins at our Rocky Mountain natural gas processing plants.

Gross operating margin from our NGL pipelines and related storage business was $138.9 million for the second quarter of 2010 compared to $106.4 million for the second quarter of 2009, a $32.5 million quarter-to-quarter increase. Total NGL transportation volumes increased to 2,194 MBPD during the second quarter of 2010 from 1,993 MBPD during the second quarter of 2009. Collectively, gross operating margin from our Dixie pipeline and pipelines in south Louisiana increased $17.0 million quarter-to-quarter primarily due to higher transportation volumes and average fees. Gross operating margin increased $7.6 million quarter-to-quarter due to increased utilization of our NGL import/export terminal on the Houston Ship Channel and related pipeline. Collectively, gross operating margin from the remainder of these business activities increased $7.9 million quarter-to-quarter primarily due to improved results from our NGL storage and terminal facilities, increased pipeline transportation volumes and contributions from our Rio Grande pipeline, which we acquired in the fourth quarter of 2009.

Gross operating margin from our NGL fractionation business was $34.2 million for the second quarter of 2010 compared to $38.0 million for the second quarter of 2009. The $3.8 million quarter-to-quarter decrease was primarily due to lower revenues from our Norco fractionator, which had benefited from higher realized NGL sales prices as a result of hedging activities during the second quarter of 2009. Fractionation volumes were 463 MBPD during the second quarter of 2010 compared to 459 MBPD during the second quarter of 2009. A quarter-to-quarter increase in volumes from our Norco and Promix NGL fractionators was largely offset by lower volumes from our south Texas fractionators during the second quarter of 2010. Our Shoup NGL fractionator in south Texas experienced scheduled downtime in June 2010 to complete construction activities that increased the fractionation capacity of this facility.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $106.9 million for the second quarter of 2010 compared to $121.2 million for the second quarter of 2009, a $14.3 million quarter-to-quarter decrease. Our onshore natural gas transportation volumes were 11,418 BBtus/d during the second quarter of 2010 compared to 10,672 BBtus/d during the second quarter of 2009.

Gross operating margin from our onshore natural gas pipeline and related natural gas marketing business was $95.4 million for the second quarter of 2010 compared to $108.8 million for the second quarter of 2009, a $13.4 million quarter-to-quarter decrease. Gross operating margin from our natural gas marketing activities decreased $25.3 million quarter-to-quarter. Results for natural gas marketing include

$11.6 million of non-cash, mark-to-market losses in the second quarter of 2010 associated with financial transactions for sales of natural gas in future periods. We expect substantially all of these non-cash, mark-to-market losses to be reversed in future periods upon settlement of the financial transactions and physical delivery of the natural gas. In comparison, results for the second quarter of 2009 included $5.8 million of non-cash, mark-to-market gains associated with financial transactions for sales of natural gas in future periods. Lastly, construction delays associated with our Trinity River Lateral (a 40-mile natural gas pipeline serving the Barnett shale basin) have resulted in a loss of approximately $3.0 million per month during the second quarter of 2010 for transportation capacity charges on a downstream pipeline incurred by our natural gas marketing business. We expect that these transportation capacity charges will be offset by the benefits of natural gas volumes originating on the Trinity River Lateral, which commenced operations in July 2010.

Gross operating margin from our Texas Intrastate System increased $8.2 million quarter-to-quarter primarily due to higher firm capacity reservation fee revenues during the second quarter of 2010 compared to the second quarter of 2009. The Sherman Extension of our Texas Intrastate System began earning firm capacity reservation fees during August 2009. Gross operating margin from our natural gas gathering and treating facilities in the Piceance Basin increased $4.0 million quarter-to-quarter due to higher volumes. In addition, the second quarter of 2010 includes $7.0 million of gross operating margin from natural gas pipeline systems we acquired during the quarter. Collectively, gross operating margin from the remainder of our natural gas pipeline businesses decreased $7.3 million quarter-to-quarter primarily due to lower gathering volumes on our Val Verde, Jonah and San Juan Gathering Systems.

Gross operating margin from our natural gas storage business was $11.5 million for the second quarter of 2010 compared to $12.4 million for the second quarter of 2009. The $0.9 million quarter-to-quarter decrease in gross operating margin is primarily due to measurement losses recorded during the second quarter of 2010 at our Hattiesburg underground natural gas storage facility.

Onshore Crude Oil Pipelines & Services. Gross operating margin from this business segment was $25.9 million for the second quarter of 2010 compared to $42.1 million for the second quarter of 2009. The $16.2 million quarter-to-quarter decrease in gross operating margin is primarily due to lower sales margins associated with our crude oil marketing activities. Sales margins were higher during the second quarter of 2009 due in part to higher earnings associated with the settlement of forward crude oil sales transactions. The quarter-to-quarter decrease in sales margins is also reflective of a competitive crude oil marketing environment and higher transportation costs during the second quarter of 2010 relative to the second quarter of 2009. Total onshore crude oil transportation volumes decreased to 678 MBPD during the second quarter of 2010 compared to 750 MBPD during the second quarter of 2009 primarily due to lower short-haul volumes on the Seaway crude oil pipeline system.

Offshore Pipelines & Services. Gross operating margin from this business segment was $82.8 million for the second quarter of 2010 compared to a loss of $1.1 million for the second quarter of 2009, an $83.9 million quarter-to-quarter increase. Results for the second quarter of 2010 include $9.5 million of gains relating to proceeds from insurance claims. Results for the second quarter of 2009 include $68.4 million of expenses related to the forfeiture of our interest in TOPS. The following paragraphs provide a discussion of segment results excluding insurance proceeds.

Gross operating margin from our offshore crude oil pipeline business was $25.9 million for the second quarter of 2010 compared to a loss of $54.1 million for the second quarter of 2009. Excluding charges related to TOPS, gross operating margin from our offshore crude oil pipelines increased $11.6 million quarter-to-quarter due to higher transportation volumes. Total offshore crude oil transportation volumes were 322 MBPD during the second quarter of 2010 versus 244 MBPD during the second quarter of 2009. Certain of our offshore crude oil pipelines were either in limited service or out of service during the second quarter of 2009 due to volume disruptions caused by the effects of Hurricanes Gustav and Ike. In general, these pipelines returned to full service during the third quarter of 2009.

Gross operating margin from our offshore natural gas pipeline business was $15.2 million for the second quarter of 2010 compared to $16.8 million for the second quarter of 2009, a $1.6 million quarter-to-quarter decrease. Results for the second quarter of 2010 include a $4.2 million increase in revenues attributable to a tariff rate case settlement on our High Island Offshore System. Collectively, gross operating margin from our offshore natural gas pipelines decreased $5.8 million quarter-to-quarter primarily due to lower transportation volumes on our Independence Trail pipeline. Total offshore natural gas transportation volumes were 1,312 BBtus/d during the second quarter of 2010 versus 1,460 BBtus/d during the second quarter of 2009.

Gross operating margin from our offshore platform services business was $32.2 million for the second quarter of 2010 compared to $36.2 million for the second quarter of 2009. Our net platform natural gas processing volumes were 568 MMcf/d during the second quarter of 2010 compared to 753 MMcf/d during the second quarter of 2009. The $4.0 million quarter-to-quarter decrease in gross operating margin is primarily due to lower natural gas processing volumes at our Independence Hub platform.

Volumes on our Independence Hub platform and Independence Trail pipeline experienced a quarter-to-quarter decrease as the result of production declines due to natural depletion and a production well watering out during the second quarter of 2010. In general, natural gas well workover activities have been delayed as the result of uncertainty regarding the federal offshore deepwater drilling moratorium.

Petrochemical & Refined Products Services. Gross operating margin from this business segment increased $62.0 million quarter-to-quarter to $158.1 million for the second quarter of 2010 from $96.1 million for the second quarter of 2009.

Gross operating margin from propylene fractionation and related activities was $67.6 million for the second quarter of 2010 compared to $22.6 million for the second quarter of 2009. The $45.0 million quarter-to-quarter increase in gross operating margin is primarily due to higher propylene fractionation volumes and sales margins. Propylene fractionation volumes increased to 79 MBPD during the second quarter of 2010 from 67 MBPD during the second quarter of 2009. Propylene sales margins were higher quarter-to-quarter as a result of improved product demand and lower propylene production from petrochemical crackers during the second quarter of 2010 relative to the second quarter of 2009.

Gross operating margin from octane enhancement was $10.9 million for the second quarter of 2010 compared to $6.9 million for the second quarter of 2009. The $4.0 million quarter-to-quarter increase in gross operating margin is primarily due to higher margins from sales of motor gasoline additives into export markets and revenues from by-product sales. Octane enhancement production volumes were 13 MBPD during the second quarter of 2010 compared to 10 MBPD during the second quarter of 2009. Gross operating margin from butane isomerization was $26.2 million for the second quarter of 2010 compared to $19.1 million for the second quarter of 2009. The $7.1 million quarter-to-quarter increase in gross operating margin is primarily due to higher commodity prices resulting in increased revenues from the sale of production by-products.

Gross operating margin from refined products pipelines and related activities was $30.9 million for the second quarter of 2010 compared to $30.3 million for the second quarter of 2009. The $0.6 million quarter-to-quarter increase in gross operating margin is primarily attributable to our Port Arthur, Texas refined products terminal, which we completed and placed in full commercial service during June 2010. Pipeline transportation volumes for the refined products business were 642 MBPD during the second quarter of 2010 compared to 669 MBPD during the second quarter of 2009.

Gross operating margin from marine transportation and other services was $22.5 million for the second quarter of 2010 compared to $17.2 million for the second quarter of 2009. The $5.3 million quarter-to-quarter increase in gross operating margin is primarily due to the expansion of our fleet of marine vessels (i.e., our acquisition and construction of marine vessels) and lower fleet repair expenses during the second quarter of 2010 relative to the second quarter of 2009.

Comparison of Six Months Ended June 30, 2010 with Six Months Ended June 30, 2009

Revenues for the first six months of 2010 were $16.09 billion compared to $10.32 billion for the first six months of 2009. The $5.77 billion period-to-period increase in consolidated revenues is primarily due to higher energy commodity prices and sales volumes during the first six months of 2010 compared to the first six months of 2009. These factors accounted for a $5.68 billion period-to-period increase in consolidated revenues associated with our NGL, natural gas, crude oil, petrochemical and refined products marketing activities. Collectively, the remainder of our consolidated revenues increased $84.8 million period-to-period due to various factors including additional revenues from recently acquired and constructed assets and an increase in volumes and/or fees benefiting certain assets across all of our business segments.

Operating costs and expenses were $14.95 billion for the first six months of 2010 compared to $9.40 billion for the first six months of 2009, a $5.55 billion period-to-period increase. The cost of sales of our marketing activities increased $5.07 billion period-to-period primarily due to higher energy commodity prices and sales volumes. Likewise, the operating costs and expenses of our natural gas processing plants increased $401.6 million period-to-period primarily due to higher PTR costs attributable to an increase in natural gas prices and processing volumes. Consolidated operating costs and expenses for the first six months of 2009 include $68.4 million of expenses related to the forfeiture of our interest in TOPS. Collectively, the remainder of our consolidated operating costs and expenses increased $145.0 million period-to-period reflecting an increase in expenses for fuel costs, maintenance, employee compensation and depreciation. General and administrative costs decreased $5.5 million period-to-period primarily due to expenses we incurred during the first six months of 2009 in connection with the TEPPCO Merger.

Changes in our revenues and operating costs and expenses period-to-period are explained in part by changes in energy commodity prices. The weighted-average indicative market price for NGLs was $1.17 per gallon during the first six months of 2010 versus $0.71 per gallon during the first six months of 2009 – a 65% period-to-period increase. The Henry Hub market price of natural gas averaged $4.70 per MMBtu during the first six months of 2010 versus $4.21 per MMBtu during the first six months of 2009. The NYMEX crude oil market price averaged $78.37 per barrel during the first six months of 2010 compared to $51.55 per barrel during the first six months of 2009 – a 52% period-to-period increase.

Equity in income of our unconsolidated affiliates was $32.7 million for the first six months of 2010 compared to $17.0 million for the first six months of 2009, a $15.7 million period-to-period increase. Equity in income from our investments in Cameron Highway and Poseidon collectively increased $9.4 million period-to-period primarily due to higher crude oil transportation volumes. Collectively, equity in income of our other investments increased $6.3 million period-to-period largely due to improved results from our investments in south Louisiana and Centennial.

Operating income for the first six months of 2010 was $1.10 billion compared to $856.1 million for the first six months of 2009. Collectively, the changes in revenues, costs and expenses and equity in income of unconsolidated affiliates described above resulted in the $242.9 million period-to-period increase in operating income.

Interest expense increased to $317.2 million for the first six months of 2010 from $311.0 million for the first six months of 2009. The $6.2 million period-to-period increase in interest expense is primarily due to higher average interest rates during the first six months of 2010 relative to the first six months of 2009. Average debt principal outstanding decreased to $11.63 billion during the first six months of 2010 from $11.88 billion during the first six months of 2009 reflecting lower average balances outstanding under revolving credit facilities.

Provision for income taxes decreased $3.9 million period-to-period primarily due to a one-time charge associated with taxable gains arising from Dixie Pipeline Company’s sale of certain assets during the first quarter of 2009.

As a result of items noted in the previous paragraphs, our consolidated net income increased $239.1 million period-to-period to $767.1 million for the first six months of 2010 compared to $528.0 million for the first six months of 2009. Net income attributable to noncontrolling interests was $32.1 million for the first six months of 2010 compared to $116.1 million for the first six months of 2009. Noncontrolling interest for the first six months of 2009 reflects $90.6 million of net income attributable to the former owners of TEPPCO. Net income attributable to Enterprise Products Partners increased $323.1 million period-to-period to $735.0 million for the first six months of 2010 compared to $411.9 million for the first six months of 2009.

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 $878.3 million for the first six months of 2010 compared to $714.7 million for the first six months of 2009, a $163.6 million period-to-period increase.

Gross operating margin from our natural gas processing and related NGL marketing business was $527.6 million for the first six months of 2010 compared to $414.0 million for the first six months of 2009, a $113.6 million period-to-period increase. Equity NGL production increased to 124 MBPD during the first six months of 2010 from 116 MBPD during the first six months of 2009. Our Rocky Mountain natural gas processing plants contributed $48.8 million of the period-to-period increase in gross operating margin primarily due to increased equity NGL production. We completed the Phase II expansion of our Meeker facility during March 2009. Gross operating margin from our NGL marketing activities increased $45.6 million period-to-period primarily due to higher sales volumes and margins. Collectively, gross operating margin from the remainder of these business activities increased $19.2 million period-to-period primarily due to higher natural gas processing margins in Louisiana and Texas.

Gross operating margin from our NGL pipelines and related storage business was $289.0 million for the first six months of 2010 compared to $232.8 million for the first six months of 2009, a $56.2 million period-to-period increase. Total NGL transportation volumes increased to 2,217 MBPD during the first six months of 2010 from 2,057 MBPD during the first six months of 2009. Collectively, gross operating margin from our Dixie pipeline and pipelines in south Louisiana increased $26.2 million period-to-period primarily due to higher transportation volumes and average fees. Gross operating margin increased $9.2 million period-to-period due to increased utilization of our NGL import/export terminal on the Houston Ship Channel and related pipeline. Gross operating margin from our Mont Belvieu storage facility increased $5.6 million period-to-period primarily due to increased storage volumes and fees. Collectively, gross operating margin from the remainder of these business activities increased $15.2 million period-to-period primarily due to improved results from our NGL storage and terminal facilities, increased pipeline transportation volumes, higher average fees on certain of our NGL pipelines and contributions from our Rio Grande pipeline, which we acquired in the fourth quarter of 2009.

Gross operating margin from our NGL fractionation business was $61.7 million for the first six months of 2010 compared to $67.9 million for the first six months of 2009. The $6.2 million period-to-period decrease in gross operating margin is primarily attributable to our Norco fractionator, which benefited from higher realized NGL sales prices due to hedging activities and recorded operating gains during the first six months of 2009. Fractionation volumes were 468 MBPD during the first six months of 2010 compared to 450 MBPD during the first six months of 2009.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $237.2 million for the first six months of 2010 compared to $283.1 million for the first six months of 2009, a $45.9 million period-to-period decrease. Our onshore natural gas transportation volumes were 11,300 BBtus/d during the first six months of 2010 compared to 10,506 BBtus/d during the first six months of 2009.

Gross operating margin from our onshore natural gas pipeline and related natural gas marketing business was $211.4 million for the first six months of 2010 compared to $257.7 million for the first six months of 2009, a $46.3 million period-to-period decrease. Gross operating margin from our natural gas marketing activities decreased $68.1 million period-to-period primarily due to lower sales margins and higher transportation and storage expenses. Natural gas basis differentials in Texas (specifically, the difference in natural gas prices between markets in west Texas and east Texas) were significantly lower during the first six months of 2010 relative to the first six months of 2009. The period-to-period decrease in basis differentials resulted in lower natural gas sales margins associated with our marketing activities and lower pipeline throughput volumes during the first six months of 2010. Also, construction delays associated with the completion of our Trinity River Lateral have resulted in a period-to-period decrease in gross operating margin of approximately $18.0 million as a result of charges for underutilized transportation capacity on a downstream pipeline incurred by our natural gas marketing business.

Gross operating margin from our Texas Intrastate System increased $10.3 million period-to-period. A $29.4 million period-to-period increase in firm capacity reservation fee revenues primarily on the Sherman Extension of our Texas Intrastate System was partially offset by the effects of lower throughput volumes on other segments of the Texas Intrastate System. Gross operating margin from our natural gas gathering and treating facilities in the Piceance Basin increased $8.9 million period-to-period due to higher volumes. Our Central Treating Facility in the Piceance Basin was placed into service during March 2009. In addition, the first six months of 2010 includes $7.0 million of gross operating margin earned by natural gas pipeline systems we acquired during the second quarter of 2010. Collectively, gross operating margin from the remainder of our natural gas pipeline businesses decreased $4.4 million period-to-period primarily due to lower gathering volumes on our Val Verde and Jonah Gathering Systems.

Gross operating margin from our natural gas storage business was $25.8 million for the first six months of 2010 compared to $25.4 million for the first six months of 2009. The $0.4 million period-to-period increase in gross operating margin is primarily due to improved results at our Petal gas storage facility and higher firm storage reservation fees at our Wilson gas storage facility.

Onshore Crude Oil Pipelines & Services. Gross operating margin from this business segment was $52.6 million for the first six months of 2010 compared to $92.6 million for the first six months of 2009. Total onshore crude oil transportation volumes decreased to 675 MBPD during the first six months of 2010 compared to 698 MBPD during the first six months of 2009. The $40.0 million period-to-period decrease in gross operating margin is primarily due to lower sales margins associated with our crude oil marketing activities as a result of the competitive crude oil marketing environment. Lower sales margins reflect a period-to-period decrease in basis differentials. Basis differentials represent the difference in crude oil prices between two locations or price differences for various qualities of crude oil (e.g., "sweet" crude versus "sour" crude). Higher transportation costs during the first six months of 2010 relative to the first six months of 2009 also had a negative impact on crude oil sales margins. Lastly, earnings associated with the settlement of forward crude oil sales transactions were greater during the first six months of 2009 compared to the first six months of 2010.

Offshore Pipelines & Services. Gross operating margin from this business segment was $163.9 million for the first six months of 2010 compared to $60.2 million for the first six months of 2009, a $103.7 million period-to-period increase. Results for the first six months of 2010 include $18.2 million of gains related to proceeds from insurance claims. Results for the first six months of 2009 include $68.4 million of expenses related to the forfeiture of our interest in TOPS. The following paragraphs provide a discussion of segment results excluding insurance proceeds.

Gross operating margin from our offshore crude oil pipeline business was $51.2 million for the first six months of 2010 compared to a loss of $49.0 million for the first six months of 2009. Excluding charges related to TOPS, gross operating margin from our offshore crude oil pipelines increased $31.8 million period-to-period. Gross operating margin from our Shenzi crude oil pipeline, which commenced operations in April 2009, increased $13.1 million period-to-period. Collectively, gross operating margin from the remainder of our crude oil pipelines increased $18.7 million period-to-period due to increased transportation volumes. Certain of these pipelines were either in limited service or out of service during the first six months of 2009 due to volume disruptions caused by the effects of Hurricanes Gustav and Ike.

Total offshore crude oil transportation volumes were 338 MBPD during the first six months of 2010 compared to 219 MBPD during the first six months of 2009.

Gross operating margin from our offshore natural gas pipeline business was $27.4 million for the first six months of 2010 compared to $34.5 million for the first six months of 2009. The $7.1 million period-to-period decrease in gross operating margin is primarily due to lower transportation volumes on our Independence Trail pipeline. Natural gas transportation volumes on our Independence Trail pipeline decreased to 676 BBtus/d during the first six months of 2010 from 906 BBtus/d during the first six months of 2009. Total offshore natural gas transportation volumes were 1,359 BBtus/d during the first six months of 2010 versus 1,501 BBtus/d during the first six months of 2009.

Gross operating margin from our offshore platform services business was $67.1 million for the first six months of 2010 compared to $74.7 million for the first six months of 2009. Our net platform natural gas processing volumes were 600 MMcf/d during the first six months of 2010 compared to 765 MMcf/d during the first six months of 2009. The $7.6 million period-to-period decrease in gross operating margin is primarily due to lower natural gas processing volumes at our Independence Hub platform. Volumes on our Independence Hub platform and Independence Trail pipeline experienced a period-to-period decrease primarily as the result of (i) production declines due to natural depletion and a production well watering out during 2010 and (ii) downtime during 2010 for construction of a deck extension and maintenance.

Petrochemical & Refined Products Services. Gross operating margin from this business segment increased $92.5 million period-to-period to $278.1 million for the first six months of 2010 from $185.6 million for the first six months of 2009.

Gross operating margin from propylene fractionation and related activities was $110.7 million for the first six months of 2010 compared to $45.6 million for the first six months of 2009. The $65.1 million period-to-period increase in gross operating margin is primarily due to higher propylene fractionation volumes and sales margins. Propylene fractionation volumes increased to 79 MBPD during the first six months of 2010 from 67 MBPD during the first six months of 2009.

Gross operating margin from octane enhancement was $15.0 million for the first six months of 2010 compared to a loss of $1.2 million for the first six months of 2009. The $16.2 million period-to-period increase in gross operating margin is primarily due to higher margins from sales of motor gasoline additives into export markets and revenues from by-product sales. Octane enhancement production volumes were 12 MBPD during the first six months of 2010 compared to 7 MBPD during the first six months of 2009.

Gross operating margin from butane isomerization was $41.0 million for the first six months of 2010 compared to $34.0 million for the first six months of 2009, a $7.0 million period-to-period increase. Higher commodity prices resulting in increased revenues from the sale of production by-products more than offset the effect of lower isomerization volumes. Butane isomerization volumes decreased to 86 MBPD during the first six months of 2010 from 95 MBPD during the first six months of 2009.

Gross operating margin from refined products pipelines and related activities was $79.8 million for the first six months of 2010 compared to $75.8 million for the first six months of 2009. The $4.0 million period-to-period increase in gross operating margin is primarily due to an increase in refined products marketing activities, higher average pipeline transportation fees and earnings from our Port Arthur, Texas refined products terminal, which we completed and placed in full commercial service during June 2010. Pipeline transportation volumes for the refined products business were 662 MBPD during the first six months of 2010 compared to 696 MBPD during the first six months of 2009.

Gross operating margin from marine transportation and other services was $31.6 million for the first six months of 2010 compared to $31.4 million for the first six months of 2009, a $0.2 million period-to-period increase. An increase in gross operating margin attributable to earnings from recently acquired and constructed marine vessels was partially offset by higher operating expenses during the first six months of 2010 as compared to the first six months of 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 combinations 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, 2010, we had $494.5 million of unrestricted cash on hand resulting primarily from our equity and debt offerings in April and May 2010 (discussed below), partially offset by cash used to complete the State Line and Fairplay systems acquisitions and for other general partnership purposes. Also at June 30, 2010, we had approximately $1.83 billion of available credit under our revolving credit facilities, which includes the available borrowing capacity of our consolidated subsidiaries such as Duncan Energy Partners. We had approximately $12.63 billion in principal outstanding under consolidated debt agreements at June 30, 2010. In total, our consolidated liquidity at June 30, 2010 was approximately $2.32 billion.

Registration Statements

We may issue equity or debt securities to assist us in meeting our future liquidity and capital spending requirements. Duncan Energy Partners may do likewise in meeting its liquidity and capital spending requirements. In July 2010, we filed a new universal shelf registration statement with the U.S. Securities and Exchange Commission ("SEC") that allows us to issue an unlimited amount of debt and equity securities for general partnership purposes. No securities have been issued under this registration statement as of the filing of this quarterly report.

The following tables present information regarding equity and debt offerings made under our prior universal shelf registration statement from January 1, 2010 through June 30, 2010. Dollar amounts presented in the tables are in millions, except offering price amounts.

Underwritten Equity Offering	Number of Common Units Issued	Offering Price	Total Net Cash Proceeds
January 2010 underwritten offering (1)	10,925,000	$ 32.42	$ 350.3
April 2010 underwritten offering (2)	13,800,000	$ 35.55	484.6
Total	24,725,000		$ 834.9

(1) Net cash proceeds from this equity offering were used to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes.
(2) Net cash proceeds from this equity offering were used to pay a portion of the purchase price of the State Line and Fairplay natural gas gathering systems and for general partnership purposes.

Note Series	Issued	Principal Amount
Senior Notes X	May 2010	$ 400.0
Senior Notes Y	May 2010	1,000.0
Senior Notes Z	May 2010	600.0
Total (1)		$ 2,000.0

(1) Net proceeds from the issuance of these senior notes were used (i) to repay outstanding amounts due upon the maturity of EPO's Senior Notes K, (ii) to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and (iii) for general partnership purposes.

At June 30, 2010, Duncan Energy Partners could issue approximately $856.4 million of additional equity or debt securities under its universal shelf registration statement.

We have filed registration statements with the SEC authorizing the issuance of up to an aggregate of 70,000,000 common units in connection with our distribution reinvestment plan ("DRIP"). The DRIP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of common units they own by reinvesting the quarterly cash distributions they would otherwise receive into the purchase of additional common units of our partnership. During the six months ended June 30, 2010, we issued 4,768,959 common units in connection with our DRIP, which generated proceeds of $148.8 million from plan participants. Affiliates of EPCO reinvested $119.5 million in connection with the DRIP during the six months ended June 30, 2010.

In addition, we have a registration statement on file related to our employee unit purchase plan, under which we can issue up to an aggregate of 1,200,000 common units. Under this plan, employees of EPCO can purchase our common units at a 10% discount through payroll deductions. During the six months ended June 30, 2010, we issued 105,295 common units to employees under this plan, which generated proceeds of $3.3 million.

For additional information regarding our public debt obligations and partnership equity amounts, see Notes 10 and 11, 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, 2010, EPO had a $50.0 million letter of credit outstanding related to its commodity derivative instruments and a $58.3 million letter of credit outstanding 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.

Credit Ratings

At August 1, 2010, the investment-grade credit ratings of EPO's senior unsecured debt securities were: Baa3, Moody's Investor Services ("Moody's"); BBB-, Fitch Ratings; and BBB-, Standard and Poor's. On April 30, 2010, Standard and Poor's reaffirmed its corporate credit rating of EPO, revised its outlook for our business from "stable" to "positive" and updated its business risk assessment from "satisfactory" to "strong." EPO's credit ratings reflect only the view of a rating agency and should not be interpreted as a recommendation to buy, sell or hold any of our securities. A credit rating can be revised upward or downward or withdrawn at any time by a rating agency if it determines that circumstances warrant such a change. A credit rating from one rating agency should be evaluated independently of credit ratings from any other rating agencies.

Based on the debt and equity characteristics of our $1.53 billion of junior subordinated notes (a type of hybrid security), the rating agencies assigned partial equity treatment to such notes. The ratings agencies use this treatment to adjust their credit metrics to gain a clearer economic view of the debt and equity components of our capitalization. Standard and Poor's assigns 50% equity treatment to the junior subordinated notes and Fitch Ratings assigns a 75% equity treatment. In July 2010, Moody's announced revisions to their classification system for hybrid securities. Moody's reduced the equity credit that it assigns to securities such as our junior subordinated notes from 50% to 25%. We do not believe this revision will affect our investment-grade Baa3 senior unsecured debt rating from Moody's.

A downgrade of EPO's credit ratings could result in our being required to post financial collateral in connection with our guaranty of Centennial's debt, which was $57.7 million at June 30, 2010. Furthermore, from time to time we may enter into contracts in connection with our commodity and interest rate hedging activities that may require the posting of financial collateral if EPO's credit ratings were to be downgraded below investment grade.

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 on Form 10-Q.

	For the Six Months Ended June 30,	
	2010	**2009**
Net cash flows provided by operating activities	$ 900.3	$ 635.0
Cash used in investing activities	1,891.8	887.3
Cash provided by financing activities	1,431.2	261.5

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

Comparison of Six Months Ended June 30, 2010 with Six Months Ended June 30, 2009

Operating Activities. The $265.3 million increase in net cash flows provided by operating activities was primarily due to the following:

- Net cash flows from consolidated operations (excluding distributions received from unconsolidated affiliates, cash payments for interest and cash payments for income taxes) increased $255.0 million period-to-period. The increase in operating cash flow is generally due to increased profitability (e.g., our gross operating margin increased $273.9 million period-to-period) and the timing of related cash receipts and disbursements.

- Distributions received from unconsolidated affiliates increased $25.3 million period-to-period primarily due to higher distributions received from Poseidon and Cameron Highway. In February 2010, we also began receiving distributions from Skelly-Belvieu Pipeline Company, L.L.C.

- Cash payments for interest increased approximately $33.7 million period-to-period primarily due to an increase in fixed-rate debt obligations period-to-period.

- Cash payments for income taxes decreased $18.7 million period-to-period primarily due to higher payments made during the six months ended June 30, 2009 for the Texas Margin Tax and a taxable gain arising from Dixie's sale of certain assets.

Investing Activities. The $1.0 billion increase in cash used for investing activities was primarily due to the following:

- Cash used for business combinations increased $1.15 billion period-to-period, primarily due to the May 2010 acquisition of the State Line and Fairplay natural gas gathering systems for approximately $1.2 billion.

- Capital spending for property, plant and equipment, net of contributions in aid of construction costs, decreased $85.8 million period-to-period. For additional information related to our capital spending program, see “Liquidity and Capital Resources – Capital Spending” included within this Item 2.

- Restricted cash decreased $33.2 million period-to-period due to a reduction in margin requirements related to our commodity hedging activities.

- Proceeds from asset sales and related transactions increased $23.5 million period-to-period.

Financing Activities. The $1.17 billion increase in cash provided by financing activities was primarily due to the following:

- Net borrowings under our consolidated debt agreements increased $803.0 million period-to-period. During the six months ended June 30, 2010 EPO issued $2.0 billion in senior notes (Senior Notes X, Y and Z) offset by (i) the maturity and repayment of its $500.0 million of Senior Notes K and its $54.0 million Pascagoula Mississippi Business Finance Corporation (“MBFC”) Loan and (ii) the temporary repayment of amounts borrowed under its Multi-Year Revolving Credit Facility. For additional information regarding our consolidated debt obligations see Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

- Cash distributions paid to our partners increased $266.7 million period-to-period due to increases in our common units outstanding and quarterly distribution rates.

- Cash distributions paid to noncontrolling interests decreased $174.0 million period-to-period primarily due to the cessation of TEPPCO’s cash distributions following the TEPPCO Merger in October 2009.

- Cash contributions from noncontrolling interests decreased $122.4 million period-to-period primarily due to Duncan Energy Partner’s equity offering in June 2009, which generated $123.2 million in proceeds.

- Net cash proceeds from the issuance of our common units increased $592.9 million period-to-period primarily due to our two underwritten equity offerings in January and April 2010 compared to our one underwritten equity offering in January 2009.

Capital Spending

An integral part of our business strategy involves expansion through business combinations, growth capital projects and investments in joint ventures. We believe that we are positioned to continue to grow our system of assets through the construction of new facilities and to capitalize on expected increases in natural gas and/or crude oil production from resource basins in the Rocky Mountains, Northeast and U.S. Gulf Coast regions, including the Barnett Shale, Haynesville Shale, Eagle Ford Shale and Marcellus Shale producing regions.

Management continues to analyze potential acquisitions, joint ventures and similar transactions with businesses that operate in complementary markets or geographic regions. In past years, major oil and gas companies have sold non-strategic assets in the midstream energy sector in which we operate. We believe this trend will continue, and expect independent oil and natural gas companies to consider similar divestitures.

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

	For the Six Months Ended June 30,	
	2010	2009
Capital spending for property, plant and equipment, net of contributions in aid of construction costs	$ 738.1	$ 823.9
Capital spending for business combinations	1,220.2	73.7
Capital spending for intangible assets	--	1.4
Capital spending for investments in unconsolidated affiliates	10.2	9.8
Total capital spending	$ 1,968.5	$ 908.8

Based on information currently available, we estimate our consolidated capital spending for the remainder of 2010 will be approximately $1.1 billion, which includes estimated expenditures of $1.0 billion for growth capital projects and acquisitions and $130.0 million for sustaining capital expenditures.

Our forecast of consolidated capital expenditures is based on our currently announced strategic operating and growth plans, which 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, 2010, we had approximately $719.4 million in purchase commitments outstanding that relate to our capital spending for property, plant and equipment. These commitments primarily relate to construction at our Mont Belvieu complex and our Barnett Shale, Haynesville Shale and Piceance Basin natural gas pipeline projects.

Pipeline Integrity Costs

Our NGL, crude oil, refined products, petrochemical and natural gas pipelines are subject to pipeline safety programs administered by the Department of Transportation. This federal agency has issued safety regulations containing requirements for the development of integrity management programs for hazardous liquid pipelines (which include NGL, crude oil, refined products and petrochemical pipelines) and natural gas pipelines. In general, these regulations require companies to assess the condition of their pipelines in certain 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,	
	2010	2009	2010	2009
Expensed	$ 10.0	$ 14.2	$ 19.4	$ 21.6
Capitalized	10.8	11.8	13.5	15.3
Total	$ 20.8	$ 26.0	$ 32.9	$ 36.9

We expect the costs of our pipeline integrity program, irrespective of whether such costs are capitalized or expensed, to approximate $60.1 million for the remainder of 2010.

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 2009 Form 10-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 litigation contingencies; and natural gas imbalances. These estimates are based on our current knowledge and understanding of the underlying facts and circumstances and may change as a result of actions we 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.

Other Items

Recent Accounting Developments

In November 2008, the SEC released a proposed roadmap regarding the potential use by U.S. issuers of financial statements prepared in accordance with International Financial Reporting Standards ("IFRS"). IFRS consist of accounting standards published by the International Accounting Standards Board ("IASB"), which is based in London, England. In February 2010, the SEC expressed its continuing support for a single set of high-quality globally accepted accounting standards and established a general work plan that sets forth areas and factors the SEC will consider before requiring domestic public companies to transition to IFRS. Currently, the Financial Accounting Standards Board (or "FASB," based in Norwalk, Connecticut) and the IASB are working both individually and jointly on a number of accounting standard convergence projects that, if finalized in 2011, would bring about a significant shift in the accounting and financial reporting landscape. These projects include a broad range of topics such as financial statement presentation, accounting for leases, revenue recognition, financial instruments, consolidations and fair value measurements.

The SEC will make a determination in 2011 regarding the mandatory adoption of IFRS with the expectation that any decision to adopt IFRS would allow U.S. issuers four to five years to transition from current U.S. GAAP. We continue to monitor developments in the potential implementation of IFRS and the ongoing convergence projects of the FASB and IASB. We will evaluate the impact that any definitive accounting guidance may have on our financial statements once this information is finalized by the appropriate standard setting organizations, including the SEC.

Insurance Matters

We participate as a named insured in EPCO's insurance program, which provides us with property damage, business interruption and other coverages, the scope and amounts of which we believe are customary and prudent for the nature and extent of our operations. We recently completed our annual insurance policy renewal process. For additional information regarding insurance matters, see Note 16 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

We expect to recognize a gain of approximately $70 million during the third quarter of 2010 related to cash proceeds from insurance recoveries associated with an offshore natural gas pipeline system and an offshore platform. The expected proceeds approximate the negotiated value of the covered assets, which were damaged by windstorms or other events. The expected gain represents the excess of the insurance proceeds over the carrying value of the related assets.

Contractual Obligations

With the exception of (i) routine fluctuations in the balance of our consolidated revolving credit facilities, (ii) the issuance of Senior Notes X, Y and Z in May 2010 and (iii) the repayments of the Pascagoula MBFC Loan in March 2010 and Senior Notes K in June 2010, there have been no significant changes in our consolidated debt obligations since those reported in our 2009 Form 10-K. For additional information regarding our consolidated debt obligations, see Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Off-Balance Sheet Arrangements

There have been no significant changes with regards to our off-balance sheet arrangements since those reported in our 2009 Form 10-K.

Regulatory Matters

Certain scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" and including carbon dioxide (which is a component of, and a product of combustion of, natural gas) and methane (which is a component of natural gas), may be contributing to global climate change and ocean acidification. On June 26, 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009 ("ACESA") which, if it were to become law, would establish an economy-wide cap-and-trade program intended to reduce the emissions of greenhouse gases by the United States and would require most significant domestic sources of greenhouse gas emissions to obtain greenhouse gas emission "allowances" corresponding to their annual emissions of greenhouse gases. The U.S. Senate has also begun consideration of various legislative proposals for controlling and reducing emissions of greenhouse gases in the United States. In addition, on December 7, 2009, the U.S. Environmental Protection Agency ("EPA") announced its finding that emissions of greenhouse gases from motor vehicles caused or contributed to climate change and presented an endangerment to human health and the environment. These findings by the EPA were the basis for motor vehicle greenhouse gas emissions standards promulgated on May 7, 2010, and may allow the agency to proceed with the adoption and implementation of additional regulations that would restrict emissions of greenhouse gases from industrial sources under existing provisions of the federal Clean Air Act. On May 13, 2010, the EPA issued a final rule setting forth a timetable for extension of its Prevention of Significant Deterioration regulatory program, applicable in certain circumstances to new and modified industrial source of air emissions, to include consideration of greenhouse gas emissions. The EPA has also received petitions requesting that the agency further expand regulation of greenhouse gas emissions from industrial sources, which, over time, may lead to additional requirements. On April 12, 2010, the EPA proposed new rules that would require the mandatory reporting of greenhouse gas emissions by pipeline operators and operators of natural gas processing and storage facilities. These rules supplement disclosures and reporting required by the EPA in its October 30, 2009 mandatory greenhouse gas reporting rule. Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases, or that establish new reporting requirements, would likely require us to incur increased operating costs, and may have an adverse effect on our financial position, results of operations and cash flows.

Related Party Transactions

For information regarding our related party transactions, see Note 13 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 non-GAAP measure of total segment gross operating margin to GAAP operating income and income before provision for income taxes for the periods indicated (dollars in millions):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
Total segment gross operating margin	$ 814.7	$ 622.1	$ 1,610.1	$ 1,336.2
Adjustments to reconcile total segment gross operating margin to operating income:				
Depreciation, amortization and accretion in operating costs and expenses	(227.0)	(200.5)	(439.4)	(396.9)
Non-cash asset impairment charges	--	(2.3)	(1.5)	(2.3)
Operating lease expenses paid by EPCO	(0.1)	(0.1)	(0.3)	(0.3)
Gains (losses) from asset sales and related transactions in operating costs and expenses	(1.7)	0.2	5.6	0.4
General and administrative costs	(37.9)	(46.1)	(75.5)	(81.0)
Operating income	548.0	373.3	1,099.0	856.1
Other expense, net	(168.2)	(157.7)	(316.7)	(309.0)
Income before provision for income taxes	$ 379.8	$ 215.6	$ 782.3	$ 547.1

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 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, options and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities. See Note 4 of the Notes to the 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,” included in our 2009 Form 10-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 (a sensitivity analysis) on the estimated fair value (“FV”) of our interest rate swap portfolios at the dates presented (dollars in millions):

Enterprise Products Partners (excluding Duncan Energy Partners)	**Resulting**	**Swap Fair Value at**	
Scenario	**Classification**	**June 30, 2010**	**July 20, 2010**
FV assuming no change in underlying interest rates	*Asset*	$ 59.9	$ 64.8
FV assuming 10% increase in underlying interest rates	*Asset*	56.5	61.9
FV assuming 10% decrease in underlying interest rates	*Asset*	63.3	67.8

Duncan Energy Partners Scenario	Resulting Classification	Swap Fair Value at June 30, 2010	July 20, 2010
FV assuming no change in underlying interest rates	*Liability*	$ (1.8)	$ (1.8)
FV assuming 10% increase in underlying interest rates	*Liability*	(1.8)	(1.8)
FV assuming 10% decrease in underlying interest rates	*Liability*	(1.8)	(1.8)

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

Scenario	Resulting Classification	Swap Fair Value at June 30, 2010	July 20, 2010
FV assuming no change in underlying interest rates	*Liability*	$ (56.6)	$ (56.4)
FV assuming 10% increase in underlying interest rates	*Liability*	(19.8)	(19.7)
FV assuming 10% decrease in underlying interest rates	*Liability*	(97.2)	(97.2)

Commodity Derivative Instruments

The prices of natural gas, NGLs, crude oil, refined products and certain petrochemical products are subject to fluctuations in response to changes in supply and demand, market conditions and a variety of additional factors that are beyond our control. We may use commodity derivative instruments such as physical forward agreements, futures contracts, fixed-for-float swaps, basis swaps and options contacts to mitigate such risks.

We assess the risk of our commodity derivative instrument portfolios using a sensitivity analysis model. The sensitivity analysis applied to these portfolios measures the potential income or loss (i.e., the change in fair value of the portfolio) based upon a hypothetical 10% movement in the underlying quoted market prices of the commodity derivative instruments outstanding at the date indicated within the following tables.

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, 2010	July 20, 2010
FV assuming no change in underlying commodity prices	*Liability*	$ (12.6)	$ (12.1)
FV assuming 10% increase in underlying commodity prices	*Liability*	(19.8)	(19.9)
FV assuming 10% decrease in underlying commodity prices	*Liability*	(5.4)	(4.3)

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

Scenario	Resulting Classification	Portfolio Fair Value at June 30, 2010	July 20, 2010
FV assuming no change in underlying commodity prices	*Asset*	$ 48.5	$ 42.8
FV assuming 10% increase in underlying commodity prices	*Liability*	(8.0)	(21.6)
FV assuming 10% decrease in underlying commodity prices	*Asset*	105.0	107.2

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

Scenario	Resulting Classification	Portfolio Fair Value at June 30, 2010	July 20, 2010
FV assuming no change in underlying commodity prices	*Asset*	$ 12.1	$ 9.5
FV assuming 10% increase in underlying commodity prices	*Liability*	(3.1)	(3.6)
FV assuming 10% decrease in underlying commodity prices	*Asset*	27.3	22.6

Our predominant hedging strategy is to hedge an amount of gross margin associated with our gas processing activities. We achieve this objective by using physical and financial instruments to lock in the purchase prices of natural gas consumed as PTR and the sales prices of the related NGL products. This program consists of:

- the forward sale of a portion of our expected equity NGL production at fixed prices through December 2010, which is achieved through the use of forward physical sales contracts and commodity derivative instruments and

- the purchase of commodity derivative instruments having a notional amount based on the volume of natural gas expected to be consumed as PTR in the production of such equity NGL production.

At June 30, 2010 and July 23, 2010, this program had hedged future estimated gross margins (before plant operating expenses) of $301.6 million on 11.0 MMBbls of forecasted NGL forward sales transactions and equivalent PTR volumes extending through December 2010. Our estimates of future gross margins are subject to various business risks, including unforeseen production outages or declines, counterparty risk, or similar events or developments that are outside of our control.

Foreign Currency Derivative Instruments

We are exposed to a nominal amount of 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 an exchange rate. At June 30, 2010, our foreign currency derivative instruments portfolio had a notional amount of $6.0 million Canadian. The fair market value of these derivative instruments was a liability of $0.1 million at June 30, 2010.

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 CEO (our principal executive officer) and our general partner's chief financial officer (our principal 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) during the second quarter of 2010, 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 regarding legal proceedings, see Part I, Item 1, Financial Statements, Note 15, “Commitments and Contingencies – Litigation,” of the Notes to Unaudited Condensed Consolidated Financial Statements included in this quarterly report, which is incorporated herein by reference.

Item 1A. *Risk Factors*.

Security holders and potential investors in our securities should carefully consider the risk factors set forth in our 2009 annual report on Form 10-K and below, in addition to other information in such annual report and in this quarterly report on Form 10-Q. 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.

The death of Dan L. Duncan represents the loss of a key member of our senior management team.

Although the remainder of our senior management team remains in place and succession planning regarding control of our general partner exists, we cannot predict at this time the effect of the loss of Mr. Duncan and cannot provide any assurances that his loss will not have any effect on our business, results of operations or cash flows.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays incurred by customers in the production of oil and natural gas, including from the developing shale plays. A decline in drilling of new wells and related servicing activities caused by these initiatives could adversely affect our financial position, results of operations and cash flows.

Proposals have been introduced in the U.S. Congress to regulate hydraulic fracturing operations and related injection of fracturing fluids and propping agents used in fracturing fluids by the oil and natural gas industry under the federal Safe Drinking Water Act (“SDWA”) and to require the disclosure of chemicals used in the hydraulic fracturing process under the SDWA, Emergency Planning and Community Right-to-Know Act (“EPCRA”), or other authority. Hydraulic fracturing is an important and commonly used process in the completion of unconventional oil and natural gas wells in shale, coalbed and tight sand formations. Sponsors of these bills, which are currently being considered in the legislative process, including in the House Energy and Commerce Committee and the Senate Environmental and Public Works Committee, have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies and otherwise cause adverse environmental impacts. The Chairman of the House Energy and Commerce Committee has initiated an investigation of the potential impacts of hydraulic fracturing, which has involved seeking information about fracturing activities and chemicals from certain companies in the oil and gas sector. In addition, in March 2010, the U.S. EPA announced its intention to conduct a comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on water quality and public health. Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of crude oil and natural gas, including from the developing shale plays, incurred by our customers or could make it more difficult to perform hydraulic fracturing. If these legislative and regulatory initiatives cause a material decrease in the drilling of new wells and related servicing activities, our profitability could be materially impacted.

The suspension of new drilling and permitting in the Gulf of Mexico, or any additional regulations that cause delays or deter new drilling, could have a material adverse effect on our financial position, results of operations and cash flows.

On April 20, 2010, the Deepwater Horizon drilling rig owned and operated by BP plc and others caught fire and sank in the Gulf of Mexico, resulting in an oil spill that has significantly impacted ecological resources in the Gulf of Mexico. As a result, on May 28, 2010, the U.S. Department of the Interior issued a six-month moratorium that halted drilling of uncompleted and new oil and gas wells (in water deeper than 500 feet) in the Gulf of Mexico with certain limited exceptions and halted consideration of drilling permits for deepwater wells. In addition to the moratorium, the Department of the Interior has also canceled or delayed offshore oil and gas lease sales off the Mid-Atlantic coast and in Alaska. The Department of Interior also has announced new safety and certification requirements which could alter, delay, or increase the cost of exploration and production activities.

On June 22, 2010, in a lawsuit challenging the May 28 moratorium, a federal district judge in Louisiana issued a preliminary injunction staying enforcement of the May 28 moratorium on the grounds that the federal government failed to justify the measure. On July 12, 2010, the Interior Secretary issued a suspension order that replaced and superseded the May 28 moratorium. The July 12 decision suspended (i) the drilling of wells using subsea blowout preventers ("BOPs") or surface BOPs on a floating facility and (ii) the approval of pending and future applications for permits to drill using subsea BOPs or surface BOPs on a floating facility. This new drilling suspension will apply until November 30, 2010, subject to modification. On July 9, 2010, a second lawsuit was filed in federal district court in Louisiana against the Interior Secretary alleging that the Secretary violated the OSCLA and the Administrative Procedure Act by issuing the May 28, 2010 moratorium, imposing new safety and certification requirements, and unreasonably delaying approval of applications for drilling on the Outer Continental Shelf. It is anticipated that this lawsuit will be amended to address the July 12, 2010 suspension decision.

Further, the Bureau of Ocean Energy Management, Regulation and Enforcement ("BOEM"), formerly the Minerals Management Service, which is charged with oversight of the United States' oil, natural gas and other minerals on the Outer Continental Shelf, is being reorganized under an Interior secretarial order, which may be reinforced through legislation. Accordingly, the prospects and timing of continued drilling in deepwater areas of the Gulf of Mexico and activities on the Outer Continental Shelf of the United States are evolving and uncertain. Such uncertainty may cause companies to redirect their deepwater drilling activities to other areas such as West Africa, the Caribbean or South America, which may further delay the resumption of drilling activity in the Gulf of Mexico. It is uncertain at this time whether and how oil and natural gas supplies from the Gulf of Mexico will be affected.

In addition to federal agency action and related litigation, numerous legislative proposals reacting to the Deepwater Horizon incident have been introduced in the U.S. Congress, some of which are moving through the legislative process. Bills that have received attention include measures to:

- modify or revoke liability limits and caps under the Oil Spill Liability Trust Fund, the Oil Pollution Act of 1990, and certain other statutes;
- revise federal liability regimes to include health effects, personal injuries, and other tort claims;
- mandate more stringent safety measures and inspections under the Oil Pollution Act and Outer Continental Shelf Lands Act;
- expand environmental reviews and lengthen review timelines;
- impose fees, increase taxes or remove tax exemptions;
- modify financial responsibility and insurance requirements for offshore energy activities; and
- require U.S. registration of oil rigs.

Some of these proposals are being actively advanced, although it is unclear whether and when Congress may pass legislation, particularly in light of impending Congressional elections and a crowded legislative calendar.

Given the scope and effect of the Deepwater Horizon incident to date, as well as statements made by the Interior Secretary, it is expected that additional regulations and agency reviews will be required prior to resuming drilling or permitting new wells, which may affect the cost and timing of oil and gas production in the Gulf of Mexico in the short to medium-term timeframe. A decline in, or failure to achieve anticipated volumes of, oil and natural gas supplies due to any of the foregoing factors may have a material adverse effect on our financial position, results of operations or cash flows.

The adoption and implementation of new statutory and regulatory requirements for derivative transactions could have an adverse impact on our ability to hedge risks associated with our business and increase the working capital requirements to conduct these activities.

The United States Congress has passed, and the President has signed into law, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Act"). The Act provides for new statutory and regulatory requirements for derivative transactions, including oil and gas hedging transactions. Certain transactions will be required to be cleared on exchanges, and cash collateral will be required for these transactions. The Act provides for a potential exception from these clearing and cash collateral requirements for commercial end-users and it includes a number of defined terms that will be used in determining how this exception applies to particular derivative transactions and to the parties to those transactions. The Act requires the Commodities Futures and Trading Commission (the "CFTC") to promulgate rules to define these terms in detail, but we do not know the definitions that the CFTC will actually promulgate or how these definitions will apply to us.

We enter into natural gas derivative contracts from time to time with respect to a portion of our expected natural gas processing and storage activities (including for the benefit of our customers or our purchases of natural gas held-for-sale to third parties) in connection with these products in order to hedge against commodity price uncertainty and enhance the predictability of cash flows from these activities. Depending on the rules and definitions adopted by the CFTC, we might in the future be required to provide cash collateral for our commodities hedging transactions. Posting of cash collateral could cause liquidity issues for us by reducing our ability to use our cash for capital expenditures or other partnership purposes. A requirement to post cash collateral could therefore significantly reduce our ability to execute strategic hedges to reduce commodity price uncertainty and thus protect cash flows. We are at risk unless and until the CFTC adopts rules and definitions that confirm that companies such as ourselves are not required to post cash collateral for our derivative hedging contracts. In addition, even if we ourselves are not required to post cash collateral for our derivative contracts, the banks and other derivatives dealers who are our contractual counterparties will be required to comply with the Act's new requirements, and the costs of their compliance will likely be passed on to customers such as ourselves, thus decreasing the benefits to us of hedging transactions and reducing our profitability.

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

As of June 30, 2010, 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 program during the six months ended June 30, 2010.

The following table summarizes our repurchase activity during 2010 in connection with other arrangements:

Period	Total Number of Units Purchased	Average Price Paid per Unit	Total Number of Units Purchased as Part of Publicly Announced Plans	Maximum Number of Units That May Yet Be Purchased Under the Plans
February 2010 (1)	7,480	$32.17	--	--
May 2010 (2)	78,522	$35.60	--	--

(1) Of the 34,528 restricted units that vested in February 2010 and converted to common units, 7,480 units were sold back to us by employees to cover related withholding tax requirements.

(2) Of the 287,700 restricted units that vested in May 2010 and converted to common units, 78,522 units were sold back to us by employees to cover related withholding tax requirements.

Item 3. *Defaults upon Senior Securities.*

None.

Item 4. *(Removed and Reserved).*

Item 5. *Other Information.*

None.

Item 6. *Exhibits.*

Exhibit Number	Exhibit*
2.1	Merger Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed December 15, 2003).
2.2	Amendment No. 1 to Merger Agreement, dated as of August 31, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed September 7, 2004).
2.3	Parent Company Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.2 to Form 8-K filed December 15, 2003).
2.4	Amendment No. 1 to Parent Company Agreement, dated as of April 19, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.1 to Form 8-K filed April 21, 2004).
2.5	Purchase and Sale Agreement (Gas Plants), dated as of December 15, 2003, by and between El Paso Corporation, El Paso Field Services Management, Inc., El Paso Transmission, L.L.C., El Paso Field Services Holding Company and Enterprise Products Operating L.P. (incorporated by reference to Exhibit 2.4 to Form 8-K filed December 15, 2003).
2.6	Agreement and Plan of Merger, dated as of June 28, 2009, by and among Enterprise

	Products Partners L.P., Enterprise Products GP, LLC, Enterprise Sub B LLC, TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed June 29, 2009).
2.7	Agreement and Plan of Merger, dated as of June 28, 2009, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Sub A LLC, TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (incorporated by reference to Exhibit 2.2 to Form 8-K filed June 29, 2009).
3.1	Certificate of Limited Partnership of Enterprise Products Partners L.P. (incorporated by reference to Exhibit 3.6 to Form 10-Q filed November 9, 2007).
3.2	Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated August 8, 2005 (incorporated by reference to Exhibit 3.1 to Form 8-K filed August 10, 2005).
3.3	Amendment No. 1 to Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P. dated December 27, 2007 (incorporated by reference to Exhibit 3.1 to Form 8-K/A filed January 3, 2008).
3.4	Amendment No. 2 to Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P. dated April 14, 2008 (incorporated by reference to Exhibit 10.1 to Form 8-K filed April 16, 2008).
3.5	Amendment No. 3 to Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P. dated November 6, 2008 (incorporated by reference to Exhibit 3.5 to Form 10-Q filed November 10, 2008).
3.6	Amendment No. 4 to Fifth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P. dated October 26, 2009 (incorporated by reference to Exhibit 3.1 to Form 8-K filed October 28, 2009).
3.7	Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, dated November 7, 2007 (incorporated by reference to Exhibit 3.2 to Form 10-Q filed November 9, 2007).
3.8	First Amendment to Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, dated November 6, 2008 (incorporated by reference to Exhibit 3.7 to Form 10-Q filed November 10, 2008).
3.9	Company Agreement of Enterprise Products Operating LLC dated June 30, 2007 (incorporated by reference to Exhibit 3.3 to Form 10-Q filed August 8, 2007).
3.10	Certificate of Incorporation of Enterprise Products OLPGP, Inc., dated December 3, 2003 (incorporated by reference to Exhibit 3.5 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
3.11	Bylaws of Enterprise Products OLPGP, Inc., dated December 8, 2003 (incorporated by reference to Exhibit 3.6 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
4.1	Form of Common Unit certificate (incorporated by reference to Exhibit 4.1 to Form S-1A Registration Statement, Reg. No. 333-52537, filed July 21, 1998).
4.2	Indenture, dated as of March 15, 2000, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed March 10, 2000).
4.3	First Supplemental Indenture, dated as of January 22, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.4	Second Supplemental Indenture, dated as of February 14, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 10-K filed March 31, 2003).
4.5	Third Supplemental Indenture, dated as of June 30, 2007, among Enterprise Products Operating L.P., as Original Issuer, Enterprise Products Partners L.P., as Parent Guarantor, Enterprise Products Operating LLC, as New Issuer, and U.S. Bank National Association, as successor Trustee (incorporated by reference to Exhibit 4.55 to Form 10-Q filed August 8, 2007).

4.6	Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed October 6, 2004).
4.7	First Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed October 6, 2004).
4.8	Second Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 6, 2004).
4.9	Third Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed October 6, 2004).
4.10	Fourth Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 6, 2004).
4.11	Fifth Supplemental Indenture, dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed March 3, 2005).
4.12	Sixth Supplemental Indenture, dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed March 3, 2005).
4.13	Seventh Supplemental Indenture, dated as of June 1, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.46 to Form 10-Q filed November 4, 2005).
4.14	Eighth Supplemental Indenture, dated as of July 18, 2006, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006).
4.15	Ninth Supplemental Indenture, dated as of May 24, 2007, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed May 24, 2007).
4.16	Tenth Supplemental Indenture, dated as of June 30, 2007, among Enterprise Products Operating L.P., as Original Issuer, Enterprise Products Partners L.P., as Parent Guarantor, Enterprise Products Operating LLC, as New Issuer, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.54 to Form 10-Q filed August 8, 2007).
4.17	Eleventh Supplemental Indenture, dated as of September 4, 2007, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed September 5, 2007).
4.18	Twelfth Supplemental Indenture, dated as of April 3, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed April 3, 2008).
4.19	Thirteenth Supplemental Indenture, dated as of April 3, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to

	Form 8-K filed April 3, 2008).
4.20	Fourteenth Supplemental Indenture, dated as of December 8, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed December 8, 2008).
4.21	Fifteenth Supplemental Indenture, dated as of June 10, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed June 10, 2009).
4.22	Sixteenth Supplemental Indenture, dated as of October 5, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.23	Seventeenth Supplemental Indenture, dated as of October 27, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed October 28, 2009).
4.24	Eighteenth Supplemental Indenture, dated as of October 27, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed October 28, 2009).
4.25	Nineteenth Supplemental Indenture, dated as of May 20, 2010, 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 10-K filed May 20, 2010).
4.26	Global Note representing \$350.0 million principal amount of 6.375% Series B Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.27	Global Note representing \$499.2 million principal amount of 6.875% Series B Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 10-K filed March 31, 2003).
4.28	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).
4.29	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 March 4, 2005).
4.30	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 March 4, 2005).
4.31	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 March 4, 2005).
4.32	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 March 4, 2005).
4.33	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 filed March 15, 2005).
4.34	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 November 4, 2005).
4.35	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 November 4, 2005).
4.36	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).
4.37	Form of Junior Subordinated Note, including Guarantee (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006).
4.38	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).
4.39	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).
4.40	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).
4.41	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).
4.42	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).
4.43	Form of Global Note representing $500.0 million principal amount of 5.25% Senior Notes due 2020 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.44	Form of Global Note representing $600.0 million principal amount of 6.125% Senior Notes due 2039 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.45	Form of Global Note representing $490.5 million principal amount of 7.625% Senior Notes due 2012 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 28, 2009).
4.46	Form of Global Note representing $182.6 million principal amount of 6.125% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed October 28, 2009).
4.47	Form of Global Note representing $237.6 million principal amount of 5.90% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 28, 2009).
4.48	Form of Global Note representing $349.7 million principal amount of 6.65% Senior Notes due 2018 with attached Guarantee (incorporated by reference to Exhibit 4.6 to Form 8-K filed October 28, 2009).
4.49	Form of Global Note representing $399.6 million principal amount of 7.55% Senior Notes due 2038 with attached Guarantee (incorporated by reference to Exhibit 4.7 to Form 8-K filed October 28, 2009).
4.50	Form of Global Note representing $285.8 million principal amount of 7.000% Junior Subordinated Notes due 2067 with attached Guarantee (incorporated by reference to Exhibit 4.8 to Form 8-K filed October 28, 2009).
4.51	Form of Global Note representing $400.0 million principal amount of 3.70% Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed May 20, 2010).
4.52	Form of Global Note representing $1.0 billion principal amount of 5.20% Senior Notes due 2020 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed May 20, 2010).
4.53	Form of Global Note representing $600.0 million principal amount of 6.45% Senior Notes due 2040 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed May 20, 2010).
4.54	Replacement Capital Covenant, dated May 24, 2007, executed by Enterprise Products Operating L.P. and Enterprise Products Partners L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 99.1 to Form 8-K filed May 24, 2007).
4.55	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).

4.56	Purchase Agreement, dated as of July 12, 2006 between Cerrito Gathering Company, Ltd., Cerrito Gas Marketing, Ltd., Encinal Gathering, Ltd., as Sellers, Lewis Energy Group, L.P. as Guarantor, and Enterprise Products Partners L.P., as Buyer (incorporated by reference to Exhibit 4.6 to Form 10-Q filed August 8, 2006).
4.57	Replacement Capital Covenant, dated October 27, 2009, among Enterprise Products Operating LLC and Enterprise Products Partners L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 4.9 to Form 8-K filed October 28, 2009).
4.58	Indenture, dated February 20, 2002, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as Subsidiary Guarantors, and First Union National Bank, NA, as Trustee (incorporated by reference to Exhibit 99.2 to the Form 8-K filed by TEPPCO Partners, L.P. on February 20, 2002).
4.59	First Supplemental Indenture, dated February 20, 2002, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as Subsidiary Guarantors, and First Union National Bank, NA, as Trustee (incorporated by reference to Exhibit 99.3 to the Form 8-K filed by TEPPCO Partners, L.P. on February 20, 2002).
4.60	Second Supplemental Indenture, dated June 27, 2002, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as Initial Subsidiary Guarantors, Val Verde Gas Gathering Company, L.P., as New Subsidiary Guarantor, and Wachovia Bank, National Association, formerly known as First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.6 to the Form 10-Q filed by TEPPCO Partners, L.P. on August 14, 2002).
4.61	Third Supplemental Indenture, dated January 20, 2003, by and among TEPPCO Partners, L.P. as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Jonah Gas Gathering Company and Val Verde Gas Gathering Company, L.P. as Subsidiary Guarantors, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.7 to the Form 10-K filed by TEPPCO Partners, L.P. on March 21, 2003).
4.62	Full Release of Guarantee, dated July 31, 2006, by Wachovia Bank, National Association, as Trustee, in favor of Jonah Gas Gathering Company (incorporated by reference to Exhibit 4.8 to the Form 10-Q filed by TEPPCO Partners, L.P. on November 7, 2006).
4.63	Fourth Supplemental Indenture, dated June 30, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Val Verde Gas Gathering Company, L.P., TE Products Pipeline Company, LLC and TEPPCO Midstream Companies, LLC, as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.3 to the Form 8-K filed by TE Products Pipeline Company, LLC on July 6, 2007).
4.64	Fifth Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.11 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008).
4.65	Sixth Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.12 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008).
4.66	Seventh Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.13

	to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008).
4.67	Eighth Supplemental Indenture, dated October 27, 2009, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.1 to the Form 8-K filed by TEPPCO Partners, L.P. on October 28, 2009).
4.68	Full Release of Guarantee, dated November 23, 2009, of TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P. by U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.64 to Form 10-K filed on March 1, 2010).
4.69	Indenture, dated May 14, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 99.1 of the Form 8-K filed by TEPPCO Partners, L.P. on May 15, 2007).
4.70	First Supplemental Indenture, dated May 18, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TEPPCO Partners, L.P. on May 18, 2007).
4.71	Replacement of Capital Covenant, dated May 18, 2007, executed by TEPPCO Partners, L.P., TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P. in favor of the covered debt holders described therein (incorporated by reference to Exhibit 99.1 to the Form 8-K of TEPPCO Partners, L.P. on May 18, 2007).
4.72	Second Supplemental Indenture, dated as of June 30, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Existing Subsidiary Guarantors, TE Products Pipeline Company, LLC and TEPPCO Midstream Companies, LLC, as New Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TE Products Pipeline Company, LLC on July 6, 2007).
4.73	Third Supplemental Indenture, dated as of October 27, 2009, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TEPPCO Partners, L.P. on October 28, 2009).
4.74	Full Release of Guarantee, dated as of November 23, 2009, of TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P. by The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.70 to Form 10-K filed on March 1, 2010).
10.1*** #	Amendment to Form of Option Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued before February 23, 2010.
10.2*** #	Amendment to Form of Option Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued before August 5, 2010.
10.3*** #	Form of Option Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan.
10.4*** #	Amendment to Form of Restricted Unit Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued before August 5, 2010.
10.5*** #	Form of Employee Restricted Unit Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan.
10.6***	Form of Option Grant Award under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to Form 10-Q filed by Enterprise GP Holdings L.P. on August 9, 2010).
10.7***	Form of Employee Restricted Unit Grant Award under the Enterprise Products Company

	2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to Form 10-Q filed by Enterprise GP Holdings L.P. on August 9, 2010).
10.8***	Form of Phantom Unit Grant Award under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Form 10-Q filed by Enterprise GP Holdings L.P. on August 9, 2010).
10.9*** #	Amendment to Form of Option Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan for awards issued before February 23, 2010.
10.10*** #	Amendment to Form of Option Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan for awards issued before August 5, 2010.
10.11*** #	Form of Option Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan.
10.12*** #	Amendment to Form of Restricted Unit Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan for awards issued before August 5, 2010.
10.13*** #	Form of Employee Restricted Unit Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan.
10.14***	Form of Option Grant Award under the 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.14 to Form 10-Q filed by Duncan Energy Partners L.P. on August 9, 2010).
10.15***	Form of Employee Restricted Unit Grant Award under the 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.15 to Form 10-Q filed by Duncan Energy Partners L.P. on August 9, 2010).
10.16	Second Amended and Restated Limited Liability Company Agreement of Acadian Gas, LLC, dated June 1, 2010 (incorporated by reference to Exhibit 10.01 to Form 8-K filed by Duncan Energy Partners L.P. on June 3, 2010).
10.17	Loan Agreement, dated June 1, 2010, between Enterprise Products Operating LLC, as lender, and Duncan Energy Partners L.P., as borrower (incorporated by reference to Exhibit 10.02 to Form 8-K filed by Duncan Energy Partners L.P. on June 3, 2010).
31.1#	Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise Products Partners L.P. for the June 30, 2010 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, 2010 quarterly report on Form 10-Q.
32.1#	Section 1350 certification of Michael A. Creel for the June 30, 2010 quarterly report on Form 10-Q.
32.2#	Section 1350 certification of W. Randall Fowler for the June 30, 2010 quarterly report on Form 10-Q.
101.CAL#	XBRL Calculation Linkbase Document
101.DEF#	XBRL Definition Linkbase Document
101.INS#	XBRL Instance Document
101.LAB#	XBRL Labels Linkbase Document
101.PRE#	XBRL Presentation Linkbase Document
101.SCH#	XBRL Schema Document

* With respect to any exhibits incorporated by reference to any Exchange Act filings, the Commission file numbers for Enterprise GP Holdings L.P, Duncan Energy Partners L.P., TEPPCO Partners, L.P. and TE Products Pipeline Company, LLC are 1-32610, 1-33266, 1-10403 and 1-13603, respectively.

*** Identifies management contract and compensatory plan arrangements.

\# 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 9, 2010.

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