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 March 31, 2010

OR

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

For the transition period from ___ to ___.

Commission file number: 1-14323

ENTERPRISE PRODUCTS PARTNERS L.P.

(Exact name of Registrant as Specified in Its Charter)

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

1100 Louisiana 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 o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

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

Yes o No ☑

There were 634,754,083 common units, including 3,925,381 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 May 3, 2010. These common units trade on the New York Stock Exchange under the ticker symbol "EPD."

ENTERPRISE PRODUCTS PARTNERS L.P.
TABLE OF CONTENTS

PART I. FINANCIAL INFORMATION.

Item 1. *Financial Statements.*

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

ASSETS	March 31, 2010	December 31, 2009
Current assets:		
Cash and cash equivalents	$ 134.9	$ 54.7
Restricted cash	101.7	63.6
Accounts and notes receivable – trade, net of allowance for doubtful accounts of $17.5 at March 31, 2010 and $16.8 at December 31, 2009	3,056.0	3,099.0
Accounts receivable – related parties	26.9	38.4
Inventories	990.9	711.9
Prepaid and other current assets	296.8	279.3
Total current assets	4,607.2	4,246.9
Property, plant and equipment, net	17,735.3	17,689.2
Investments in unconsolidated affiliates	883.5	890.6
Intangible assets, net of accumulated amortization of $824.6 at March 31, 2010 and $795.0 at December 31, 2009	1,035.2	1,064.8
Goodwill	2,018.3	2,018.3
Other assets	221.6	241.8
Total assets	$ 26,501.1	$ 26,151.6
LIABILITIES AND EQUITY		
Current liabilities:		
Current maturities of long-term debt	$ 175.0	$ --
Accounts payable – trade	419.0	410.6
Accounts payable – related parties	47.8	69.8
Accrued product payables	3,695.1	3,393.0
Accrued expenses	79.4	108.5
Accrued interest	170.0	228.0
Other current liabilities	354.4	326.1
Total current liabilities	4,940.7	4,536.0
Long-term debt (see Note 9)	10,915.7	11,346.4
Deferred tax liabilities	72.5	71.7
Other long-term liabilities	160.2	155.2
Commitments and contingencies		
Equity: (see Note 10)		
Enterprise Products Partners L.P. partners' equity:		
Limited Partners:		
Common units (617,009,491 units outstanding at March 31, 2010 and 603,202,828 units outstanding at December 31, 2009)	9,575.4	9,173.5
Restricted common units (3,925,881 units outstanding at March 31, 2010 and 2,720,882 units outstanding at December 31, 2009)	43.7	37.7
Class B units (4,520,431 units outstanding at March 31, 2010 and December 31, 2009)	118.5	118.5
General partner	199.1	190.8
Accumulated other comprehensive loss	(54.6)	(8.4)
Total Enterprise Products Partners L.P. partners' equity	9,882.1	9,512.1
Noncontrolling interest	529.9	530.2
Total equity	10,412.0	10,042.3
Total liabilities and equity	$ 26,501.1	$ 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 March 31, 2010	For the Three Months Ended March 31, 2009*
Revenues:		
Third parties	$ 8,312.1	$ 4,667.4
Related parties	232.4	219.5
Total revenues (see Note 11)	8,544.5	4,886.9
Costs and expenses:		
Operating costs and expenses:		
Third parties	7,647.9	4,147.1
Related parties	324.0	229.5
Total operating costs and expenses	7,971.9	4,376.6
General and administrative costs:		
Third parties	14.1	7.9
Related parties	23.5	27.0
Total general and administrative costs	37.6	34.9
Total costs and expenses	8,009.5	4,411.5
Equity in income of unconsolidated affiliates	16.0	7.4
Operating income	551.0	482.8
Other income (expense):		
Interest expense	(148.6)	(152.5)
Interest income	0.2	0.9
Other, net	(0.1)	0.3
Total other expense, net	(148.5)	(151.3)
Income before provision for income taxes	402.5	331.5
Provision for income taxes	(8.7)	(16.0)
Net income	393.8	315.5
Net income attributable to noncontrolling interest	(16.0)	(90.2)
Net income attributable to Enterprise Products Partners L.P.	$ 377.8	$ 225.3
Net income allocated to:		
Limited partners	$ 317.4	$ 186.3
General partner	$ 60.4	$ 39.0
Basic earnings per unit (see Note 13)	$ 0.51	$ 0.41
Diluted earnings per unit (see Note 13)	$ 0.50	$ 0.41

See Notes to Unaudited Condensed Consolidated Financial Statements.
*See Note 1 for information regarding these recasted 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 March 31,	
	2010	**2009***
Net income	$ 393.8	$ 315.5
Other comprehensive income (loss):		
Cash flow hedges:		
Commodity derivative instrument losses during period	(58.9)	(62.0)
Reclassification adjustment for losses included in net income related to commodity derivative instruments	16.5	32.2
Interest rate derivative instrument losses during period	(5.7)	(0.7)
Reclassification adjustment for losses included in net income related to interest rate derivative instruments	3.3	2.3
Foreign currency derivative losses during period	(0.1)	(10.6)
Reclassification adjustment for gains included in net income related to foreign currency derivative instruments	(0.3)	--
Total cash flow hedges	(45.2)	(38.8)
Foreign currency translation adjustment	0.6	(0.4)
Change in funded status of pension and postretirement plans, net of tax	(0.9)	--
Total other comprehensive loss	(45.5)	(39.2)
Comprehensive income	348.3	276.3
Comprehensive income attributable to noncontrolling interest	(16.7)	(92.2)
Comprehensive income attributable to Enterprise Products Partners L.P.	$ 331.6	$ 184.1

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

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

	For the Three Months Ended March 31, 2010	For the Three Months Ended March 31, 2009*
Operating activities:		
Net income	$ 393.8	$ 315.5
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	217.6	199.1
Non-cash impairment charges	1.5	--
Equity in income of unconsolidated affiliates	(16.0)	(7.4)
Distributions received from unconsolidated affiliates	30.2	22.4
Operating lease expenses paid by EPCO	0.2	0.2
Gain from asset sales and related transactions	(7.5)	(0.2)
Deferred income tax expense	1.0	0.9
Changes in fair market value of derivative instruments	(7.8)	(12.6)
Effect of pension settlement recognition	(0.2)	(0.1)
Net effect of changes in operating accounts (see Note 16)	74.1	(145.8)
Net cash flows provided by operating activities	686.9	372.0
Investing activities:		
Capital expenditures	(347.8)	(513.9)
Contributions in aid of construction costs	3.6	6.4
Increase in restricted cash	(38.1)	(40.7)
Cash used for business combinations	(2.2)	--
Acquisition of intangible assets	--	(1.4)
Investments in unconsolidated affiliates	(7.7)	(7.1)
Proceeds from asset sales and related transactions	21.7	0.3
Other investing activities	--	3.8
Cash used in investing activities	(370.5)	(552.6)
Financing activities:		
Borrowings under debt agreements	345.5	1,163.4
Repayments of debt	(595.0)	(915.9)
Debt issuance costs	(0.1)	(0.9)
Cash distributions paid to partners	(407.3)	(279.7)
Cash distributions paid to noncontrolling interest	(17.4)	(105.5)
Cash contributions from noncontrolling interest	0.2	(0.6)
Net cash proceeds from issuance of common units	437.7	310.8
Acquisition of treasury units	(0.2)	--
Cash provided by (used in) financing activities	(236.6)	171.6
Effect of exchange rate changes on cash	0.4	(2.0)
Net change in cash and cash equivalents	79.8	(9.0)
Cash and cash equivalents, January 1	54.7	61.7
Cash and cash equivalents, March 31	$ 134.9	$ 50.7

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

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED EQUITY
(See Note 10 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	317.4	60.4	--	16.0	393.8
Operating lease expenses paid by EPCO	0.2	--	--	--	0.2
Cash distributions paid to partners	(345.5)	(60.9)	--	--	(406.4)
Unit option reimbursements to EPCO	(0.9)	--	--	--	(0.9)
Cash distributions paid to noncontrolling interest	--	--	--	(17.4)	(17.4)
Net cash proceeds from issuance of common units	428.3	8.8	--	--	437.1
Cash proceeds from exercise of unit options	0.6	--	--	--	0.6
Cash contributions from noncontrolling interest	--	--	--	0.2	0.2
Amortization of equity awards	8.0	--	--	0.2	8.2
Acquisition of treasury units	(0.2)	--	--	--	(0.2)
Foreign currency translation adjustment	--	--	0.6	--	0.6
Change in funded status of pension and postretirement plans, net of tax	--	--	(0.9)	--	(0.9)
Cash flow hedges	--	--	(45.9)	0.7	(45.2)
Balance, March 31, 2010	$ 9,737.6	$ 199.1	$ (54.6)	$ 529.9	$ 10,412.0

	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	186.3	39.0	--	90.2	315.5
Operating lease expenses paid by EPCO	0.2	--	--	--	0.2
Cash distributions paid to partners	(239.5)	(40.1)	--	--	(279.6)
Unit option reimbursements to EPCO	(0.1)	--	--	--	(0.1)
Cash distributions paid to noncontrolling interest	--	--	--	(105.5)	(105.5)
Net cash proceeds from issuance of common units	304.5	6.2	--	--	310.7
Cash proceeds from exercise of unit options	0.1	--	--	--	0.1
Cash contributions from noncontrolling interest	--	--	--	(0.6)	(0.6)
Amortization of equity awards	2.7	0.1	--	1.1	3.9
Foreign currency translation adjustment	--	--	(0.4)		(0.4)
Cash flow hedges	--	--	(40.8)	2.0	(38.8)
Balance, March 31, 2009*	$ 6,317.3	$ 128.8	$ (138.4)	$ 3,193.6	$ 9,501.3

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

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 through which Enterprise Products Partners conducts substantially all of its business, 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"), 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, 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 Dan L. Dun can, 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: (1) Randa Duncan Williams, Mr. Duncan's oldest daughter, who is also an existing director on the board of EPE Holdings; (2) Dr. Ralph S. Cunningham, who is currently the President and Chief Executive Officer ("CEO") of EPE Holdings; and (3) Richard H. Bachmann, who is currently the Executive Vice President and Chief Legal Officer of EPGP and one of three managers of Dan Duncan LLC. Dr. Cunningham and Mr. Bachmann are also currently directors of EPGP, EPE Holdings and DEP GP.

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.

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The DD LLC Trustees are required to treat the member party to the DD LLC Voting Trust Agreement as the beneficial owner for all purposes whatsoever of the membership interests of Dan Duncan LLC. The estate of Dan L. 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 rec eive 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 (1) the descendants of Dan L. 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 (2) 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 Dan L. 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 "TEPPCO" and "TEPPCO GP" mean TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (which is the general partner of TEPPCO), respectively, prior to their mergers with our subsidiaries. On October 26, 2009, we completed the mergers with TEPPCO and TEPPCO GP (such related mergers referred to herein individually and together as the "TEPPCO Merger").

References to "Energy Transfer Equity" mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries, which include Energy Transfer Partners, L.P. ("ETP"). Energy Transfer Equity is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "ETE." ETP is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "ETP." The general partner of Energy Transfer Equity is LE GP, LLC.

References to "EPCO" mean Enterprise Products Company (formerly EPCO, Inc.) and its privately held affiliates. Prior to Mr. Duncan's death on March 29, 2010, we, EPO, Duncan Energy Partners, DEP GP, EPGP, Enterprise GP Holdings and EPE Holdings were affiliates under the common control of Dan L. Duncan, the controlling shareholder of EPCO. 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 dated April 26, 2006 (the "EPCO Voting Trust Agreement"), among EPCO, Dan L. 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 Dan L. Duncan, as the initial sole voting trus tee. Immediately upon Mr. Duncan's death, voting and dispositive control of such majority of the outstanding voting capital stock of EPCO included under the EPCO Voting Trust Agreement was transferred pursuant to the EPCO Voting Trust Agreement to three voting trustees (the "EPCO Trustees"). The current EPCO Trustees are: (1) Ms. Williams, who serves as Chairman of EPCO; (2) Dr..Cunningham, who serves as a Vice Chairman of EPCO; and (3) 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 for the DD LLC Voting Trust, which controls 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 Dan L. Duncan. Dan Duncan LLC and EPCO also beneficially own approximately 18% and 57%, respectively, of the outstanding units representing limited partner interests of Enterprise GP Holdings.

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 Organization and Basis of Presentation

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 conduct substantially all of our business through our wholly owned subsidiary, EPO. We are owned 98% by our limited partners and 2% by our general partner, EPGP. Enterprise GP Holdings owns 100% of EPGP. The general partner of Enterprise GP Holdings is EPE Holdings, a wholly owned subsidiary of Dan Duncan LLC. Mr. Dan L. Duncan owned all of the membership interests of Dan Duncan LLC prior to his death on March 29, 2010. All of the membership interests of Dan Duncan LLC are currently owned of record collectively by the DD LLC Trustees. We, EPGP, Enterprise GP Holdings, EPE Holdings and Dan Duncan LLC are affiliates and under the collective common control of the DD LLC Trustees and the EPCO Trustees. The EPCO Trustees are collectively the controlling record shareholders of EPCO.

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. Also, due to common control of the entities by Dan L. Duncan during his lifetime, and thereafter by the DD LLC Trustees and the EPCO Trustees, collectively, the initial consolidated balance sheet of Duncan Energy Partners reflects our historical carrying basis in each of the subsidiaries contributed to Duncan Energy Partners. Public ownership of Duncan Energy Partners' net assets and earnings are presented as a component of noncontrolling interest in our consolidated financial statements. The borrowings of Duncan Energy Partners are pr esented 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

Our consolidated financial statements and business segments were recast in connection with the TEPPCO Merger. On October 26, 2009, the related mergers of our wholly owned subsidiaries with TEPPCO and TEPPCO GP were completed. Under terms of the merger agreements, TEPPCO and TEPPCO GP became wholly owned subsidiaries of ours, and each of TEPPCO's unitholders, except for a privately held affiliate of EPCO, were entitled to receive 1.24 of our common units for each TEPPCO unit. In total, we issued an aggregate of 126,932,318 common units and 4,520,431 Class B units (described below) as consideration in the TEPPCO Merger for both TEPPCO units and the TEPPCO GP membership interests. TEPPCO's units, which had been trading on the NYSE under the ticker symbol "TPP," have been delisted a nd are no longer publicly traded. 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 regular quarterly cash distributions for the first 16 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 16th 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.

Since Enterprise Products Partners, TEPPCO and TEPPCO GP were under common control of EPCO and its affiliates, 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. The inclusion of TEPPCO and TEPPCO GP in our consolidated financial statements was effective January 1, 2005 since an affiliate of EPCO under common control with Enterprise Products Partners originally acquired ownership interests in TEPPCO GP in February 2005.

Our consolidated financial statements 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 reflected as “Former owners of TEPPCO,” a component of noncontrolling interest. The financial statements of TEPPCO and TEPPCO GP were prepared from the separate accounting records maintained by TEPPCO and TEPPCO GP. All intercompany balances and transactions have been eliminated in consolidation.

We revised our business segments and related disclosures to reflect the TEPPCO Merger. Our reorganized business segments reflect the manner in which these businesses are managed and reviewed by the CEO of our general partner. Under our new business segment structure, 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.

There was no change in net income attributable to Enterprise Products Partners L.P. for periods prior to the merger since net income attributable to TEPPCO and TEPPCO GP was allocated to noncontrolling interests. Additionally, there was no change in our reported earnings per unit for such periods. See Note 11 for a reconciliation of our consolidated revenues and total segment gross operating margin, which is a non-generally accepted accounting principle (“non-GAAP”) financial measure of segment performance, to our pre-merger amounts.

Our results of operations for the three months ended March 31, 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 Notes 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 (our “2009 Form 10-K”).

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 (i.e. assets, liabilities, revenue and expenses) and disclosures about contingent assets and liabilities. Our actual results could differ from these estimates. On an ongoing basis, management reviews its estimates based on currently available information. Changes in facts and circumstances may result in revised estimates.

Fair Value Information

Cash and cash equivalents and restricted cash, accounts receivable, accounts payable and accrued expenses, and other current liabilities (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:

	March 31, 2010		December 31, 2009	
Financial Instruments	**Carrying Value**	**Fair Value**	**Carrying Value**	**Fair Value**
Financial assets:				
Cash and cash equivalents and restricted cash	$ 236.6	$ 236.6	$ 118.3	$ 118.3
Accounts receivable	3,082.9	3,082.9	3,137.4	3,137.4
Financial liabilities:				
Accounts payable and accrued expenses	4,411.3	4,411.3	4,209.9	4,209.9
Other current liabilities (excluding derivative instruments)	222.8	222.8	233.1	233.1
Fixed-rate debt (principal amount)	10,532.7	11,156.2	10,586.7	11,056.2
Variable-rate debt	514.8	514.8	710.3	710.3

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 March 31, 2010 and December 31, 2009, our restricted cash amounts were $101.7 million and $63.6 million, respectively. See Note 4 for information regarding derivative instruments and hedging activities.

Note 3. Equity-based Awards

The following table summarizes the expense we recognized in connection with equity-based awards for the periods indicated:

	For the Three Months Ended March 31,	
	2010	**2009**
Restricted unit awards (1)	$ 5.3	$ 2.4
Unit option awards (1)	0.9	0.1
Unit appreciation rights (2)	0.1	--
Profits interests awards (1)	1.8	1.4
Total compensation expense	$ 8.1	$ 3.9

(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 on a straight-line basis 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 March 31, 2010, the active long-term incentive plans 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, we had unvested awards issued, but are not issuing further awards, under the Enterprise Products 2006 TPP Long-Term Incentive Plan ("2006 Plan").

An allocated portion of the fair value of these long-term incentive plan equity-based awards is charged to us under the administrative services agreement ("ASA"). See Note 12 for a general description of the ASA with EPCO. With the exception of certain amounts recorded in connection with EPCO Unit, we are not responsible for reimbursing EPCO for any expenses associated with such awards. We recognize an expense for our allocated share of the grant date fair value of such awards, with an offsetting amount recorded in equity. 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. Our reimbursements t o EPCO in connection with EPCO Unit were $0.1 million during each of the three months ended March 31, 2010 and 2009.

Restricted Unit Awards

Restricted unit awards allow recipients to acquire our common units or common units of Duncan Energy Partners (at no cost to the recipient) once a defined vesting period expires, subject to customary forfeiture provisions. The majority of these awards are subject to cliff vesting, the restrictions on such awards generally lapse four years from the date of grant. There are also awards that are subject to graded vesting provisions by which one-fourth of each award vests on each of the first, second, third and fourth anniversaries of the date of grant. The fair value of restricted units 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. & #160;Compensation expense for awards with graded vesting provisions is recognized on a straight-line basis over the requisite period of each separately vesting portion of the award. As used in the context of our 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 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 restricted unit awards		
Restricted units at December 31, 2009	2,720,882	$ 27.70
Granted (2) (3)	1,290,075	$ 32.27
Vested (3)	(34,528)	$ 26.62
Forfeited	(50,548)	$ 28.82
Restricted units at March 31, 2010	3,925,881	$ 29.35
Duncan Energy Partners 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 March 31, 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 our restricted unit awards issued during 2010 was $41.6 million based on grant date market price of our common units of $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 board of directors of EPGP and DEP GP as part of their annual compensation in February 2010 and immediately vested.
(4) Aggregate grant date fair value of Duncan Energy Partners' restricted unit awards issued during 2010 was $0.2 million based on grant date market prices of Duncan Energy Partners' common units of $25.26 per unit.

On a gross basis, the total unrecognized compensation cost of such awards was $68.0 million at March 31, 2010, of which our share is currently estimated to be $62.1 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.2 years.

Unit Option Awards

Certain long-term incentive plans provide for the issuance of non-qualified incentive options to purchase a fixed number of our common units or common units of Duncan Energy Partners. 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, options granted under the EPCO plans have a vesting period of four years and remain exercisable for five to ten years, as applicable, from the date of grant.

The following table presents unit option activity under the long-term incentive plans for the periods indicated:

	Number of Units	Weighted-Average Strike Price (dollars/unit)	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (1)
Outstanding at December 31, 2009	3,825,920	$ 26.52		
Granted (2)	755,000	$ 32.27		
Exercised	(97,500)	$ 22.77		
Outstanding at March 31, 2010	4,483,420	$ 27.57	4.6	$ 3.1
Options exercisable at March 31, 2010	350,000	$ 25.74	4.9	$ 3.1

(1) Aggregate intrinsic value reflects fully vested unit options at the date indicated.
(2) Aggregate grant date fair value of these unit options issued during 2010 was $2.2 million based on the following assumptions: (i) a grant date market price of our common units of $32.27 per unit; (ii) expected life of options of 4.9 years; (iii) risk-free interest rate of 2.4%; (iv) expected distribution yield on our common units of 6.9% and (v) expected unit price volatility on our common units of 23.2%. An estimated forfeiture rate of 17% was applied to awards granted during 2010.

The following table presents additional information regarding our unit options for the periods indicated:

	For the Three Months Ended March 31, 2010	2009
Total intrinsic value of option awards exercised during period	$ 0.9	$ 0.1
Cash received from EPCO in connection with the exercise of unit option awards	0.6	0.1
Option-related reimbursements to EPCO	0.9	0.1

On a gross basis, the total unrecognized compensation cost of such awards was $10.1 million at March 31, 2010, of which our share is currently estimated to be $9.1 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.9 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 additional information regarding our UARs for the periods indicated:

	UARs Issued by		
	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 March 31, 2010	131,941	90,000	221,941

	For the Three Months Ended March 31,	
	2010	**2009**
Accrued liability for UARs, at end of period	$ 0.4	$ 0.1

At March 31, 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, these UAR awards are forfeited.

The non-employee directors of DEP GP, the general partner of Duncan Energy Partners, have been granted UARs in the form of letter agreements. These liability awards are not part of any established long-term incentive plan of EPCO, Enterprise GP Holdings, Duncan Energy Partners or us. The compensation expense associated with these awards is recognized by DEP GP, which is our consolidated subsidiary. At March 31, 2010, there were a total of 90,000 outstanding UARs granted to non-employee directors of DEP GP that cliff vest in 2012. If a director resigns prior to vesting, his UAR awards are forfeited. The grant date fair value with respect to these UARs is based on an Enterprise GP Holdings' unit price of $36.68.

Phantom Units

Certain of our 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 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. Our phantom units are accounted for as liability awards.

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

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

	For the Three Months Ended March 31,	
	2010	**2009**
Accrued liability for phantom unit awards, at end of period	$ 0.1	$ 0.4
Liabilities paid for phantom unit awards	0.1	0.8

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 has 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 private company 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 Enterprise Products Partners or a combination of both. The profits interests awards are subject to customary forfeiture provisions.

The total unrecognized compensation cost of the profits interests awards was $52.7 million at March 31, 2010, of which our share is currently estimated to be $43.0 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 5.9 years.

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 o ur 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 are related. After meeting specified conditions, a qualified derivative may be specifically designated as a total or partial hedge of:

§ Changes in the fair value of a recognized asset or liability, or an unrecognized firm commitment - In a fair value hedge, 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) ("OCI") 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 changes in the fair value of a hedged item at inception and throughout the life of the hedging relationship. The effective portion of a hedge 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.

Interest Rate Derivative Instruments

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

The following table summarizes our interest rate derivative instruments outstanding at March 31, 2010, all of which were designated as hedging instruments under the derivative and hedging guidance of the Financial Accounting Standards Board ("FASB"):

Hedged Transaction	Number and Type of Derivative Employed	Notional Amount	Period of Hedge	Rate Swap	Accounting Treatment
Enterprise Products Partners:					
Senior Notes C	1 fixed-to-floating swap	$100.0	1/04 to 2/13	6.4% to 2.3%	Fair value hedge
Senior Notes G	3 fixed-to-floating swaps	$300.0	10/04 to 10/14	5.6% to 1.5%	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	0.3% to 4.6%	Cash flow hedge

Changes in the fair value of the interest rate swaps and the related hedged items in a fair value hedge were recorded on the balance sheet with the offset recorded as interest expense. Cash flow hedges fix the interest rate paid on floating rate debt with the difference between the floating rate and fixed rate being recorded as an increase or decrease to interest expense. This combined activity resulted in a decrease in interest expense of $4.3 million for the three months ended March 31, 2010 and an increase in interest expense of $0.6 million for the three months ended March 31, 2009.

The following table summarizes our forward starting interest rate swaps outstanding at March 31, 2010, which hedge the underlying benchmark interest payments related to the forecasted issuances of debt:

Hedged Transaction	Number and Type of Derivative Employed	Notional Amount	Period of Hedge	Average Rate Locked	Accounting Treatment
Future debt offering	1 forward starting swap	$50.0	6/10 to 6/20	3.3%	Cash flow hedge
Future debt offering	3 forward starting swaps	$250.0	2/11 to 2/21	3.6%	Cash flow hedge
Future debt offering	6 forward starting swaps	$300.0	2/12 to 2/22	4.7%	Cash flow hedge

In April and May 2010, we entered into four additional forward starting swaps each with a notional amount of $50.0 million. The period hedged by these four forward starting swaps is February 2012 through February 2022.

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 forwards, basis swaps, futures and options contracts. The following table summarizes our commodity derivative instruments outstanding at March 31, 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)	26.5 Bcf	n/a	Cash flow hedge
Forecasted NGL sales (4)	6.3 MMBbls	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchases of NGLs	2.1 MMBbls	n/a	Cash flow hedge
NGLs inventory management	0.1 MMBbls	n/a	Cash flow hedge
Forecasted sales of octane enhancement products	3.2 MMBbls	0.4 MMBbls	Cash flow hedge
Natural gas marketing:			
Natural gas storage inventory management activities	1.9 Bcf	1.2 Bcf	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products	11.1 MMBbls	0.5 MMBbls	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products	10.9 MMBbls	0.7 MMBbls	Cash flow hedge
Derivatives not designated as hedging instruments:			
Enterprise Products Partners:			
Natural gas risk management activities (5) (6)	315.4 Bcf	51.2 Bcf	Mark-to-market
NGL risk management activities (6)	0.4 MMBbls	n/a	Mark-to-market
Crude oil risk management activities (6)	9.4 MMBbls	n/a	Mark-to-market
Duncan Energy Partners:			
Natural gas risk management activities (6)	1.4 Bcf	n/a	Mark-to-market

(1) Volume for derivatives designated as hedging instruments reflects the total amount of volumes hedged whereas volume for derivatives not designated as hedging instruments reflects the absolute value of derivative notional volumes.
(2) The maximum term for derivatives included in the long-term column is December 2012.
(3) PTR represents the British thermal unit equivalent of the NGLs extracted from natural gas by a processing plant, and includes the natural gas used as plant fuel to extract those liquids, plant flare and other shortages. See the discussion below for the primary objective of this strategy.
(4) Excludes 6.1 million barrels (“MMBbls”) of additional hedges executed under contracts that have been designated as normal sales agreements under the FASB’s derivative and hedging guidance. The combination of these volumes with the 6.3 MMBbls reflected as derivatives in the table above results in a total of 12.4 MMBbls of hedged forecasted NGL sales volumes, which corresponds to the 26.5 billion cubic feet (“Bcf”) of forecasted natural gas purchase volumes for PTR.
(5) Current and long-term volumes include approximately 134.9 and 9.9 Bcf, respectively, of physical derivative instruments that are predominantly priced at an index plus a premium or minus a discount.
(6) Reflects the use of derivative instruments to manage risks associated with transportation, processing and storage assets.

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

Our three predominant hedging strategies are hedging natural gas processing margins, hedging anticipated future sales of NGLs, refined products and crude oil associated with volumes held in inventory and hedging the fair value of natural gas in inventory. The objective of our natural gas processing strategy is to hedge an amount of gross margin associated with the gas processing activities. We achieve this by using physical and financial instruments to lock in the prices of natural gas purchases used for PTR and related NGL sales. This program consists of (i) the forward sale of a portion of our expected equity NGL production at fixed prices through December 2010, achieved through the use of forward physical sales and commodity derivative instruments and (ii) the purchase of commodity derivative instruments with a notional amount determined by the amount 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 anticipated future sales of inventory by locking in the sales price through the use of forward physical sales 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 the exchange rate. Long-term transactions (more than two months) are accounted for as cash flow hedges. Shorter term transactions are accounted for using mark-to-market accounting. At March 31, 2010, we did not have any foreign currency derivative instruments outstanding.

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 March 31, 2010, the aggregate fair value of our over-the-counter derivative instruments in a net liability position was $5.8 million, all of which was subject to a credit rating contingent f eature. If our credit ratings were downgraded to Ba2/BB, approximately $0.8 million would be payable as a margin deposit to the counterparties, and if our credit ratings were downgraded to Ba3/BB- or below, approximately $5.8 million would be payable as a margin deposit to the counterparties. Currently, no margin is required to be deposited. The potential for derivatives with contingent features to enter a net liability position may change in the future as positions and prices fluctuate.

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

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

	Asset Derivatives				Liability Derivatives			
	March 31, 2010		December 31, 2009		March 31, 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	$ 44.5	Other current assets	$ 32.7	Other current liabilities	$ 3.8	Other current liabilities	$ 5.5
Interest rate derivatives	Other assets	19.7	Other assets	31.8	Other liabilities	0.1	Other liabilities	2.2
Total interest rate derivatives		64.2		64.5		3.9		7.7
Commodity derivatives	Other current assets	47.9	Other current assets	52.0	Other current liabilities	89.4	Other current liabilities	62.6
Commodity derivatives	Other assets	0.9	Other assets	0.5	Other liabilities	2.1	Other liabilities	1.8
Total commodity derivatives (1)		48.8		52.5		91.5		64.4
Foreign currency derivatives	Other current assets	--	Other current assets	0.2	Other current liabilities	--	Other current liabilities	--
Total derivatives designated as hedging instruments		$ 113.0		$ 117.2		$ 95.4		$ 72.1
Derivatives not designated as hedging instruments								
Commodity derivatives	Other current assets	$ 43.0	Other current assets	$ 28.9	Other current liabilities	$ 38.4	Other current liabilities	$ 24.9
Commodity derivatives	Other assets	3.4	Other assets	2.0	Other liabilities	10.3	Other liabilities	2.7
Total commodity derivatives		46.4		30.9		48.7		27.6
Total derivatives not designated as hedging instruments		$ 46.4		$ 30.9		$ 48.7		$ 27.6

(1) Represent commodity derivative instrument transactions that either have not settled or have settled and not been invoiced. Settled and invoiced transactions are reflected in either accounts receivable or accounts payable depending on the outcome of the transaction.

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 March 31,	
		2010	**2009**
Interest rate derivatives	Interest expense	$ 7.4	$ (1.3)
Commodity derivatives	Revenue	(1.8)	0.3
Total		$ 5.6	$ (1.0)

Derivatives in Fair Value Hedging Relationships	**Location**	**Gain/(Loss) Recognized in Income on Hedged Item**	
		For the Three Months Ended March 31,	
		2010	**2009**
Interest rate derivatives	Interest expense	$ (7.4)	$ 1.3
Commodity derivatives	Revenue	1.9	0.1
Total		$ (5.5)	$ 1.4

Derivatives in Cash Flow Hedging Relationships	Change in Value Recognized in OCI on Derivative (Effective Portion)	
	For the Three Months Ended March 31,	
	2010	2009
Interest rate derivatives	$ (5.7)	$ (0.7)
Commodity derivatives – Revenue	(7.1)	(10.0)
Commodity derivatives – Operating costs and expenses	(51.8)	(52.0)
Foreign currency derivatives	(0.1)	(10.6)
Total	$ (64.7)	$ (73.3)

Derivatives in Cash Flow Hedging Relationships	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	
		For the Three Months Ended March 31,	
		2010	2009
Interest rate derivatives	Interest expense	$ (3.3)	$ (2.3)
Commodity derivatives	Revenue	(15.8)	15.3
Commodity derivatives	Operating costs and expenses	(0.7)	(47.5)
Foreign currency derivatives	Other income	0.3	--
Total		$ (19.5)	$ (34.5)

Derivatives in Cash Flow Hedging Relationships	Location of Loss Recognized in Income on Ineffective Portion of Derivative	Amount of Loss Recognized in Income on Ineffective Portion of Derivative	
		For the Three Months Ended March 31,	
		2010	2009
Commodity derivatives	Operating costs and expenses	$ (0.6)	$ (1.1)
Total		$ (0.6)	$ (1.1)

Over the next twelve months, we expect to reclassify $9.0 million of accumulated other comprehensive income (loss) ("AOCI") attributable to interest rate derivative instruments into earnings as an increase to interest expense. Likewise, we expect to reclassify $40.8 million of accumulated other comprehensive loss attributable to commodity derivative instruments into earnings, $17.5 million as an increase in operating costs and expenses and $23.3 million as a decrease 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 Hedging Instruments	Gain/(Loss) Recognized in Income on Derivative		
	Amount		Location
	For the Three Months Ended March 31,		
	2010	2009	
Commodity derivatives	$ 3.9	$ 24.3	Revenue
Commodity derivatives	(1.5)	--	Operating costs and expenses
Foreign currency derivatives	--	(0.1)	Other, net
Total	$ 2.4	$ 24.2	

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 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 derivatives are based on observable price quotes for similar products and locations. The value of our interest rate derivatives are valued by using appropriate financial models with the implied forward London Interbank Offered Rate yield curve for the same period as the future interest swap settlements.

§ Level 3 fair values are based on unobservable inputs. Unobservable inputs are used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Unobservable inputs reflect the reporting entity's own ideas about the assumptions that market participants would use in pricing an asset or liability (including assumptions about risk). Unobservable inputs are based on the best information available in the circumstances, which might include the reporting entity's internally developed data. The reporting entity must not ignore information about market participant assumptions that is reasonably available without undue cost and effort. Level 3 inpu ts are typically used in connection with internally developed valuation methodologies where management makes its best estimate of an instrument's fair value. Our Level 3 fair values largely consist of ethane, normal butane and natural gasoline-based contracts with a range of two to 12 months in term. We rely on price quotes from reputable brokers in the marketplace 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, combined with our forward transactions, are used in our model 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 measured on a recurring basis at March 31, 2010. These financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value assets and liabilities, in addition to their placement within the fair value hierarchy levels. There were no significant transfers between levels during the three months ended March 31, 2010.

	At March 31, 2010			
	Level 1	Level 2	Level 3	Total
Financial assets:				
Interest rate derivative instruments	$ --	$ 64.2	$ --	$ 64.2
Commodity derivative instruments	30.2	33.8	31.2	95.2
Total	$ 30.2	$ 98.0	$ 31.2	$ 159.4
Financial liabilities:				
Interest rate derivative instruments	$ --	$ 3.9	$ --	$ 3.9
Commodity derivative instruments	64.8	41.6	33.8	140.2
Total	$ 64.8	$ 45.5	$ 33.8	$ 144.1

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

	For the Three Months Ended March 31,	
	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

(1) There were $0.5 million of unrealized gains and $0.2 million of unrealized losses included in these amounts for the three months ended March 31, 2010 and 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 three months ended March 31, 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 segment assets and recorded, in operating costs and expenses, non-cash impairment charges of $1.5 million during the three months ended March 31, 2010.

Note 5. Inventories

Our inventory amounts were as follows at the dates indicated:

	March 31, 2010	December 31, 2009
Working inventory (1)	$ 702.8	$ 466.4
Forward sales inventory (2)	288.1	245.5
Total inventory	$ 990.9	$ 711.9

(1) Working inventory is comprised of inventories 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.
(2) Forward sales inventory consists of identified natural gas, NGL, refined product and crude oil volumes dedicated to the fulfillment of forward sales contracts.

In those instances where we take ownership of inventory volumes 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") adjustment amounts for the periods indicated:

	For the Three Months Ended March 31,	
	2010	2009
Cost of sales (1)	$ 7,342.3	$ 3,817.9
LCM adjustments	5.7	4.3

(1) Cost of sales is included in "Operating costs and expenses," as presented on our Unaudited Condensed Statements of Consolidated Operations. The fluctuation in this amount quarter-to-quarter is 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 accumulated depreciation balances were as follows at the dates indicated:

	Estimated Useful Life in Years	March 31, 2010	December 31, 2009
Plants and pipelines (1)	3-45 (5)	$ 18,077.8	$ 17,681.9
Underground and other storage facilities (2)	5-40 (6)	1,294.6	1,280.5
Platforms and facilities (3)	20-31	637.6	637.6
Transportation equipment (4)	3-10	61.2	60.1
Marine vessels	15-30	559.0	559.4
Land		82.9	82.9
Construction in progress		1,021.8	1,207.2
Total		21,734.9	21,509.6
Less accumulated depreciation		3,999.6	3,820.4
Property, plant and equipment, net		$ 17,735.3	$ 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.

(4) Transportation equipment includes vehicles and similar assets used in our operations.

(5) In general, the estimated useful lives of major components of this category are as follows: processing plants, 20-35 years; pipelines and related equipment, 5-45 years; terminal facilities, 10-35 years; delivery facilities, 20-40 years; office furniture and equipment, 3-20 years; buildings, 20-40 years; and laboratory and shop equipment, 5-35 years.

(6) In general, the estimated useful lives of major components of this category are as follows: underground storage facilities, 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 March 31,	
	2010	2009
Depreciation expense (1)	$ 180.3	$ 158.6
Capitalized interest (2)	10.5	17.4

(1) Depreciation expense is a component of “Costs and expenses” as presented in our Unaudited Condensed Statements of Consolidated Operations.

(2) Capitalized interest increases the carrying value of the associated asset and reduces interest expense during the period it is recorded.

Asset Retirement Obligations

We have recorded 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	4.2
Accretion expense	1.0
ARO liability balance, March 31, 2010	$ 60.0

Property, plant and equipment at March 31, 2010 and December 31, 2009 includes $27.8 million and $26.7 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset. The following table presents forecasted accretion expense associated with our AROs for the periods indicated:

Remainder of 2010	**2011**	**2012**	**2013**	**2014**
$ 2.8	$ 3.7	$ 4.0	$ 4.3	$ 4.7

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

Note 7. Investments in Unconsolidated Affiliates

We own interests in a number of related businesses that are accounted for using the equity method of accounting. We group our investments in unconsolidated affiliates according to the business segment to which they relate (see Note 11 for a general discussion of our business segments). The following table shows our ownership interest and investments in unconsolidated affiliates by business segment at the dates indicated:

	Ownership Interest at March 31, 2010	March 31, 2010	December 31, 2009
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C.	13.1%	$ 31.6	$ 32.6
K/D/S Promix, L.L.C. (“Promix”)	50%	50.1	48.9
Baton Rouge Fractionators LLC	32.2%	22.5	22.2
Skelly-Belvieu Pipeline Company, L.L.C.	50%	34.5	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%	177.2	178.5
Offshore Pipelines & Services:			
Poseidon Oil Pipeline Company, L.L.C. (“Poseidon”)	36%	61.0	61.7
Cameron Highway Oil Pipeline Company (“Cameron Highway”)	50%	237.5	239.6
Deepwater Gateway, L.L.C.	50%	100.7	101.8
Neptune Pipeline Company, L.L.C.	25.7%	55.6	53.8
Petrochemical & Refined Products Services:			
Baton Rouge Propylene Concentrator, LLC	30%	11.1	11.1
Centennial Pipeline LLC (“Centennial”)	50%	65.6	66.7
Other (2)	Various	3.7	3.8
Total		$ 883.5	$ 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 summarizes the unamortized excess cost amounts by business segment at the dates indicated:

	March 31, 2010	December 31, 2009
NGL Pipelines & Services	$ 26.4	$ 27.1
Onshore Crude Oil Pipelines & Services	20.2	20.4
Offshore Pipelines & Services	17.0	17.3
Petrochemical & Refined Products Services	3.3	4.0
Total	$ 66.9	$ 68.8

Such excess cost amounts were attributable to the underlying tangible and amortizable intangible assets of certain unconsolidated affiliates. We amortize such 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 March 31,	
	2010	2009
NGL Pipelines & Services	$ 0.2	$ 0.2
Onshore Crude Oil Pipelines & Services	0.2	0.2
Offshore Pipelines & Services	0.3	0.3
Petrochemical & Refined Products Services	0.7	1.3
Total	$ 1.4	$ 2.0

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

	For the Three Months Ended March 31,	
	2010	2009
NGL Pipelines & Services	$ 3.3	$ 1.2
Onshore Natural Gas Pipelines & Services	1.3	1.1
Onshore Crude Oil Pipelines & Services	2.3	3.3
Offshore Pipelines & Services	11.8	4.7
Petrochemical & Refined Products Services	(2.7)	(2.9)
Total	$ 16.0	$ 7.4

NGL Pipelines & Services

At March 31, 2010, our investees included in our NGL Pipelines & Services segment owned: (i) a natural gas processing facility and related assets located in south Louisiana, (ii) an NGL fractionation facility and related storage and pipeline assets located in south Louisiana, (iii) an NGL fractionation facility located in south Louisiana and (iv) a 572-mile pipeline that transports mixed NGLs to markets in southeast Texas.

Onshore Natural Gas Pipelines & Services

At March 31, 2010, our investees included in our Onshore Natural Gas Pipelines & Services segment owned: (i) a natural gas pipeline located in south Louisiana and (ii) a natural gas hub located in northwest Colorado.

Onshore Crude Oil Pipelines & Services

At March 31, 2010, our investee included in our Onshore Crude Oil Pipelines & Services segment owned a pipeline that transports crude oil from a marine terminal located in Freeport, Texas, to Cushing, Oklahoma, and from a marine terminal located in Texas City, Texas, to refineries in the Texas City and Houston, Texas areas.

Offshore Pipelines & Services

At March 31, 2010, our investees included in our Offshore Pipelines & Services segment owned: (i) a crude oil pipeline that gathers production from the outer continental shelf and deepwater areas of the Gulf of Mexico for delivery to onshore locations in south Louisiana, (ii) a crude oil pipeline that gathers production from deepwater areas of the Gulf of Mexico, primarily the South Green Canyon area, for delivery to refineries and terminals in southeast Texas, (iii) a crude oil and natural gas platform that processes production from the Marco Polo, K2, K2 North and Genghis Khan fields located in the South

Green Canyon area of the Gulf of Mexico and (iv) natural gas pipeline systems located in the Gulf of Mexico.

Petrochemical & Refined Products Services

At March 31, 2010, our investees included in our Petrochemical & Refined Products Services segment owned: (i) a propylene fractionation facility located in south Louisiana, (ii) a propylene pipeline extending from Mont Belvieu, Texas to La Porte, Texas and (iii) an interstate refined products pipeline extending from the upper Texas Gulf Coast to central Illinois that effectively loops our refined products pipeline system providing incremental transportation capacity into Mid-continent markets.

Summarized Income Statement Information of Unconsolidated Affiliates

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

	Summarized Income Statement Information for the Three Months Ended					
	March 31, 2010			March 31, 2009		
	Revenues	Operating Income	Net Income (Loss)	Revenues	Operating Income	Net Income
NGL Pipelines & Services	$ 74.8	$ 13.1	$ 13.0	$ 55.6	$ 5.0	$ 5.1
Onshore Natural Gas Pipelines & Services	42.3	2.5	2.4	38.3	2.1	2.2
Onshore Crude Oil Pipelines & Services	18.5	7.3	7.3	19.7	8.7	8.7
Offshore Pipelines & Services	55.0	29.2	28.7	29.4	1.1	0.5
Petrochemical & Refined Products Services	8.6	0.6	(0.3)	14.9	3.7	1.0

Note 8. Intangible Assets and Goodwill

Identifiable Intangible Assets

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

	March 31, 2010			December 31, 2009		
	Gross Value	Accum. Amort.	Carrying Value	Gross Value	Accum. Amort.	Carrying Value
NGL Pipelines & Services:						
Customer relationship intangibles	$ 237.4	$ (90.6)	$ 146.8	$ 237.4	$ (86.5)	$ 150.9
Contract-based intangibles	321.4	(161.9)	159.5	321.4	(156.7)	164.7
Segment total	558.8	(252.5)	306.3	558.8	(243.2)	315.6
Onshore Natural Gas Pipelines & Services:						
Customer relationship intangibles	372.0	(129.3)	242.7	372.0	(124.3)	247.7
Contract-based intangibles	565.3	(295.0)	270.3	565.3	(285.8)	279.5
Segment total	937.3	(424.3)	513.0	937.3	(410.1)	527.2
Onshore Crude Oil Pipelines & Services:						
Contract-based intangibles	10.0	(3.6)	6.4	10.0	(3.5)	6.5
Segment total	10.0	(3.6)	6.4	10.0	(3.5)	6.5
Offshore Pipelines & Services:						
Customer relationship intangibles	205.8	(108.6)	97.2	205.8	(105.3)	100.5
Contract-based intangibles	1.2	(0.3)	0.9	1.2	(0.2)	1.0
Segment total	207.0	(108.9)	98.1	207.0	(105.5)	101.5
Petrochemical & Refined Products Services:						
Customer relationship intangibles	104.6	(20.1)	84.5	104.6	(18.8)	85.8
Contract-based intangibles	42.1	(15.2)	26.9	42.1	(13.9)	28.2
Segment total	146.7	(35.3)	111.4	146.7	(32.7)	114.0
Total all segments	$ 1,859.8	$ (824.6)	$ 1,035.2	$ 1,859.8	$ (795.0)	$ 1,064.8

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

	For the Three Months Ended March 31,	
	2010	2009
NGL Pipelines & Services	$ 9.3	$ 9.8
Onshore Natural Gas Pipelines & Services	14.2	14.6
Onshore Crude Oil Pipelines & Services	0.1	0.1
Offshore Pipelines & Services	3.4	3.9
Petrochemical & Refined Products Services	2.6	2.7
Total	$ 29.6	$ 31.1

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

Remainder of 2010	2011	2012	2013	2014
$ 85.1	$ 105.7	$ 70.0	$ 81.9	$ 76.5

In general, our intangible assets fall within two categories – customer relationship 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, as appropriate.

Customer relationship intangible assets. 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 now have regular contact with them 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 March 31, 2010, the carrying value of our customer relationship intangible assets was $571.2 milli on.

Effective January 1, 2010, upon review of the amortization rate estimates established for our Val Verde customer relationship intangible assets, management reduced the amortization period to a gross life of 20 years through 2021. This change in estimate did not result in a material decrease in net income or earnings per unit for the three months ended March 31, 2010.

Contract-based intangible assets. Contract-based intangible assets represent specific commercial rights we acquired in connection with business combinations or asset purchases. At March 31, 2010, the carrying value of our contract-based intangible assets was $464.0 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.

Our goodwill impairment testing involves the determination of the fair value of a reporting unit, which is predicated based on our assumptions regarding the future economic prospects of the reporting unit. Such assumptions include (i) discrete financial forecasts for the assets contained within the reporting unit, which rely on management's estimates of operating margins and transportation volumes; (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 testing, each reporting unit's fair value was substantially in excess (a minimum of 10%) of its carrying value.

There have been no changes in our goodwill amounts since those reported in our 2009 Form 10-K.

Note 9. Debt Obligations

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

	March 31, 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 (1)	500.0	500.0
Senior Notes L, 6.30% fixed-rate, due September 2017	800.0	800.0
Senior Notes M, 5.65% fixed-rate, due April 2013	400.0	400.0
Senior Notes N, 6.50% fixed-rate, due January 2019	700.0	700.0
Senior Notes O, 9.75% fixed-rate, due January 2014	500.0	500.0
Senior Notes P, 4.60% fixed-rate, due August 2012	500.0	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
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)	175.0	175.0
DEP Term Loan, variable-rate, due December 2011	282.3	282.3
Total principal amount of senior debt obligations	9,514.8	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	11,047.5	11,297.0
Other, non-principal amounts:		
Change in fair value of debt-related derivative instruments (see Note 4)	41.2	44.4
Unamortized discounts, net of premiums	(18.4)	(18.7)
Unamortized deferred net gains related to terminated interest rate swaps (see Note 4)	20.4	23.7
Total other, non-principal amounts	43.2	49.4
Less current maturities of debt (2)	(175.0)	--
Total long-term debt	$ 10,915.7	$ 11,346.4

(1) Long-term and current maturities of debt reflect the classification of such obligations at March 31, 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 and K.
(2) Reflects Duncan Energy Partners' classification of debt at March 31, 2010.

Letters of Credit

At March 31, 2010, EPO had a $58.3 million letter of credit outstanding related to its Petal GO Zone Bonds. This letter of credit facility does not reduce the amount available for borrowing under EPO's credit facilities.

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 TEPPCO's debt obligations. If EPO were to default on any of its guaranteed debt, Enterprise Products Partners L.P. would be responsible for full repayment of that obligation.

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.

Debt Obligations

Apart from that discussed below, 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 on March 1, 2010 and was repaid.

Covenants

We were in compliance with the financial covenants of our consolidated debt agreements at March 31, 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 three months ended March 31, 2010:

	Range of Interest Rates Paid	Weighted-Average Interest Rate Paid
EPO Multi-Year Revolving Credit Facility	0.73% to 3.25%	0.75%
DEP Revolving Credit Facility	0.80% to 0.86%	0.83%
DEP Term Loan	0.93%	0.93%
Petal GO Zone Bonds	0.12% to 0.29%	0.18%

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	Remainder of 2010	2011	2012	2013	2014	After 2014
Revolving Credit Facilities	$ 175.0	$ --	$ 175.0	$ --	$ --	$ --	$ --
Senior Notes	9,000.0	500.0	450.0	1,000.0	1,200.0	1,150.0	4,700.0
Term Loans	282.3	--	282.3	--	--	--	--
Junior Subordinated Notes	1,532.7	--	--	--	--	--	1,532.7
Other	57.5	--	--	--	--	--	57.5
Total	$ 11,047.5	$ 500.0	$ 907.3	$ 1,000.0	$ 1,200.0	$ 1,150.0	$ 6,290.2

Long-term and current maturities of debt reflect the classification of such obligations at March 31, 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) and Senior Notes K ($500.0 million due in June 2010).

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 March 31, 2010, (ii) the total debt of each unconsolidated affiliate at March 31, 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%	117.7	6.8	9.0	8.9	8.6	8.6	75.8
Total		$ 220.4	$ 10.0	$ 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 March 31, 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 10. 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 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 percentage 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 36,175,679 common units have been issued under the DRIP registration statement through March 31, 2010.

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 871,169 common units have been issued to employees under this plan through March 31, 2010.

We have also filed a universal shelf registration statement with the SEC that allows us to issue an unlimited amount of debt and equity securities. We have issued 29,852,500 common units in underwritten offerings under this registration statement generating $795.3 million of net cash proceeds through March

31, 2010. In addition, we have issued $4.0 billion of senior notes under this registration statement through March 31, 2010.

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 net cash proceeds of $343.3 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. See Note 18 for additional information.

The following table reflects the number of common units issued and the net cash proceeds received from underwritten and other common unit offerings completed during the three months ended March 31, 2010:

	Number of Common Units Issued	Net Cash Proceeds from Issuance of Common Units: 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
Total 2010	13,759,584	$ 428.3	$ 8.8	$ 437.1

Net cash proceeds received from our DRIP and EUPP were also 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 regular quarterly cash distributions for the first 16 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 16th 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 our outstanding units 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 offering	10,925,000	--	--	--
Common units issued in connection with DRIP and EUPP	2,834,584	--	--	--
Common units issued in connection with equity awards	20,092	--	--	--
Restricted units issued	--	1,290,075	--	--
Forfeiture of restricted units	--	(50,548)	--	--
Conversion of restricted units to common units	34,528	(34,528)	--	--
Acquisition of treasury units	(7,480)	--	--	7,480
Cancellation of treasury units	--	--	--	(7,480)
Other	(61)	--	--	--
Balance, March 31, 2010	617,009,491	3,925,881	4,520,431	--

Summary of Changes in Limited Partners' Equity

The following table details the 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	315.8	1.6	--	317.4
Operating lease expenses paid by EPCO	0.2	--	--	0.2
Cash distributions paid to partners	(344.0)	(1.5)	--	(345.5)
Unit option reimbursements to EPCO	(0.9)	--	--	(0.9)
Net cash proceeds from issuance of common units	428.3	--	--	428.3
Cash proceeds from exercise of unit options	0.6	--	--	0.6
Amortization of equity awards	1.9	6.1	--	8.0
Acquisition of treasury units	--	(0.2)	--	(0.2)
Balance, March 31, 2010	$ 9,575.4	$ 43.7	$ 118.5	$ 9,737.6

Distributions to Partners

We paid EPGP incentive distributions of $53.9 million and $35.2 million during the three months ended March 31, 2010 and 2009, respectively.

The following table presents our declared quarterly cash distribution rates per common unit since the first quarter of 2008 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
2008			
1st Quarter	$0.5075	Apr. 30, 2008	May 7, 2008
2nd Quarter	$0.5150	Jul. 31, 2008	Aug. 7, 2008
3rd Quarter	$0.5225	Oct. 31, 2008	Nov. 12, 2008
4th Quarter	$0.5300	Jan. 30, 2009	Feb. 9, 2009
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

Accumulated Other Comprehensive Income (Loss)

AOCI primarily includes the effective portion of the gain or loss on derivative instruments designated and qualified as a cash flow hedge, foreign currency adjustments and minimum pension liability adjustments. Amounts accumulated in OCI from cash flow hedges are reclassified into earnings in the same period(s) in which the hedged forecasted transactions (such as a forecasted forward sale of NGLs) affect earnings. If it becomes probable that the forecasted transaction will not occur, the net gain or loss in AOCI must be immediately reclassified.

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

	March 31, 2010	December 31, 2009
Commodity derivative instruments (1)	$ (41.9)	$ 0.5
Interest rate derivative instruments (1)	(14.9)	(12.5)
Foreign currency derivative instruments (1)	--	0.4
Foreign currency translation adjustment (2)	1.4	0.8
Pension and postretirement benefit plans	(1.7)	(0.8)
Subtotal	(57.1)	(11.6)
Amount attributable to noncontrolling interest	2.5	3.2
Total AOCI in partners' equity	$ (54.6)	$ (8.4)

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

Noncontrolling Interest

Prior to the completion of the TEPPCO Merger, effective October 26, 2009, we accounted for the former owners' interest in TEPPCO and TEPPCO GP as noncontrolling interest. 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. In addition, the former owners' share of the net assets of TEPPCO and TEPPCO GP are presented as noncontrolling interest, a component of equity, on our Unaudited Condensed Consolidated Balance Sheets.

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

	March 31, 2010	December 31, 2009
Limited partners of Duncan Energy Partners:		
Third-party owners of Duncan Energy Partners (1)	$ 412.7	$ 414.3
Related party owners of Duncan Energy Partners	1.7	1.7
Joint venture partners (2)	118.0	117.4
AOCI attributable to noncontrolling interest	(2.5)	(3.2)
Total	$ 529.9	$ 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 interest as presented on our Unaudited Condensed Statements of Consolidated Operations for the periods indicated:

	For the Three Months Ended March 31, 2010	For the Three Months Ended March 31, 2009
Former owners of TEPPCO	$ --	$ 78.3
Limited partners of Duncan Energy Partners	8.7	5.1
Joint venture partners	7.3	6.8
Total	$ 16.0	$ 90.2

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 Three Months Ended March 31,	
	2010	2009
Cash distributions paid to noncontrolling interest:		
Limited partners of TEPPCO	$ --	$ 91.4
Limited partners of Duncan Energy Partners	10.6	6.4
Joint venture partners	6.8	7.7
Total cash distributions paid to noncontrolling interest	$ 17.4	$ 105.5
Cash contributions from noncontrolling interest:		
Limited partners of TEPPCO	$ --	$ 1.6
Limited partners of Duncan Energy Partners	0.2	--
Joint venture partners	--	(2.2)
Total cash contributions from noncontrolling interest	$ 0.2	$ (0.6)

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) primarily represent the quarterly cash distributions paid by these entities to their unitholders. Cash contributions from the limited partners of Duncan Energy Partners and TEPPCO (prior to the completion of the TEPPCO Merger on October 26, 2009) primarily represent proceeds each entity received from the issuance of units.

Note 11. Business Segments

We have five reportable business segments: NGL Pipelines & Services, Onshore Natural Gas Pipelines & Services, Onshore Crude Oil Pipelines & Services, Offshore Pipelines & Services and 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.< /font>

We define total segment gross operating margin as operating income before: (i) depreciation, amortization and accretion expense; (ii) non-cash consolidated asset impairment charges; (iii) operating lease expenses for which we do not have the payment obligation; (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 consolidation. 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 100% of 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 March 31, 2010	2009
Revenues	$ 8,544.5	$ 4,886.9
Less: Operating costs and expenses	(7,971.9)	(4,376.6)
Add: Equity in income of unconsolidated affiliates	16.0	7.4
Depreciation, amortization and accretion in operating costs and expenses (1)	212.4	196.4
Non-cash impairment charges	1.5	--
Operating lease expenses paid by EPCO	0.2	0.2
Gain from asset sales and related transactions in operating costs and expenses (2)	(7.3)	(0.2)
Total segment gross operating margin	$ 795.4	$ 714.1

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

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

	For the Three Months Ended March 31, 2010	2009
Total segment gross operating margin	$ 795.4	$ 714.1
Adjustments to reconcile total segment gross operating margin to operating income:		
Depreciation, amortization and accretion in operating costs and expenses	(212.4)	(196.4)
Non-cash impairment charges	(1.5)	--
Operating lease expenses paid by EPCO	(0.2)	(0.2)
Gain from asset sales and related transactions in operating costs and expenses	7.3	0.2
General and administrative costs	(37.6)	(34.9)
Operating income	551.0	482.8
Other expense, net	(148.5)	(151.3)
Income before provision for income taxes	$ 402.5	$ 331.5

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 March 31, 2010	$ 3,666.3	$ 1,111.1	$ 2,386.7	$ 86.5	$ 1,061.5	$ --	$ 8,312.1
Three months ended March 31, 2009	2,266.9	667.7	1,269.7	68.5	394.6	--	4,667.4
Revenues from related parties:							
Three months ended March 31, 2010	180.0	50.4	(0.1)	2.1	--	--	232.4
Three months ended March 31, 2009	153.5	65.8	0.2	--	--	--	219.5
Intersegment and intrasegment revenues:							
Three months ended March 31, 2010	2,547.2	215.6	24.7	0.4	257.8	(3,045.7)	--
Three months ended March 31, 2009	1,387.9	153.7	8.2	0.3	116.2	(1,666.3)	--
Total revenues:							
Three months ended March 31, 2010	6,393.5	1,377.1	2,411.3	89.0	1,319.3	(3,045.7)	8,544.5
Three months ended March 31, 2009	3,808.3	887.2	1,278.1	68.8	510.8	(1,666.3)	4,886.9
Equity in income (loss) of unconsolidated affiliates:							
Three months ended March 31, 2010	3.3	1.3	2.3	11.8	(2.7)	--	16.0
Three months ended March 31, 2009	1.2	1.1	3.3	4.7	(2.9)	--	7.4
Gross operating margin:							
Three months ended March 31, 2010	437.3	130.3	26.7	81.1	120.0	--	795.4
Three months ended March 31, 2009	350.9	161.9	50.5	61.3	89.5	--	714.1
Segment assets:							
At March 31, 2010	7,257.4	6,863.8	861.7	2,097.8	3,569.8	1,021.8	21,672.3
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 March 31, 2010	6,471.2	6,033.5	375.1	1,462.8	2,370.9	1,021.8	17,735.3
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 March 31, 2010	138.7	32.4	177.2	454.8	80.4	--	883.5
At December 31, 2009	141.6	32.0	178.5	456.9	81.6	--	890.6
Intangible assets, net: (see Note 8)							
At March 31, 2010	306.3	513.0	6.4	98.1	111.4	--	1,035.2
At December 31, 2009	315.6	527.2	6.5	101.5	114.0	--	1,064.8
Goodwill: (see Note 8)							
At March 31, 2010	341.2	284.9	303.0	82.1	1,007.1	--	2,018.3
At December 31, 2009	341.2	284.9	303.0	82.1	1,007.1	--	2,018.3

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

	For the Three Months Ended March 31,	
	2010	2009
NGL Pipelines & Services:		
Sales of NGLs	$ 3,664.1	$ 2,252.2
Sales of other petroleum and related products	0.5	0.5
Midstream services	181.7	167.7
Total	3,846.3	2,420.4
Onshore Natural Gas Pipelines & Services:		
Sales of natural gas	975.2	556.6
Midstream services	186.3	176.9
Total	1,161.5	733.5
Onshore Crude Oil Pipelines & Services:		
Sales of crude oil	2,367.3	1,245.8
Midstream services	19.3	24.1
Total	2,386.6	1,269.9
Offshore Pipelines & Services:		
Sales of natural gas	0.4	0.3
Sales of crude oil	2.1	0.2
Midstream services	86.1	68.0
Total	88.6	68.5
Petrochemical & Refined Products Services:		
Sales of other petroleum and related products	932.6	261.5
Midstream services	128.9	133.1
Total	1,061.5	394.6
Total consolidated revenues	$ 8,544.5	$ 4,886.9
Consolidated costs and expenses		
Operating costs and expenses:		
Cost of sales for our marketing activities	$ 6,649.2	$ 3,403.3
Depreciation, amortization and accretion	212.4	196.4
Gain from asset sales and related transactions	(7.3)	(0.2)
Non-cash impairment charges	1.5	--
Other operating costs and expenses	1,116.1	777.1
General and administrative costs	37.6	34.9
Total consolidated costs and expenses	$ 8,009.5	$ 4,411.5

The following table reconciles total revenues and total gross operating margin for the three months ended March 31, 2009, as currently presented, with those we previously presented:

Total revenues, as previously reported	$	3,423.1
Revenues from TEPPCO		1,457.5
Revenues from Jonah Gas Gathering Company ("Jonah") (1)		59.4
Eliminations (2)		(53.1)
Total revenues, as currently reported	$	4,886.9
Total segment gross operating margin, as previously reported	$	548.7
Gross operating margin from TEPPCO		151.2
Gross operating margin from Jonah		45.3
Eliminations (3)		(31.1)
Total segment gross operating margin, as currently reported	$	714.1

(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.
(2) Represents the elimination of revenues between Enterprise Products Partners, TEPPCO and Jonah.
(3) Represents the elimination of equity earnings from Jonah recorded by Enterprise Products Partners and TEPPCO prior to the merger.

Note 12. Related Party Transactions

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

	For the Three Months Ended March 31,	
	2010	2009
Revenues – related parties:		
Energy Transfer Equity and subsidiaries	$ 186.6	$ 162.8
Unconsolidated affiliates	45.8	56.7
Total revenue – related parties	$ 232.4	$ 219.5
Costs and expenses – related parties:		
EPCO and affiliates	$ 158.4	$ 143.8
Energy Transfer Equity and subsidiaries	176.9	91.4
Unconsolidated affiliates	12.2	6.9
Other	--	14.4
Total costs and expenses – related parties	$ 347.5	$ 256.5

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

	March 31, 2010	December 31, 2009
Accounts receivable - related parties:		
EPCO and affiliates	$ 0.3	$ --
Energy Transfer Equity and subsidiaries	11.3	28.2
Other	15.3	10.2
Total accounts receivable – related parties	$ 26.9	$ 38.4
Accounts payable - related parties:		
EPCO and affiliates	$ 2.1	$ 26.8
Energy Transfer Equity and subsidiaries	37.5	33.4
Other	8.2	9.6
Total accounts payable – related parties	$ 47.8	$ 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 March 31, 2010, EPCO and its affiliates (including Dan Duncan LLC and two Duncan family trusts the beneficiaries of which include the estate of Dan L. Duncan) beneficially owned interests in the following entities:

	Number of Units	Percentage of Outstanding Units
Enterprise Products Partners (1) (2)	195,882,296	31.3%
Enterprise GP Holdings (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) An affiliate of EPCO, Dan Duncan LLC, which is controlled by the DD LLC Trustees, who are currently the same individuals as the EPCO Trustees and the independent co-executors of the estate of Dan L. Duncan, also owns 100% of the general partner of Enterprise GP Holdings, EPE 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 received by EPGP for the periods indicated:

	For the Three Months Ended March 31, 2010	For the Three Months Ended March 31, 2009
General partner distributions	$ 7.0	$ 4.9
Incentive distributions	53.9	35.2
Total distributions	$ 60.9	$ 40.1

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 Three Months Ended March 31, 2010	For the Three Months Ended March 31, 2009
Enterprise Products Partners	$ 82.9	$ 74.9
Enterprise GP Holdings	57.3	43.2
Total distributions	$ 140.2	$ 118.1

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 in respect of 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.

Under the ASA, EPCO subleases to us (for $1 per year) certain equipment which it holds pursuant to operating leases and has assigned to us its purchase option under such leases (the “retained leases”). EPCO remains liable for the actual cash lease payments associated with these 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 compensation of employees. We reimburse EPCO for actual direct and indirect expenses it incurs related to the operation of our assets. Likewise, our general and administrative costs include amounts paid to EPCO for administrative services, including 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 general 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 March 31,	
	2010	2009
Operating costs and expenses	$ 134.4	$ 117.8
General and administrative expenses	24.0	26.0
Total costs and expenses	$ 158.4	$ 143.8

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"), 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. 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 perform supporting or complementary roles to our other business operations. Since we and our affiliates hold ownership interests in these entities and directly or indirectly benefit from our related party transactions with such entities, they are presented here. The following information summarizes significant related party transactions with our current 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 $37.8 million and $53.6 million for the three months ended March 31, 2010 and 2009, 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 $2.7 million for the three months ended March 31, 2010 and 2009, respectively. Expenses with Promix were $8.6 million and $4.5 million for the three months ended March 31, 2010 and 2009, respectively.

§ We paid $2.6 million and $1.7 million to Centennial for the three months ended March 31, 2010 and 2009 for other pipeline transportation services, respectively.

§ For the three months ended March 31, 2010 and 2009, we paid Seaway $1.1 million and $1.8 million, respectively, for transportation and tank rentals in connection with our crude oil marketing activities.

§ We perform management services for certain of our unconsolidated affiliates. We charged such affiliates $2.9 million and $2.6 million for the three months ended March 31, 2010 and 2009, respectively.

Relationship with Duncan Energy Partners

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

At March 31, 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 March 31, 2010, EPO owned 58.6% 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 13. 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, 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 value 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 the net income available to EPGP for the periods indicated:

	For the Three Months Ended March 31,	
	2010	2009
Net income attributable to Enterprise Products Partners L.P.	$ 377.8	$ 225.3
Less incentive earnings allocations to EPGP	(53.9)	(35.2)
Net income available after incentive earnings allocation	323.9	190.1
Multiplied by EPGP ownership interest	2.0%	2.0%
Standard earnings allocation to EPGP	$ 6.5	$ 3.8
Incentive earnings allocation to EPGP	$ 53.9	$ 35.2
Standard earnings allocation to EPGP	6.5	3.8
Net income available to EPGP	60.4	39.0
Adjustment for master limited partnerships (1)	2.9	1.4
Net income available to EPGP for EPU purposes	$ 63.3	$ 40.4

(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 March 31,	
	2010	2009
BASIC EARNINGS PER UNIT		
Numerator		
Net income attributable to Enterprise Products Partners L.P.	$ 377.8	$ 225.3
Net income available to EPGP for EPU purposes	(63.3)	(40.4)
Net income available to limited partners	$ 314.5	$ 184.9
Denominator		
Weighted – average common units	614.6	450.7
Weighted – average time-vested restricted units	3.2	2.0
Total	617.8	452.7
Basic earnings per unit		
Net income per unit before EPGP earnings allocation	$ 0.61	$ 0.50
Net income available to EPGP	(0.10)	(0.09)
Net income available to limited partners	$ 0.51	$ 0.41
DILUTED EARNINGS PER UNIT		
Numerator		
Net income attributable to Enterprise Products Partners L.P.	$ 377.8	$ 225.3
Net income available to EPGP for EPU purposes	(63.3)	(40.4)
Net income available to limited partners	$ 314.5	$ 184.9
Denominator		
Weighted – average common units	614.6	450.7
Weighted – average time-vested restricted units	3.2	2.0
Class B units	4.5	--
Incremental option units	0.7	--
Total	623.0	452.7
Diluted earnings per unit		
Net income per unit before EPGP earnings allocation	$ 0.60	$ 0.50
Net income available to EPGP	(0.10)	(0.09)
Net income available to limited partners	$ 0.50	$ 0.41

Note 14. Commitments and Contingencies

Litigation

On occasion, we or our unconsolidated affiliates are named as defendants in litigation and legal proceedings relating to our normal business activities, including regulatory and environmental matters. Although we are insured against various risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings. We are not aware of any litigation, pending or threatened, that we believe is reasonably likely to have a significant adverse effect on our financial position, results of operations or cash flows.

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

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

The CDPHE, through its Air Pollution Control Division, has 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 of the Meeker Gas Processing Plant. The Compliance Order proposes an administrative fine of approximately $0.3 million and would require the Meeker Gas Processing Plant to be operated in compliance with the Colorado Act. We have entered into discussions regarding the terms of the Compliance Order.

In January 2009, the State of New Mexico filed suit in District Court in Santa Fe County, New Mexico, under the New Mexico Air Quality Control Act. The lawsuit arose out of a February 27, 2008 Notice Of Violation issued to Marathon Oil Corp. ("Marathon") as operator of the Indian Basin natural gas processing facility located in Eddy County, New Mexico. We own a 42.4% undivided interest in the assets comprising the Indian Basin facility. The State alleges violations of its air laws. Marathon agreed to a Consent Decree with the State which was approved by the District Court on December 21, 2009. Under the Decree, Marathon paid the State approximately $0.6 million, agreed to $4.5 million of additional environmental projects in New Mexico and agreed to two projects for "correc tive 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.

Regulatory Matters

Certain recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" and including carbon dioxide and methane, may be contributing to climate change. On June 26, 2009, the U.S. House of Representatives passed the "American Clean Energy and Security Act of 2009," or "ACESA," which would establish an economy-wide cap-and-trade program intended to reduce the emissions of greenhouse gases in the United States and would require most 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 work on its own legislation 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 presented an endangerment to human health and the environment. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. Although it may take the EPA several years to adopt and impose regulations limiting emissions of greenhouse gases, any such regulation could require us to incur costs to reduce emissions of greenhouse gases associated with our operations. Any laws or regulations that may be adopted to restrict or reduce emissi ons of greenhouse gases would likely require us to incur increased operating costs, and may have an adverse effect on our business, financial position, demand for our operations, results of operations and cash flows.

Contractual Obligations

Scheduled Maturities of Long-Term Debt. With the exception of routine fluctuations in the balance of our consolidated revolving credit facilities and the repayment of our Pascagoula MBFC Loan, there have been no significant changes in our consolidated scheduled maturities of long-term debt since those reported in our 2009 Form 10-K.

Operating Lease Obligations. Lease and rental expense included in costs and expenses was $16.4 million and $14.0 million during the three months ended March 31, 2010 and 2009, 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.

Commitments Under Equity Compensation Plans of EPCO

In accordance with our agreements with EPCO, we reimburse EPCO for our share of its compensation expense associated with certain employees who perform management, administrative and operating functions for us. See Note 3 for additional information regarding our accounting for equity awards.

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 March 31, 2010, claims against us totaled approximately $56.3 million. These matters are in various stages of assessment and the ultimate outcome of such disputes cannot be reasonably estimated. However, in our opinion, the likelihood of a material adverse outcome related to such disputes against us is remote. Accordingly, accruals for loss contingencies related to these matters that might result from the resolution of such disputes have not been reflected in our consolidated financial statements.

Centennial Guarantees

We have certain guarantee obligations in connection with our ownership interest in Centennial. We have guaranteed one-half of Centennial's debt obligations, which obligates us to an estimated payment of $58.9 million in the event of a default by Centennial. At March 31, 2010, we had a liability of $8.2 million representing the estimated fair value of our share of the Centennial debt guaranty.

In lieu of Centennial procuring insurance to satisfy third-party liabilities 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 ownership interest in Centennial) in the event of a catastrophic event. At March 31, 2010, we had a liability of $3.6 million representing the estimated fair value of our cash call guaranty. Cash contributions to Centennial under the limited cash call agreement may be covered by our insurance depending on the nature of the catastrophic event.

Note 15. 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 are customary and sufficient 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.

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 March 31,	
	2010	2009
Business interruption proceeds:		
Hurricane Ike	$ 1.1	$ --
Total business interruption proceeds	1.1	--
Property damage proceeds: (1)		
Hurricane Katrina	--	23.2
Hurricane Rita	26.8	--
Hurricane Ike	1.9	--
Total property damage proceeds	28.7	23.2
Total	$ 29.8	$ 23.2

(1) Our operating income for the three months ended March 31, 2010 and 2009 includes $7.6 million and $0.6 million, respectively, of proceeds from property damage insurance claims.

At March 31, 2010, we had $33.8 million of estimated property damage claims outstanding related to storms that we believe are probable of collection during the next twelve months. To the extent we estimate the dollar value of such damages, a change in our estimates may occur as additional information becomes available.

Note 16. Supplemental Cash Flow Information

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

	For the Three Months Ended March 31,	
	2010	2009
Decrease (increase) in:		
Accounts and notes receivable – trade	$ 43.4	$ 152.0
Accounts receivable – related party	11.9	11.9
Inventories	(279.1)	(157.0)
Prepaid and other current assets	(55.5)	11.6
Other assets	0.6	(33.8)
Increase (decrease) in:		
Accounts payable – trade	118.4	(15.9)
Accounts payable – related party	(21.9)	(10.6)
Accrued product payables	302.5	(85.2)
Accrued expenses	(29.3)	12.9
Accrued interest	(54.2)	(29.3)
Other current liabilities	40.6	(0.2)
Other liabilities	(3.3)	(2.2)
Net effect of changes in operating accounts	$ 74.1	$ (145.8)

Note 17. 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. 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 9 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.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Balance Sheet
March 31, 2010

	EPO and Subsidiaries						
ASSETS	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
Current assets:							
Cash and cash equivalents	$ 70.3	$ 68.8	$ (4.4)	$ 134.7	$ --	$ 0.2	$ 134.9
Restricted Cash	99.1	2.6	--	101.7	--	--	101.7
Accounts and notes receivable, net	758.7	2,370.8	(44.0)	3,085.5	(2.6)	--	3,082.9
Inventories	788.6	204.8	(2.5)	990.9	-	--	990.9
Prepaid and other current assets	195.3	108.6	(7.3)	296.6	0.2	--	296.8
Total current assets	1,912.0	2,755.6	(58.2)	4,609.4	(2.4)	0.2	4,607.2
Property, plant and equipment, net	1,429.7	16,315.8	(10.2)	17,735.3	--	--	17,735.3
Investments in unconsolidated affiliates	18,706.4	5,898.1	(23,721.0)	883.5	9,884.6	(9,884.6)	883.5
Intangible assets, net	165.8	884.7	(15.3)	1,035.2	--	--	1,035.2
Goodwill	473.7	1,544.6	--	2,018.3	--	--	2,018.3
Other assets	255.7	123.8	(158.9)	220.6	--	1.0	221.6
Total assets	$ 22,943.3	$ 27,522.6	$ (23,963.6)	$ 26,502.3	$ 9,882.2	$ (9,883.4)	$ 26,501.1
LIABILITIES AND EQUITY							
Current liabilities:							
Current maturities of debt	$ --	$ 183.9	$ (8.9)	$ 175.0	$ --	$ --	$ 175.0
Accounts payable	214.7	426.8	(174.8)	466.7	0.1	--	466.8
Accrued product payables	1,891.1	1,832.8	(28.8)	3,695.1	--	--	3,695.1
Other current liabilities	360.5	246.5	(3.3)	603.7	--	0.1	603.8
Total current liabilities	2,466.3	2,690.0	(215.8)	4,940.5	0.1	0.1	4,940.7
Long-term debt	10,521.9	393.8	--	10,915.7	--	--	10,915.7
Commitments and contingencies							
Other long-term liabilities	24.1	209.9	(1.3)	232.7	--	--	232.7
Equity:							
Controlling interests	9,931.0	20,717.5	(20,775.7)	9,872.8	9,882.1	(9,872.8)	9,882.1
Noncontrolling interests	--	3,511.4	(2,970.8)	540.6	--	(10.7)	529.9
Total equity	9,931.0	24,228.9	(23,746.5)	10,413.4	9,882.1	(9,883.5)	10,412.0
Total liabilities and equity	$ 22,943.3	$ 27,522.6	$ (23,963.6)	$ 26,502.3	$ 9,882.2	$ (9,883.4)	$ 26,501.1

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

	EPO and Subsidiaries						
ASSETS	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
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:							
Controlling interests	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 March 31, 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	$ 6,957.4	$ 4,613.0	$ (3,025.9)	$ 8,544.5	$ --	$ --	$ 8,544.5
Costs and expenses:							
Operating costs and expenses	6,846.1	4,152.3	(3,026.5)	7,971.9	--	--	7,971.9
General and administrative costs	--	35.6	--	35.6	2.0	--	37.6
Total costs and expenses	6,846.1	4,187.9	(3,026.5)	8,007.5	2.0	--	8,009.5
Equity in income of unconsolidated affiliates	413.7	53.5	(451.2)	16.0	379.8	(379.8)	16.0
Operating income	525.0	478.6	(450.6)	553.0	377.8	(379.8)	551.0
Other income (expense):							
Interest expense	(143.8)	(7.4)	2.6	(148.6)	--	--	(148.6)
Other, net	2.8	(0.1)	(2.6)	0.1	--	--	0.1
Total other expense, net	(141.0)	(7.5)	--	(148.5)	--	--	(148.5)
Income before provision for income taxes	384.0	471.1	(450.6)	404.5	377.8	(379.8)	402.5
Provision for income taxes	(4.9)	(3.8)	--	(8.7)	--	--	(8.7)
Net income	379.1	467.3	(450.6)	395.8	377.8	(379.8)	393.8
Net income attributable to noncontrolling interest	--	0.2	(16.3)	(16.1)	--	0.1	(16.0)
Net income attributable to entity	$ 379.1	$ 467.5	$ (466.9)	$ 379.7	$ 377.8	$ (379.7)	$ 377.8

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
Three Months Ended March 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
Revenues	$ 3,681.7	$ 2,858.2	$ (1,653.0)	$ 4,886.9	$ --	$ --	$ 4,886.9
Costs and expenses:							
Operating costs and expenses	3,580.1	2,448.7	(1,652.2)	4,376.6	--	--	4,376.6
General and administrative costs	1.9	31.0	--	32.9	2.0	--	34.9
Total costs and expenses	3,582.0	2,479.7	(1,652.2)	4,409.5	2.0	--	4,411.5
Equity in income of unconsolidated affiliates	244.2	55.4	(292.2)	7.4	227.3	(227.3)	7.4
Operating income	343.9	433.9	(293.0)	484.8	225.3	(227.3)	482.8
Other income (expense):							
Interest expense	(116.6)	(39.1)	3.2	(152.5)	--	--	(152.5)
Other, net	3.3	1.1	(3.2)	1.2	--	--	1.2
Total other expense, net	(113.3)	(38.0)	--	(151.3)	--	--	(151.3)
Income before provision for income taxes	230.6	395.9	(293.0)	333.5	225.3	(227.3)	331.5
Provision for income taxes	(3.3)	(12.7)	--	(16.0)	--	--	(16.0)
Net income	227.3	383.2	(293.0)	317.5	225.3	(227.3)	315.5
Net income attributable to noncontrolling interest	--	2.6	(92.8)	(90.2)	--	--	(90.2)
Net income attributable to entity	$ 227.3	$ 385.8	$ (385.8)	$ 227.3	$ 225.3	$ (227.3)	$ 225.3

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Cash Flows
Three Months Ended March 31, 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	$ 379.1	$ 467.3	$ (450.6)	$ 395.8	$ 377.8	$ (379.8)	$ 393.8
Adjustments to reconcile net income to cash provided by operating activities:							
Depreciation, accretion and amortization	21.5	196.4	(0.3)	217.6	--	--	217.6
Non-cash impairment charges	--	1.5	--	1.5	--	--	1.5
Equity in income of unconsolidated affiliates	(413.7)	(53.5)	451.2	(16.0)	(379.8)	379.8	(16.0)
Distributions received from unconsolidated affiliates	47.7	44.4	(61.9)	30.2	406.8	(406.8)	30.2
Operating lease expenses paid by EPCO	0.2	--	--	0.2	--	--	0.2
Gain from asset sales and related transactions	--	(7.5)	--	(7.5)	--	--	(7.5)
Deferred income tax expense	0.9	0.1	--	1.0	--	--	1.0
Changes in fair market value of derivative instruments	(9.6)	1.8	--	(7.8)	--	--	(7.8)
Effect of pension settlement recognition	--	(0.2)	--	(0.2)	--	--	(0.2)
Net effect of changes in operating accounts	435.7	(425.3)	61.7	72.1	2.1	(0.1)	74.1
Cash provided by operating activities	461.8	225.0	0.1	686.9	406.9	(406.9)	686.9
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(18.0)	(326.2)	--	(344.2)	--	--	(344.2)
Increase in restricted cash	(36.0)	(2.1)	--	(38.1)	--	--	(38.1)
Cash used for business combinations	(2.2)	--	--	(2.2)	--	--	(2.2)
Investments in unconsolidated affiliates	(84.8)	(7.4)	84.5	(7.7)	(437.1)	437.1	(7.7)
Repayment of loan to Duncan Energy Partners	(45.6)	45.6	--	--	--	--	--
Proceeds from asset sales and related transactions	--	21.7	--	21.7	--	--	21.7
Cash used in investing activities	(186.6)	(268.4)	84.5	(370.5)	(437.1)	437.1	(370.5)
Financing activities:							
Borrowings under debt agreements	330.4	15.1	--	345.5	--	--	345.5
Repayments of debt	(579.9)	(15.1)	--	(595.0)	--	--	(595.0)
Cash distributions paid to partners	(406.8)	(49.1)	49.1	(406.8)	(407.3)	406.8	(407.3)
Cash distributions paid to noncontrolling interest	--	(32.8)	15.3	(17.5)	--	0.1	(17.4)
Net cash proceeds from issuance of common units	--	--	--	--	437.7	--	437.7
Cash contributions from members	437.1	68.6	(68.6)	437.1	--	(437.1)	--
Cash contributions from noncontrolling interest	--	78.8	(78.6)	0.2	--	--	0.2
Other financing activities	(0.1)	--	--	(0.1)	(0.2)	--	(0.3)
Cash provided by (used in) financing activities	(219.3)	65.5	(82.8)	(236.6)	30.2	(30.2)	(236.6)
Effect of exchange rate changes on cash	--	0.4	--	0.4	--	--	0.4
Net change in cash and cash equivalents	55.9	22.1	1.8	79.8	--	--	79.8
Cash and cash equivalents, January 1	14.4	46.3	(6.2)	54.5	--	0.2	54.7
Cash and cash equivalents, March 31	$ 70.3	$ 68.8	$ (4.4)	$ 134.7	$ --	$ 0.2	$ 134.9

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Cash Flows
Three Months Ended March 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
Operating activities:							
Net income	$ 227.3	$ 383.2	$ (293.0)	$ 317.5	$ 225.3	$ (227.3)	$ 315.5
Adjustments to reconcile net income to cash provided by operating activities:							
Depreciation, accretion and amortization	18.1	180.9	0.1	199.1	--	--	199.1
Equity in income of unconsolidated affiliates	(244.2)	(55.4)	292.2	(7.4)	(227.3)	227.3	(7.4)
Distributions received from unconsolidated affiliates	29.3	60.4	(67.3)	22.4	287.6	(287.6)	22.4
Operating lease expenses paid by EPCO	0.2	--	--	0.2	--	--	0.2
Gain from asset sales and related transactions	--	(0.2)	--	(0.2)	--	--	(0.2)
Deferred income tax expense	0.3	0.7	--	1.0	--	(0.1)	0.9
Changes in fair market value of derivative instruments	(9.6)	(3.0)	--	(12.6)	--	--	(12.6)
Effect of pension settlement recognition	--	(0.1)	--	(0.1)	--	--	(0.1)
Net effect of changes in operating accounts	(19.8)	(252.3)	132.9	(139.2)	(6.1)	(0.5)	(145.8)
Cash provided by operating activities	1.6	314.2	64.9	380.7	279.5	(288.2)	372.0
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(37.1)	(470.4)	--	(507.5)	--	--	(507.5)
Increase in restricted cash	(40.7)	--	--	(40.7)	--	--	(40.7)
Acquisition of intangible assets	--	(1.4)	--	(1.4)	--	--	(1.4)
Investments in unconsolidated affiliates	(158.9)	(15.6)	167.4	(7.1)	(310.7)	310.7	(7.1)
Proceeds from asset sales and related transactions	--	0.3		0.3			0.3
Other investing activities	--	3.8	--	3.8	--	--	3.8
Cash used in investing activities	(236.7)	(483.3)	167.4	(552.6)	(310.7)	310.7	(552.6)
Financing activities:							
Borrowings under debt agreements	844.0	319.4	--	1,163.4	--	--	1,163.4
Repayments of debt	(631.6)	(284.3)	--	(915.9)	--	--	(915.9)
Cash distributions paid to partners	(287.6)	(61.3)	61.3	(287.6)	(279.7)	287.6	(279.7)
Cash distributions paid to noncontrolling interest	--	(114.8)	8.4	(106.4)	--	0.9	(105.5)
Net cash proceeds from issuance of common units	--	--	--	--	310.8	--	310.8
Cash contributions from members	310.7	152.2	(152.2)	310.7	--	(310.7)	--
Cash contributions from noncontrolling interest	--	148.7	(149.0)	(0.3)	--	(0.3)	(0.6)
Other financing activities	(0.7)	(0.2)	--	(0.9)	--	--	(0.9)
Cash provided by financing activities	234.8	159.7	(231.5)	163.0	31.1	(22.5)	171.6
Effect of exchange rate changes on cash	--	(2.0)	--	(2.0)	--	--	(2.0)
Net change in cash and cash equivalents	(0.3)	(9.4)	0.8	(8.9)	(0.1)	--	(9.0)
Cash and cash equivalents, January 1	1.0	69.7	(9.4)	61.3	0.2	0.2	61.7
Cash and cash equivalents, March 31	$ 0.7	$ 58.3	$ (8.6)	$ 50.4	$ 0.1	$ 0.2	$ 50.7

Note 18. Subsequent Events

Enterprise Products Partners Issues 13,800,000 Common Units

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 net cash proceeds of approximately $485.2 million (including a net capital contribution of approximately $9.7 million from EPGP to maintain its 2% general partner interest) to pay a portion of our announced acquisition of assets from M2 Midstream LLC ("Momentum") and for general partnership purposes.

Acquisition of Natural Gas Gathering Systems in Haynesville Shale Area from Momentum

On May 4, 2010, we purchased two natural gas gathering and treating systems from subsidiaries of Momentum for approximately $1.2 billion in cash. 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 Sands formations. We used a portion of the proceeds from our April 2010 underwritten equity offering, together with borrowings under EPO's Multi-Year Revolving Credit Facility, to pay for this acquisition. Given the recent nature of this transaction, we have not yet completed the related purchase price allocation. These systems will be integrated into our Onshore Natural Gas Pipelines & Services business segment and complement our existing assets.

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

For the three months ended March 31, 2010 and 2009.

The following information should be read in conjunction with our unaudited condensed consolidated financial statements and accompanying notes included in this report. The following information and such unaudited condensed consolidated financial statements should also be read in conjunction with the financial statements and related notes, together with our discussion and analysis of financial position and results of operations included in our annual report on Form 10-K for the year ended December 31, 2009 (our "2009 Form 10-K"). Our financial statements have been prepared in accordance with U.S. generally accepted accounting principles ("GAAP").

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 through which Enterprise Products Partners conducts substantially all of its business, 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"), 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, 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 Dan L. Dun can, 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: (1) Ms. Randa Duncan Williams, Mr. Duncan's oldest daughter, who is also an existing director on the board of EPE Holdings; (2) Dr. Ralph S. Cunningham, who is currently the President and Chief Executive Officer ("CEO") of EPE Holdings; and (3) Mr. Richard H. Bachmann, who is currently the Executive Vice President and Chief Legal Officer of EPGP and one of three managers of Dan Duncan LLC. Dr. Cunningham and Mr. Bachmann are also currently directors of EPGP, EPE Holdings and DEP GP.

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

References to "Energy Transfer Equity" mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries, which include Energy Transfer Partners, L.P. ("ETP").

Energy Transfer Equity is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "ETE." ETP is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "ETP." The general partner of Energy Transfer Equity is LE GP, LLC.

References to "EPCO" mean Enterprise Products Company (formerly EPCO, Inc.) and its privately held affiliates. Prior to Mr. Duncan's death on March 29, 2010, we, EPO, Duncan Energy Partners, DEP GP, EPGP, Enterprise GP Holdings and EPE Holdings were affiliates under the common control of Dan L. Duncan, the controlling shareholder of EPCO. 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 dated April 26, 2006 (the "EPCO Voting Trust Agreement"), among EPCO, Dan L. 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 Dan L. Duncan, as the initial sole voting trus tee. Immediately upon Mr. Duncan's death, voting and dispositive control of such majority of the outstanding voting capital stock of EPCO included under the EPCO Voting Trust Agreement was transferred pursuant to the EPCO Voting Trust Agreement to three voting trustees (the "EPCO Trustees"). The current EPCO Trustees are: (1) Ms. Williams, who serves as Chairman of EPCO; (2) Dr. Cunningham, who serves as a Vice Chairman of EPCO; and (3) 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 for the DD LLC Voting Trust, which controls 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 Dan L. Duncan. Dan Duncan LLC and EPCO also beneficially own approximately 18% and 57% , respectively, of the outstanding units representing limited partner interests of Enterprise GP Holdings.

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 expectation s 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 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 North American midstream energy company providing a wide range of services to producers and consumers of natural gas, natural gas liquids ("NGLs"), crude oil, refined products and certain 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. In addition, we are an industry leader in the development of pipeline and other midstream energy infrastructure in the continental United States and Gulf of Mexico. We are a publicly traded Delaware limited partnership formed in 1998, the common units of which are listed on the NYSE under the ticker symbol "EPD." We conduct substantially all of o ur business through EPO. We are owned 98% by our limited partners and 2% by our general partner, EPGP. EPGP is owned 100% by Enterprise GP Holdings.

In connection with the TEPPCO Merger, we revised our business segments. Our reorganized business segments reflect the manner in which these businesses are managed and reviewed by the CEO of our general partner. Under our new business segment structure, 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.

Basis of Financial Statement Presentation

Since Enterprise Products Partners, TEPPCO and TEPPCO GP were under common control of EPCO and its affiliates, 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. The inclusion of TEPPCO and TEPPCO GP in our consolidated financial statements was effective January 1, 2005 because an affiliate of EPCO under common control with Enterprise Products Partners originally acquired ownership interests in TEPPCO GP in February 2005.

Our consolidated financial statements 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 reflected as "Former owners of TEPPCO," a component of noncontrolling interest.

The financial statements of TEPPCO and TEPPCO GP were prepared from the separate accounting records maintained by TEPPCO and TEPPCO GP. All intercompany balances and transactions have been eliminated in consolidation.

There was no change in net income attributable to Enterprise Products Partners L.P. for periods prior to the merger since net income attributable to TEPPCO and TEPPCO GP was allocated to noncontrolling interests. Additionally, there was no change in our reported earnings per unit for such periods. See "Other Items" included within this Item 2 for information regarding total segment gross operating margin, which is a non-generally accepted accounting principle ("non-GAAP") financial measure of segment performance.

The following table reconciles total revenues and total gross operating margin for the three months ended March 31, 2009, as currently presented, with those we previously presented (dollars in millions):

Total revenues, as previously reported	$	3,423.1
Revenues from TEPPCO		1,457.5
Revenues from Jonah Gas Gathering Company ("Jonah") (1)		59.4
Eliminations (2)		(53.1)
Total revenues, as currently reported	$	4,886.9
Total segment gross operating margin, as previously reported	$	548.7
Gross operating margin from TEPPCO		151.2
Gross operating margin from Jonah		45.3
Eliminations (3)		(31.1)
Total segment gross operating margin, as currently reported	$	714.1

(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.
(2) Represents the elimination of revenues between Enterprise Products Partners, TEPPCO and Jonah.
(3) Represents the elimination of equity earnings from Jonah recorded by Enterprise Products Partners and TEPPCO prior to the merger.

Significant Recent Developments

The following information highlights specified 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.

Acquisition of Natural Gas Gathering Systems in Haynesville Shale Area from Momentum

On May 4, 2010, we purchased two natural gas gathering and treating systems, the State Line system and the Fairplay system from subsidiaries of M2 Midstream LLC ("Momentum") for approximately $1.2 billion in cash. 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 Sands formations. We used a portion of the proceeds from our April 2010 underwritten 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 includes 138 miles of natural gas pipelines with a capacity of approximately 400 MMcf/d and two treating facilities. The State Line system began operations in February 2009 and is currently gathering approximately 260 MMcf/d. A 50-mile expansion of this system is expected to be completed in June 2010 and will increase its capacity to 700 MMcf/d. The State Line system is supported by long-term acreage dedications and volumetric commitments from producers. The State Line system will interconnect with the 42-inch Haynesville Extension of our Acadian Gas System. The Haynesville Extension is currently under construction and expected to be completed in the third quart er of 2011. Once connected to the Haynesville Extension, the State Line system can be further expanded to 1.2 Bcf/d for a nominal cost.

The Fairplay system is located in Rusk, Panola, Gregg and Nacogdoches counties, Texas. The system includes 249 miles of natural gas pipelines (including approximately 62 miles leased from third parties) with a capacity of approximately 285 MMcf/d, and is currently gathering approximately 180 MMcf/d. This system is expected to be connected to the Enterprise Texas Pipeline system by the first quarter of 2011. The Fairplay system is also supported by long-term acreage dedications and volumetric commitments from producers.

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

(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 March 31,	
	2010	**2009**
NGL Pipelines & Services, net:		
NGL transportation volumes (MBPD)	2,240	2,121
NGL fractionation volumes (MBPD)	473	441
Equity NGL production (MBPD)	122	114
Fee-based natural gas processing (MMcf/d)	2,679	3,104
Onshore Natural Gas Pipelines & Services, net:		
Natural gas transportation volumes (BBtus/d)	10,706	10,339
Onshore Crude Oil Pipelines & Services, net:		
Crude oil transportation volumes (MBPD)	672	645
Offshore Pipelines & Services, net:		
Natural gas transportation volumes (BBtus/d)	1,406	1,542
Crude oil transportation volumes (MBPD)	354	126
Platform natural gas processing (MMcf/d)	632	777
Platform crude oil processing (MBPD)	18	3
Petrochemical Services, net:		
Butane isomerization volumes (MBPD)	73	90
Propylene fractionation volumes (MBPD)	80	68
Octane additive production volumes (MBPD)	11	5
Transportation volumes, primarily refined products and petrochemicals (MBPD)	804	841
Total, net:		
NGL, crude oil, refined products and petrochemical transportation volumes (MBPD)	4,070	3,733
Natural gas transportation volumes (BBtus/d)	12,112	11,881
Equivalent transportation volumes (MBPD) (1)	7,257	6,860

(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 March 31,	
	2010	**2009**
Revenues	$ 8,544.5	$ 4,886.9
Operating costs and expenses	7,971.9	4,376.6
General and administrative costs	37.6	34.9
Equity in income of unconsolidated affiliates	16.0	7.4
Operating income	551.0	482.8
Interest expense	148.6	152.5
Provision for income taxes	8.7	16.0
Net income	393.8	315.5
Net income attributable to noncontrolling interest	16.0	90.2
Net income attributable to Enterprise Products Partners L.P.	377.8	225.3

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

	For the Three Months Ended March 31,	
	2010	2009
Gross operating margin by segment:		
NGL Pipelines & Services	$ 437.3	$ 350.9
Onshore Natural Gas Pipelines & Services	130.3	161.9
Onshore Crude Oil Pipelines & Services	26.7	50.5
Offshore Pipeline & Services	81.1	61.3
Petrochemical & Refined Products Services	120.0	89.5
Total segment gross operating margin	$ 795.4	$ 714.1

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

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

	For the Three Months Ended March 31,	
	2010	2009
NGL Pipelines & Services:		
Sales of NGLs	$ 3,664.1	$ 2,252.2
Sales of other petroleum and related products	0.5	0.5
Midstream services	181.7	167.7
Total	3,846.3	2,420.4
Onshore Natural Gas Pipelines & Services:		
Sales of natural gas	975.2	556.6
Midstream services	186.3	176.9
Total	1,161.5	733.5
Onshore Crude Oil Pipelines & Services:		
Sales of crude oil	2,367.3	1,245.8
Midstream services	19.3	24.1
Total	2,386.6	1,269.9
Offshore Pipelines & Services:		
Sales of natural gas	0.4	0.3
Sales of crude oil	2.1	0.2
Midstream services	86.1	68.0
Total	88.6	68.5
Petrochemical & Refined Products Services:		
Sales of other petroleum and related products	932.6	261.5
Midstream services	128.9	133.1
Total	1,061.5	394.6
Total consolidated revenues	$ 8,544.5	$ 4,886.9

Comparison of Three Months Ended March 31, 2010 with Three Months Ended March 31, 2009

Revenues for the first quarter of 2010 were $8.54 billion compared to $4.89 billion for the first quarter of 2009. The $3.66 billion quarter-to-quarter increase in consolidated revenues is primarily due to higher energy commodity prices and sales volumes during the first quarter of 2010 compared to the first quarter of 2009. These factors accounted for a $3.63 billion quarter-to-quarter increase in consolidated revenues associated with our NGL, natural gas, crude oil, petrochemical and refined products marketing activities. Revenues increased $8.7 million quarter-to-quarter as a result of aggregate property damage and business interruption insurance proceeds we received during the first quarter of 2010 associated with our

Offshore Pipelines & Services business segment. Collectively, the remainder of our consolidated revenues increased $23.8 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 $7.97 billion for the first quarter of 2010 compared to $4.38 billion for the first quarter of 2009, a $3.59 billion quarter-to-quarter increase. The cost of sales of our marketing activities increased $3.25 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 $264.3 million quarter-to-quarter primarily due to higher plant thermal reduction ("PTR") costs attributable to an increase in natural gas prices. Collectively, the remainder of our consolidated operating costs and expenses increased $85.1 million quarter-to-quarter reflecting an increase in expenses for fuel, maintenance, employee compensation and depreciation. ;General and administrative costs increased $2.7 million quarter-to-quarter.

Changes in our revenues and costs and expenses quarter-to-quarter are primarily due to changes in energy commodity prices. The weighted-average indicative market price for NGLs was $1.23 per gallon during the first quarter of 2010 versus $0.66 per gallon during the first quarter of 2009 – an 86% increase quarter-to-quarter. Our determination of the weighted-average indicative market price for NGLs is based on U.S. Gulf Coast prices for such products at Mont Belvieu, Texas, which is the primary industry hub for domestic NGL production. The market price of natural gas (as measured at Henry Hub in Louisiana) averaged $5.30 per MMBtu during the first quarter of 2010 versus $4.91 per MMBtu during the first quarter of 2009. The market price of crude oil (as measured on the NYMEX) averaged $7 8.72 per barrel during the first quarter of 2010 compared to $43.31 per barrel during the first quarter of 2009 – an 82% increase quarter-to-quarter. See "—Selected Price and Volumetric Data" included above in this Item 2 for additional historical energy commodity pricing information.

Equity in income of our unconsolidated affiliates was $16.0 million for the first quarter of 2010 compared to $7.4 million for the first quarter of 2009, an $8.6 million quarter-to-quarter increase. Equity in income from our investments in Cameron Highway Oil Pipeline Company and Poseidon Oil Pipeline Company, L.L.C. collectively increased $6.2 million quarter-to-quarter primarily due to higher crude oil transportation volumes. Collectively, equity in income of our other investments increased $2.4 million quarter-to-quarter largely due to improved results from our investments in south Louisiana.

Operating income for the first quarter of 2010 was $551.0 million compared to $482.8 million for the first quarter of 2009. Collectively, the changes in revenues, costs and expenses and equity in income of unconsolidated affiliates described above contributed to the $68.2 million quarter-to-quarter increase in operating income.

Interest expense decreased to $148.6 million for the first quarter of 2010 from $152.5 million for the first quarter of 2009. The $3.9 million quarter-to-quarter decrease in interest expense is primarily due to lower average debt balances, which were partially offset by a $6.9 million quarter-to-quarter decrease in capitalized interest. Average debt principal outstanding decreased to $11.17 billion during the first quarter of 2010 from $11.71 billion during the first quarter of 2009 reflecting lower average balances outstanding under revolving credit facilities.

Provision for income taxes decreased $7.3 million quarter-to-quarter primarily due to a one-time charge of $6.6 million associated with taxable gains arising from Dixie Pipeline Company's sale of certain assets during the first quarter of 2009.

As a result of items noted in the previous paragraphs, our consolidated net income increased $78.3 million quarter-to-quarter to $393.8 million for the first quarter of 2010 compared to $315.5 million for the first quarter of 2009. Net income attributable to noncontrolling interests was $16.0 million for the first quarter of 2010 compared to $90.2 million for the first quarter of 2009. Noncontrolling interest for the first quarter of 2009 reflects $78.3 million of net income attributable to the former owners of TEPPCO. Net income attributable to Enterprise Products Partners increased $152.5 million quarter-to-quarter to $377.8 million for the first quarter of 2010 compared to $225.3 million for the first 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 $437.3 million for the first quarter of 2010 compared to $350.9 million for the first quarter of 2009, an $86.4 million quarter-to-quarter increase.

Gross operating margin from our natural gas processing and related NGL marketing business was $259.7 million for the first quarter of 2010 compared to $194.6 million for the first quarter of 2009, a $65.1 million quarter-to-quarter increase. Equity NGL production increased to 122 MBPD during the first quarter of 2010 from 114 MBPD during the first quarter of 2009. Our Rocky Mountain natural gas processing plants contributed $25.8 million of the quarter-to-quarter increase in gross operating margin primarily due to the Phase II expansion of our Meeker facility that we completed during March 2009. Our Rocky Mountain natural gas processing plants produced 71 MBPD of equity NGLs during the first quarter of 2010 compared to 53 MBPD during the first quarter of 2009. Our NGL marketing activities co ntributed $19.9 million of the quarter-to-quarter increase in gross operating margin primarily due to increased sales volumes and recognition of earnings associated with forward sales transactions that were settled during the first quarter of 2010. Collectively, gross operating margin from the remainder of these business activities increased $19.4 million quarter-to-quarter primarily due to higher natural gas processing margins in Louisiana and Texas.

Gross operating margin from our NGL pipelines and related storage business was $150.1 million for the first quarter of 2010 compared to $126.4 million for the first quarter of 2009, a $23.7 million quarter-to-quarter increase. Total NGL transportation volumes increased to 2,240 MBPD during the first quarter of 2010 from 2,121 MBPD during the first quarter of 2009. Gross operating margin from our pipelines in South Louisiana, Dixie pipeline and Mid-America and Seminole pipelines increased $11.2 million quarter-to-quarter primarily due to an increase in transportation volumes and higher average fees. Gross operating margin from our Mont Belvieu storage facility increased $5.5 million quarter-to-quarter primarily due to increased storage volumes and fees. Collectively, gross operating margin fr om the remainder of these business activities increased $7.0 million quarter-to-quarter primarily due to increased utilization of our NGL import/export terminal on the Houston Ship Channel 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 $27.5 million for the first quarter of 2010 compared to $29.9 million for the first quarter of 2009. The $2.4 million quarter-to-quarter decrease was primarily due to operating gains recorded during the first quarter of 2009, which more than offset the effects of an increase in fractionation volumes from all of our NGL fractionators during the first quarter of 2010. Fractionation volumes were 473 MBPD during the first quarter of 2010 compared to 441 MBPD during the first quarter of 2009.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was $130.3 million for the first quarter of 2010 compared to $161.9 million for the first quarter of 2009, a $31.6 million quarter-to-quarter decrease. Our onshore natural gas transportation volumes were 10,706 BBtus/d during the first quarter of 2010 compared to 10,339 BBtus/d during the first quarter of 2009.

Gross operating margin from our onshore natural gas pipeline and related natural gas marketing business was $116.0 million for the first quarter of 2010 compared to $148.9 million for the first quarter of 2009, a $32.9 million quarter-to-quarter decrease. Gross operating margin from our natural gas marketing activities decreased $42.9 million quarter-to-quarter 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 greater during the first quarter of 2009 relative to the first quarter of 2010. Higher basis differentials during the first quarter of 2009 resulted in a quarter-to-quarter decrease in natural gas sales margins a ssociated with our marketing activities and lower pipeline throughput volumes during the first quarter of 2010. Also, construction delays associated with our Trinity River Lateral have resulted in a loss of approximately $3.0 million per month during 2010 for transportation capacity charges on a downstream pipeline incurred by our natural gas marketing business. These charges will be offset by the benefits of natural gas volumes originating on the Trinity River Lateral when it commences operation, which is currently expected in July 2010.

Gross operating margin from our Texas Intrastate System increased $2.1 million quarter-to-quarter primarily due to $15.7 million of firm capacity reservation fees generated by the Sherman Extension pipeline during the first quarter of 2010 and an increase in condensate sales revenues due to higher commodity prices. These benefits were partially offset by the effects of lower throughput volumes on other parts of the Texas Intrastate System and higher operating expenses during the first quarter of 2010 compared to the first quarter of 2009. The Sherman Extension pipeline began earning firm capacity reservation fees during August 2009. Collectively, gross operating margin from the remainder of our natural gas pipeline assets increased $7.9 million quarter-to-quarter primarily due to improved results from our San Juan Gathering System as a result of increased revenues earned from natural gas gathering contracts where fees are indexed to regional natural gas prices and higher condensate sales revenues.

Gross operating margin from our natural gas storage business was $14.3 million for the first quarter of 2010 compared to $13.0 million for the first quarter of 2009. The $1.3 million quarter-to-quarter increase in gross operating margin is primarily due to higher firm storage reservation fees at our Wilson facility.

Onshore Crude Oil Pipelines & Services. Gross operating margin from this business segment was $26.7 million for the first quarter of 2010 compared to $50.5 million for the first quarter of 2009. Total onshore crude oil transportation volumes were 672 MBPD during the first quarter of 2010 compared to 645 MBPD during the first quarter of 2009. The $23.8 million quarter-to-quarter decrease in gross operating margin is primarily due to our crude oil marketing activities, which experienced lower sales margins and volumes during the first quarter of 2010 relative to the first quarter of 2009. Lower crude oil sales margins reflect a quarter-to-quarter decrease in basis differentials between the price of (i) Wes t Texas Intermediate crude oil versus West Texas Sour crude oil and (ii) Oklahoma Sour crude oil versus Domestic Sweet crude oil. Also, earnings associated with the settlement of forward crude oil sales transactions were greater during the first quarter of 2009 compared to the first quarter of 2010.

Offshore Pipelines & Services. Gross operating margin from this business segment was $81.1 million for the first quarter of 2010 compared to $61.3 million for the first quarter of 2009, a $19.8 million quarter-to-quarter increase. Results for the first quarter of 2010 include $8.7 million of proceeds from insurance claims. The following paragraphs provide a discussion of segment results excluding insurance proceeds.

Gross operating margin from our offshore crude oil pipeline business was $25.3 million for the first quarter of 2010 compared to $5.1 million for the first quarter of 2009, a $20.2 million quarter-to-quarter increase. Our Shenzi crude oil pipeline, which commenced operations in April 2009, contributed gross operating margin of $9.1 million during the first quarter of 2010. Collectively, gross operating margin from the remainder of our crude oil pipelines increased $11.1 million quarter-to-quarter due to increased transportation volumes. Certain of these pipelines were either in limited service or out of service during the first quarter of 2009 due to volume disruptions caused by the effects of Hurricanes Gustav and Ike. Total offshore crude oil transportation volumes were 354 MBPD during the first quarter of 2010 versus 126 MBPD during the first quarter of 2009.

Gross operating margin from our offshore natural gas pipeline business was $12.2 million for the first quarter of 2010 compared to $17.7 million for the first quarter of 2009. Offshore natural gas transportation volumes were 1,406 BBtus/d during the first quarter of 2010 versus 1,542 BBtus/d during the first quarter of 2009. Collectively, gross operating margin from our offshore natural gas pipelines decreased $5.5 million quarter-to-quarter primarily due to lower transportation volumes on our Independence Trail pipeline.

Gross operating margin from our offshore platform services business was $34.9 million for the first quarter of 2010 compared to $38.5 million for the first quarter of 2009. Our net platform natural gas processing volumes were 632 MMcf/d during the first quarter of 2010 compared to 777 MMcf/d during the first quarter of 2009. The $3.6 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 primarily as a result of production declines, downtime for construction of a deck extension and other maintenance work and recompletion of the Mondo well that was finished in March 2010. Producers currently expect to recomplete an additional well during 2010 and add wells during 2010 and 2011.

Petrochemical & Refined Products Services. Gross operating margin from this business segment increased $30.5 million to $120.0 million for the first quarter of 2010 from $89.5 million for the first quarter of 2009.

Gross operating margin from propylene fractionation and related activities was $43.1 million for the first quarter of 2010 compared to $23.0 million for the first quarter of 2009. The $20.1 million quarter-to-quarter increase in gross operating margin is primarily due to higher propylene fractionation volumes and sales margins during the first quarter of 2010 relative to the first quarter of 2009. Propylene fractionation volumes increased to 80 MBPD during the first quarter of 2010 from 68 MBPD during the first quarter of 2009.

Gross operating margin from octane enhancement was $4.1 million for the first quarter of 2010 compared to a loss of $8.1 million for the first quarter of 2009. The $12.2 million quarter-to-quarter increase in gross operating margin is primarily due to higher margins from sales of methyl tertiary butyl ether (“MTBE”) into export markets and revenues from by-product sales. Octane enhancement production volumes were 11 MBPD during the first quarter of 2010 compared to 5 MBPD during the first quarter of 2009.

Gross operating margin from butane isomerization was $14.8 million for the first quarter of 2010 compared to $14.9 million for the first quarter of 2009. The $0.1 million quarter-to-quarter decrease in gross operating margin is primarily due to lower isomerization volumes, the effect of which was partially offset by higher commodity prices resulting in increased revenues from the sale of by-products. Butane isomerization volumes decreased to 73 MBPD during the first quarter of 2010 from 90 MBPD during the first quarter of 2009.

Gross operating margin from refined products pipelines and related activities was $48.9 million for the first quarter of 2010 compared to $45.5 million for the first quarter of 2009. The $3.4 million quarter-to-quarter increase in gross operating margin is primarily due to lower operating expenses, higher average transportation fees and an increase in refined products marketing activities, which more than offset the effect of lower transportation volumes. Pipeline transportation volumes for the refined products business were 682 MBPD during the first quarter of 2010 compared to 724 MBPD during the first quarter of 2009.

Gross operating margin from marine transportation and other services was $9.1 million for the first quarter of 2010 compared to $14.2 million for the first quarter of 2009. The $5.1 million quarter-to-quarter decrease in gross operating margin is primarily due to higher repair and maintenance expenses during the first quarter of 2010. A greater percentage of our fleet of marine vessels is scheduled to undergo periodic inspections and repairs during 2010 as compared to 2009. Higher maintenance expenses were partially offset by an increase in gross operating margin as a result of our acquisition of 19 push boats and 28 barges in June 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 par tners primarily with operating cash flows. Our debt service requirements are expected to be funded by operating cash flows and/or refinancing arrangements.

At March 31, 2010, we had $134.9 million of unrestricted cash on hand and approximately $1.86 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 $11.05 billion in principal outstanding under consolidated debt agreements at March 31, 2010. In total, our consolidated liquidity at March 31, 2010 was approximately $1.99 billion.

Registration Statements

We may issue equity or debt securities to assist us in meeting our liquidity and capital spending requirements. Duncan Energy Partners may do likewise in meeting its liquidity and capital spending requirements. We have a universal shelf registration statement on file with the SEC that would allow us to issue an unlimited amount of debt and equity securities for general partnership purposes.

The following table presents information regarding equity offerings made under our universal shelf registration statement since January 1, 2010 through the date of this filing. Dollar amounts presented in the tables are in millions, except offering price amounts.

Underwritten Equity Offering	Number of Common Units Issued	Offering Price	Net Cash Proceeds
January 2010 underwritten offering (1)	10,925,000	$ 32.42	$ 343.3
April 2010 underwritten offering (2)	13,800,000	$ 35.55	475.5
Total	24,725,000		$ 818.8

(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 for our acquisition of assets from Momentum and for general partnership purposes.

At March 31, 2010, Duncan Energy Partners could issue approximately $856.4 million of additional equity or debt securities under its 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 three months ended March 31, 2010, we issued 2,795,549 common units in connection with our DRIP, which generated proceeds of $83.8 million from plan participants. Affiliates of EPCO reinvested $69.5 million in connection with the DRIP during the three months ended March 31, 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 three months ended March 31, 2010, we issued 39,035 common units to employees under this plan, which generated proceeds of $1.2 million.

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

Letter of Credit Facilities

At March 31, 2010, EPO had outstanding a $58.3 million letter of credit related to its Petal GO Zone Bonds. This letter of credit facility does not reduce the amount available for borrowing under EPO's credit facilities. In April 2010, EPO entered into a $50.0 million letter of credit facility related to its commodity derivative instruments.

Credit Ratings

At May 10, 2010, the investment-grade credit ratings of EPO's senior unsecured debt securities remain unchanged from March 31, 2010 at Baa3 by Moody's Investor Services; BBB- by Fitch Ratings; and BBB- by Standard and Poor's. On April 30, 2010, Standard and Poor's affirmed EPO's corporate credit rating, revised its outlook to "positive" from "stable" and revised its business risk assessment to "strong" from "satisfactory." Such ratings reflect only the view of a rating agency and should not be interpreted as a recommendation to buy, sell or hold any security. Any rating can be revised upward or downward or withdrawn at any time by a rating agency if it determines that the circumstances warrant such a change and should be eval uated independently of any other rating.

Based on the characteristics of the $1.53 billion of fixed/floating unsecured junior subordinated notes, the rating agencies assigned partial equity treatment to the notes. Moody's Investor Services and Standard and Poor's each assigned 50% equity treatment and Fitch Ratings assigned 75% equity treatment. In April 2010, Moody's published a request for comment with respect to changes Moody's is proposing regarding its evaluation of the credit attributes of hybrid securities such as our junior subordinated notes. Moody's proposed changes include reducing the equity credit that Moody's assigns to securities such as our junior subordinated notes from 50% to 25%. Irrespective of whether Moody's ultimately assigns 50% or 25% equity credit to our junior subordinated notes, we d o not believe this will affect our Baa3 senior unsecured debt rating.

A downgrade of our credit ratings could result in our being required to post financial collateral up to the amount of our guaranty of indebtedness of our Centennial joint venture, which was $58.9 million at March 31, 2010. Furthermore, from time to time we enter into contracts in connection with our commodity and interest rate hedging activities that may require the posting of financial collateral if our credit 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 Three Months Ended March 31, 2010	For the Three Months Ended March 31, 2009
Net cash flows provided by operating activities	$ 686.9	$ 372.0
Cash used in investing activities	370.5	552.6
Cash provided by (used in) financing activities	(236.6)	171.6

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

Comparison of Three Months Ended March 31, 2010 with Three Months Ended March 31, 2009

Operating Activities. The $314.9 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 and cash payments for interest) increased $363.9 million quarter-to-quarter. The increase in operating cash flow is generally due to increased profitability and the timing of related cash receipts and disbursements.

§ Cash payments for interest increased $56.8 million quarter-to-quarter primarily due to an increase in fixed-rate debt obligations quarter-to-quarter.

Investing Activities. The $182.1 million decrease in cash used for investing activities was primarily due to the following:

§ Capital spending for property, plant and equipment, net of contributions in aid of construction costs, decreased $163.3 million quarter-to-quarter. For additional information related to our capital spending program, see "Liquidity and Capital Resources – Capital Spending" included within this Item 2.

§ Proceeds from asset sales and related transactions increased $21.4 million quarter-to-quarter.

Financing Activities. Cash used in financing activities was $236.6 million for the three months ended March 31, 2010 compared to cash provided by financing activities of $171.6 million for the three months ended March 31, 2009. The $408.2 million change in financing activities was primarily due to the following:

§ Net repayments under our consolidated debt agreements of $249.5 million for the three months ended March 31, 2010 compared to net borrowings under our consolidated debt agreements of $247.5 million for the three months ended March 31, 2009. During the three months ended March 31, 2010, EPO temporarily repaid the outstanding balance of its Multi-Year Revolving Credit Facility and its Pascagoula Mississippi Business Finance Corporation ("MBFC") Loan matured and was repaid. For information regarding our consolidated debt obligations see Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

§ Cash distributions paid to our partners increased $127.6 million quarter-to-quarter due to increases in our common units outstanding and quarterly distribution rates.

§ Distributions paid to noncontrolling interests decreased $88.1 million quarter-to-quarter primarily due to the cessation of TEPPCO's cash distributions following the TEPPCO Merger.

§ Net cash proceeds from the issuance of our common units increased $126.9 million quarter-to-quarter primarily due to more common units issued at a higher price in our underwritten equity offering in January 2010 compared to our 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, Midcontinent, Northeast and U.S. Gulf Coast regions, including the Barnett Shale, Haynesville Shale, Eagle Ford Shale, Marcellus Shale and deepwater Gulf of Mexico 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 forecast that 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 Three Months Ended March 31,	
	2010	2009
Capital spending for property, plant and equipment, net of contributions in aid of construction costs	$ 344.2	$ 507.5
Capital spending for business combinations	2.2	--
Capital spending for intangible assets	--	1.4
Capital spending for investments in unconsolidated affiliates	7.7	7.1
Total capital spending	$ 354.1	$ 516.0

Based on information currently available, we estimate our consolidated capital spending for the remainder of 2010 will be approximately $2.66 billion, which includes estimated expenditures of $2.43 billion for growth capital projects and acquisitions and $230.0 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 March 31, 2010, we had approximately $639.3 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 March 31, 2010	For the Three Months Ended March 31, 2009
Expensed	$ 9.4	$ 7.4
Capitalized	2.7	3.5
Total	$ 12.1	$ 10.9

We expect the costs of our pipeline integrity program, irrespective of whether such costs are capitalized or expensed, to approximate $87.3 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 na tural gas imbalances. These estimates are based on our current knowledge and understanding and may change as a result of actions we may take in the future. Changes in these estimates will occur as a result of the passage of time and the occurrence of future events. Subsequent changes in these estimates may have a significant impact on our financial position, results of operations and cash flows.

Other Items

Duncan Energy Partners

For information regarding our relationship with Duncan Energy Partners, see Note 12 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

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 are customary and sufficient for the nature and extent of our operations. For additional information regarding insurance matters, see Note 15 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Contractual Obligations

With the exception of routine fluctuations in the balance of our consolidated revolving credit facilities and the repayment of our Pascagoula MBFC Loan, there have been no significant changes in our contractual obligations since those reported in our 2009 Form 10-K.

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.

Related Party Transactions

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

Non-GAAP Reconciliations

The following table presents a reconciliation of our 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 March 31, 2010	2009
Total segment gross operating margin	$ 795.4	$ 714.1
Adjustments to reconcile total segment gross operating margin to operating income:		
Depreciation, amortization and accretion in operating costs and expenses	(212.4)	(196.4)
Non-cash impairment charges	(1.5)	--
Operating lease expenses paid by EPCO	(0.2)	(0.2)
Gain from asset sales and related transactions in operating costs and expenses	7.3	0.2
General and administrative costs	(37.6)	(34.9)
Operating income	551.0	482.8
Other expense, net	(148.5)	(151.3)
Income before provision for income taxes	$ 402.5	$ 331.5

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 additi onal 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) Scenario	**Resulting Classification**	**Swap Fair Value at March 31, 2010**	**Swap Fair Value at April 20, 2010**
FV assuming no change in underlying interest rates	*Asset*	$ 48.6	$ 44.3
FV assuming 10% increase in underlying interest rates	*Asset*	43.5	39.4
FV assuming 10% decrease in underlying interest rates	*Asset*	53.7	49.2

Duncan Energy Partners Scenario	**Resulting Classification**	**Swap Fair Value at March 31, 2010**	**Swap Fair Value at April 20, 2010**
FV assuming no change in underlying interest rates	*Liability*	$ (3.8)	$ (3.8)
FV assuming 10% increase in underlying interest rates	*Liability*	(3.8)	(3.8)
FV assuming 10% decrease in underlying interest rates	*Liability*	(3.8)	(3.8)

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 March 31, 2010**	**Swap Fair Value at April 20, 2010**
FV assuming no change in underlying interest rates	*Asset*	$ 15.5	$ 12.7
FV assuming 10% increase in underlying interest rates	*Asset*	35.0	32.1
FV assuming 10% decrease in underlying interest rates	*Liability*	(5.9)	(8.6)

On April 27 and in May 2010, we entered into four additional forward starting swaps each with a notional amount of $50.0 million. The period hedged by these four forward starting swaps is February 2012 through February 2022.

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-based derivative instruments such as forward contracts, futures, swaps and options to mitigate such risks.

We assess the risk of our commodity financial 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 March 31, 2010**	**Portfolio Fair Value at April 20, 2010**
FV assuming no change in underlying commodity prices	*Liability*	$ (4.4)	$ (4.4)
FV assuming 10% increase in underlying commodity prices	*Liability*	(9.0)	(10.5)
FV assuming 10% decrease in underlying commodity prices	*Asset*	0.1	1.6

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 March 31, 2010	Portfolio Fair Value at April 20, 2010
FV assuming no change in underlying commodity prices	*Liability*	$ (40.6)	$ (41.8)
FV assuming 10% increase in underlying commodity prices	*Liability*	(91.4)	(96.4)
FV assuming 10% decrease in underlying commodity prices	*Asset*	10.2	12.9

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 March 31, 2010	Portfolio Fair Value at April 20, 2010
FV assuming no change in underlying commodity prices	*Asset*	$ --	$ 0.9
FV assuming 10% increase in underlying commodity prices	*Liability*	(1.0)	(3.9)
FV assuming 10% decrease in underlying commodity prices	*Asset*	1.1	5.8

Our predominant hedging strategy is to hedge an amount of gross margin associated with the gas processing activities. We achieve this by using physical and financial instruments to lock in the prices of NGL sales and natural gas purchases used for PTR. This program consists of:

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

§ the purchase of commodity derivative instruments with a notional amount determined by the amount of natural gas expected to be consumed as PTR in the production of such equity NGL production.

At March 31, 2010, this program had hedged future estimated gross margins (before plant operating expenses) of $322.3 million on 10.5 MMBbls of forecasted NGL forward sales transactions and equivalent PTR volumes extending through December 2010. At April 26, 2010, this program had hedged future estimated gross margins (before plant operating expenses) of $431.4 million on 14.4 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 the exchange rate. At March 31, 2010, we did not have any foreign currency derivative instruments outstanding.

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

Item 1A. *Risk Factors*.

Security holders and potential investors in our securities should carefully consider the risk factors set forth in our 2009 Form 10-K and below in addition to other information in such report and in this quarterly report. We have identified these risk factors as important factors that could cause our actual results to differ materially from those contained in any written or oral forward-looking statements made by us or on our behalf.

The death of Dan L. Duncan represents a 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 the effect of the loss of Mr. Duncan at this time and cannot provide any assurances that his loss will not have any effect on our business, results of operations or cash flows.

Federal and certain 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. A decline caused by these initiatives in the volume of natural gas, NGLs and crude oil delivered to our facilities could adversely affect our financial position, results of operations and cash flows.

The U.S. Congress is considering legislation to amend the federal Safe Drinking Water Act to require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Hydraulic fracturing is an important and commonly used process in the completion of unconventional oil and natural gas wells in shale and tight sand formations. Sponsors of these bills, which are currently pending in the Energy and Commerce Committee and the Environmental and Public Works Committee of the House of Representatives and Senate, respectively, have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. The proposed legislation would require the reporting and public disclosure of chemicals used in the fracturing process, which could mak e it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, these bills, if adopted, could establish additional Federal regulations that could lead to operational delays or increased operating costs in the production of crude oil and natural gas 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 crude oil or natural gas production, our profitability could be materially impacted by a decline in the volume of natural gas, NGLs and crude oil transported, gathered or processed at our facilities.

An extended drilling moratorium for new drilling 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 30, 2010, officials in the Obama Administration indicated that Federal agencies would not authorize new offshore drilling in U.S. waters pending review of the oil spill of the Transocean drilling rig on a BP plc property on April 20, 2010. This announcement states that no additional drilling will be authorized until the administration completes its review of the cause of the blast and determination of whether the blast was unique and preventable. If this moratorium continues for an extended period, or if the review results in Federal legislation, policy, restrictions or regulations that cause delays or deter new drilling in the U.S. Gulf of Mexico or other areas in which our assets are located, future natural gas and crude oil volumes to our pipelines and facilities may decline or be lower than prev iously anticipated. A decline in, or failure to achieve anticipated, volumes due to these reasons may have a material adverse effect on our financial position, results of operations and cash flows.

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

As of March 31, 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 announced program during the three months ended March 31, 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 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	--	--

(1) Of the 34,528 restricted units that vested in February 2010 and converted to common units, 7,480 of these 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	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).
4.26	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).
4.27	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).
4.28	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).
4.29	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).
4.30	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).
4.31	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).
4.32	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).
4.33	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).
4.34	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).
4.35	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).
4.36	Form of Junior Subordinated Note, including Guarantee (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006).
4.37	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).
4.38	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).
4.39	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).
4.40	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).
4.41	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).
4.42	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).

4.43	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).
4.44	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).
4.45	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).
4.46	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).
4.47	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).
4.48	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).
4.49	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).
4.50	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).
4.51	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).
4.52	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).
4.53	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).
4.54	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).
4.55	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).
4.56	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).
4.57	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).

4.58	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).
4.59	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).
4.60	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).
4.61	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).
4.62	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).
4.63	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).
4.64	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).
4.65	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).
4.66	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).
4.67	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).
4.68	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).

4.69	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).
4.70	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***	Enterprise Products 1998 Long-Term Incentive Plan (Amended and Restated as of February 23, 2010) (incorporated by reference to Exhibit 10.1 to Form 8-K filed February 26, 2010).
10.2***	Amendment to Form of Option Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued before February 23, 2010 (incorporated by reference to Exhibit 10.2 to Form 8-K filed February 26, 2010).
10.3***	Form of Option Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Form 8-K filed February 26, 2010).
10.4***	Amendment to Form of Restricted Unit Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan for awards issued before February 23, 2010 (incorporated by reference to Exhibit 10.4 to Form 8-K filed February 26, 2010).
10.5***	Form of Employee Restricted Unit Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.5 to Form 8-K filed February 26, 2010).
10.6***	Form of Non-Employee Director Restricted Unit Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.6 to Form 8-K filed February 26, 2010).
10.7***	Enterprise Products Company 2005 EPE Long-Term Incentive Plan (amended and restated as of February 23, 2010) (incorporated by reference to Exhibit 10.1 to Form 8-K filed by Enterprise GP Holdings L.P. on February 26, 2010).
10.8***	Form of Option Grant Award under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to Form 8-K filed by Enterprise GP Holdings L.P. on February 26, 2010).
10.9***	Form of Employee Restricted Unit Grant Award under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Form 8-K filed by Enterprise GP Holdings L.P. on February 26, 2010).
10.10***	Form of Non-Employee Director Restricted Unit Grant Award under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.4 to Form 8-K filed by Enterprise GP Holdings L.P. on February 26, 2010).
10.11***	Form of Phantom Unit Grant Award under the Enterprise Products Company 2005 EPE Long-Term Incentive Plan (incorporated by reference to Exhibit 10.5 to Form 8-K filed by Enterprise GP Holdings L.P. on February 26, 2010).
10.12***	Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan (February 23, 2010) (incorporated by reference to Exhibit 10.7 to Form 8-K filed February 26, 2010).
10.13***	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 (incorporated by reference to Exhibit 10.8 to Form 8-K filed February 26, 2010).
10.14***	Form of Option Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan (incorporated by reference to Exhibit 10.9 to Form 8-K filed February 26, 2010).
10.15***	Form of Employee Restricted Unit Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan (incorporated by reference to Exhibit 10.10 to Form 8-K filed February 26, 2010).
10.16***	Form of Non-Employee Director Restricted Unit Grant Award under the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan (incorporated by reference to Exhibit 10.11 to Form 8-K filed February 26, 2010).

10.17***	2010 Duncan Energy Partners L.P. Long-Term Incentive Plan (Amended and Restated February 23, 2010) (incorporated by reference to Exhibit 10.1 to Form 8-K filed by Duncan Energy Partners L.P. on February 26, 2010).
10.18***	Form of Option Grant Award under the 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to Form 8-K filed by Duncan Energy Partners L.P. on February 26, 2010).
10.19***	Form of Employee Restricted Unit Grant Award under the 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Form 8-K filed by Duncan Energy Partners L.P. on February 26, 2010).
10.20***	Form of Non-Employee Director Restricted Unit Grant Award under the 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.4 to Form 8-K filed by Duncan Energy Partners L.P. on February 26, 2010).
31.1#	Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise Products Partners L.P. for the March 31, 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 March 31, 2010 Quarterly Report on Form 10-Q.
32.1#	Section 1350 certification of Michael A. Creel for the March 31, 2010 Quarterly Report on Form 10-Q.
32.2#	Section 1350 certification of W. Randall Fowler for the March 31, 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 May 10, 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

EXHIBIT 31.1

CERTIFICATIONS

I, Michael A. Creel, certify that:

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

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

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

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

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

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

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

Date: May 10, 2010

/s/ Michael A. Creel

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

EXHIBIT 31.2

CERTIFICATIONS

I, W. Randall Fowler, certify that:

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

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

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

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

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

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

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

Date: May 10, 2010

/s/ W. Randall Fowler

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

EXHIBIT 32.1

SARBANES-OXLEY SECTION 906 CERTIFICATION

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

In connection with this quarterly report of Enterprise Products Partners L.P. (the “Registrant”) on Form 10-Q for the three months ended March 31, 2010 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Michael A. Creel, Chief Executive Officer of Enterprise Products GP, LLC, the General Partner of the Registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

/s/ Michael A. Creel

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

Date: May 10, 2010

EXHIBIT 32.2

SARBANES-OXLEY SECTION 906 CERTIFICATION

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

In connection with this quarterly report of Enterprise Products Partners L.P. (the "Registrant") on Form 10-Q for the three months ended March 31, 2010 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, W. Randall Fowler, Chief Financial Officer of Enterprise Products GP, LLC, the General Partner of the Registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

/s/ W. Randall Fowler

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

Date: May 10, 2010