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

FORM 8-K/A

CURRENT REPORT

Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): November 22, 2010

ENTERPRISE PRODUCTS PARTNERS L.P.

(Exact name of registrant as specified in its charter)

Delaware	**1-14323**	**76-0568219**
(State or Other Jurisdiction of Incorporation or Organization)	(Commission File Number)	(I.R.S. Employer Identification No.)

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

Registrant’s Telephone Number, including Area Code: **(713) 381-6500**

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

This Form 8-K/A is being filed in connection with the Form 8-K filed by Enterprise Products Partners L.P. on November 23, 2010 to file the unaudited financial statements of Enterprise GP Holdings L.P. ("Holdings") previously omitted therein.

Item 9.01 Financial Statements and Exhibits.

(a) *Financial Statements of Business Acquired*. The unaudited financial statements of Holdings for the nine months ended September 30, 2010 are hereby filed in accordance with Item 9.01(a) of Form 8-K as Exhibit 99.6 and incorporated herein by reference.

(d) *Exhibits.*

Exhibit No.	Description
99.6#	Unaudited Condensed Consolidated Financial Statements of Enterprise GP Holdings L.P. as of and for the Nine Months Ended September 30, 2010.
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.

Filed herewith

SIGNATURES

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

ENTERPRISE PRODUCTS PARTNERS L.P.

By: ENTERPRISE PRODUCTS HOLDINGS LLC
(formerly named EPE Holdings, LLC),
its General Partner

Date:	November 23, 2010	By:	/s/ Michael J. Knesek
		Name:	Michael J. Knesek
		Title:	Senior Vice President, Controller and Principal Accounting Officer of the General Partner

Exhibit Index

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Exhibit 99.6

ENTERPRISE GP HOLDINGS L.P.
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PART I. FINANCIAL INFORMATION.

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

ENTERPRISE GP HOLDINGS L.P.
UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEETS
(Dollars in millions)

ASSETS	September 30, 2010	December 31, 2009
Current assets:		
Cash and cash equivalents	$ 42.9	$ 55.3
Restricted cash	32.5	63.6
Accounts and notes receivable – trade, net of allowance for doubtful accounts of $18.1 at September 30, 2010 and $16.8 at December 31, 2009	3,036.6	3,099.0
Accounts receivable – related parties	31.0	38.4
Inventories	1,210.0	711.9
Prepaid and other current assets	292.9	281.4
Total current assets	4,645.9	4,249.6
Property, plant and equipment, net	18,810.0	17,689.2
Investments in unconsolidated affiliates	2,331.2	2,416.2
Intangible assets, net of accumulated amortization of $894.7 at September 30, 2010 and $795.0 at December 31, 2009	1,860.3	1,064.8
Goodwill	2,052.7	2,018.3
Other assets	246.5	248.2
Total assets	$ 29,946.6	$ 27,686.3
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable – trade	$ 519.4	$ 410.6
Accounts payable – related parties	99.0	70.8
Accrued product payables	3,338.6	3,393.0
Accrued interest	178.2	231.7
Other current liabilities	494.1	447.8
Total current liabilities	4,629.3	4,553.9
Long-term debt (see Note 10)	13,790.1	12,427.9
Deferred tax liabilities	75.0	71.7
Other long-term liabilities	277.3	159.7
Commitments and contingencies		
Equity: (see Note 11)		
Enterprise GP Holdings L.P. partners' equity:		
Limited Partners:		
Units (139,195,064 Units outstanding at September 30, 2010 and 139,191,640 Units outstanding at December 31, 2009)	1,909.6	1,972.4
General partner	**	**
Accumulated other comprehensive loss	(46.0)	(33.3)
Total Enterprise GP Holdings L.P. partners' equity	1,863.6	1,939.1
Noncontrolling interest	9,311.3	8,534.0
Total equity	11,174.9	10,473.1
Total liabilities and equity	$ 29,946.6	$ 27,686.3

See Notes to Unaudited Condensed Consolidated Financial Statements.
** Amount is negligible.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	**2009***	**2010**	**2009***
Revenues:				
Third parties	$ 7,934.1	$ 6,679.0	$ 23,673.6	$ 16,688.4
Related parties	133.7	110.4	482.1	422.2
Total revenues (see Note 12)	8,067.8	6,789.4	24,155.7	17,110.6
Costs and expenses:				
Operating costs and expenses:				
Third parties	7,117.1	6,128.2	21,441.1	15,046.4
Related parties	343.0	267.6	965.1	750.5
Total operating costs and expenses	7,460.1	6,395.8	22,406.2	15,796.9
General and administrative costs:				
Third parties	28.8	28.3	61.5	63.4
Related parties	41.3	26.0	89.4	78.6
Total general and administrative costs	70.1	54.3	150.9	142.0
Total costs and expenses (see Note 12)	7,530.2	6,450.1	22,557.1	15,938.9
Equity in income of unconsolidated affiliates	5.6	14.1	43.2	57.7
Operating income	543.2	353.4	1,641.8	1,229.4
Other income (expense):				
Interest expense	(192.0)	(170.9)	(529.1)	(508.2)
Interest income	0.9	0.4	1.6	2.0
Other, net	0.4	(0.3)	0.2	0.2
Total other expense, net	(190.7)	(170.8)	(527.3)	(506.0)
Income before provision for income taxes	352.5	182.6	1,114.5	723.4
Provision for income taxes	(4.9)	(7.7)	(20.1)	(26.8)
Net income	347.6	174.9	1,094.4	696.6
Net income attributable to noncontrolling interests	(310.6)	(149.6)	(933.4)	(569.3)
Net income attributable to Enterprise GP Holdings L.P.	$ 37.0	$ 25.3	$ 161.0	$ 127.3
Allocation of net income attributable to Enterprise GP Holdings L.P.:				
Limited partners	$ 37.0	$ 25.3	$ 161.0	$ 127.3
General partner	$ **	$ **	$ **	$ **
Basic and diluted earnings per Unit (see Note 14)	$ 0.27	$ 0.18	$ 1.16	$ 0.93

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

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009*	2010	2009*
Net income	$ 347.6	$ 174.9	$ 1,094.4	$ 696.6
Other comprehensive income (loss):				
Cash flow hedges:				
Commodity derivative instrument losses during period	(64.1)	(8.3)	(31.0)	(146.9)
Reclassification adjustment for (gains) losses included in net income related to commodity derivative instruments	(25.6)	77.8	(10.6)	176.3
Interest rate derivative instrument gains (losses) during period	(81.6)	(11.3)	(168.4)	3.0
Reclassification adjustment for losses included in net income related to interest rate derivative instruments	8.1	6.7	21.4	20.3
Foreign currency derivative gains (losses) during period	0.1	0.2	(0.1)	(10.3)
Reclassification adjustment for gains included in net income related to foreign currency derivative instruments	--	--	(0.3)	--
Total cash flow hedges	(163.1)	65.1	(189.0)	42.4
Foreign currency translation adjustment	0.5	1.1	0.3	1.7
Change in funded status of pension and postretirement plans, net of tax	--	--	(0.9)	--
Proportionate share of other comprehensive income (loss) of unconsolidated affiliate	11.9	(1.7)	11.5	0.1
Total other comprehensive income (loss)	(150.7)	64.5	(178.1)	44.2
Comprehensive income	196.9	239.4	916.3	740.8
Comprehensive income attributable to noncontrolling interests	(167.2)	(211.7)	(768.0)	(602.4)
Comprehensive income attributable to Enterprise GP Holdings L.P.	$ 29.7	$ 27.7	$ 148.3	$ 138.4

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

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

	For the Nine Months Ended September 30, 2010	For the Nine Months Ended September 30, 2009*
Operating activities:		
Net income	$ 1,094.4	$ 696.6
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	709.1	622.2
Non-cash asset impairment charges	1.5	26.3
Equity in income of unconsolidated affiliates	(43.2)	(57.7)
Distributions received from unconsolidated affiliates	146.0	117.0
Operating lease expenses paid by EPCO	0.5	0.5
Gains from asset sales and related transactions	(45.4)	(0.5)
Loss on forfeiture of investment in Texas Offshore Port System	--	68.4
Deferred income tax expense	3.7	2.5
Changes in fair market value of derivative instruments	(10.8)	9.8
Effect of pension settlement recognition	(0.2)	(0.1)
Net effect of changes in operating accounts (see Note 17)	(411.8)	(574.9)
Net cash flows provided by operating activities	1,443.8	910.1
Investing activities:		
Capital expenditures	(1,405.1)	(1,100.4)
Contributions in aid of construction costs	13.9	12.8
Decrease in restricted cash	37.9	100.8
Cash used for business combinations (see Note 8)	(1,233.0)	(74.5)
Investments in unconsolidated affiliates	(6.3)	(14.7)
Proceeds from asset sales and related transactions	89.6	2.9
Other investing activities	1.5	0.1
Cash used in investing activities	(2,501.5)	(1,073.0)
Financing activities:		
Borrowings under debt agreements	4,170.3	5,037.7
Repayments of debt	(2,816.6)	(4,666.5)
Debt issuance costs	(14.7)	(5.2)
Cash distributions paid to partners	(227.6)	(195.0)
Cash distributions paid to noncontrolling interests	(1,099.0)	(980.0)
Cash contributions from noncontrolling interests	1,034.4	991.9
Acquisition of treasury units by subsidiary	(3.1)	(1.8)
Other financing activities	1.3	--
Cash provided by financing activities	1,045.0	181.1
Effect of exchange rate changes on cash	0.3	(0.4)
Net change in cash and cash equivalents	(12.7)	18.2
Cash and cash equivalents, January 1	55.3	56.8
Cash and cash equivalents, September 30	$ 42.9	$ 74.6

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

ENTERPRISE GP HOLDINGS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED EQUITY
(See Note 11 for Unit History and Detail of Accumulated Other Comprehensive Loss)
(Dollars in millions)

	Enterprise GP Holdings L.P.				
	Limited Partners	General Partner	Accumulated Other Comprehensive Loss	Noncontrolling Interest	Total
Balance, December 31, 2009	$ 1,972.4	$ **	$ (33.3)	$ 8,534.0	$ 10,473.1
Net income	161.0	**	--	933.4	1,094.4
Operating lease expenses paid by EPCO	--	--	--	0.5	0.5
Cash distributions paid to partners	(227.6)	**	--	--	(227.6)
Cash distributions paid to noncontrolling interests	--	--	--	(1,099.0)	(1,099.0)
Cash contributions from noncontrolling interests	--	--	--	1,034.4	1,034.4
Amortization of equity awards	3.8	--	--	45.9	49.7
Acquisition of treasury units by subsidiary	--	--	--	(3.1)	(3.1)
Issuance of common units by subsidiary to EPCO in exchange for equity interests in trucking business	--	--	--	30.6	30.6
Foreign currency translation adjustment	--	--	--	0.3	0.3
Change in fair value of cash flow hedges	--	--	(24.2)	(164.8)	(189.0)
Proportionate share of other comprehensive income of unconsolidated affiliates	--	--	11.5	--	11.5
Other	--	--	--	(0.9)	(0.9)
Balance, September 30, 2010	$ 1,909.6	$ **	$ (46.0)	$ 9,311.3	$ 11,174.9

	Enterprise GP Holdings L.P.				
	Limited Partners	General Partner	Accumulated Other Comprehensive Loss	Noncontrolling Interest	Total
Balance, December 31, 2008*	$ 2,031.2	$ **	$ (53.2)	$ 7,781.4	$ 9,759.4
Net income	127.3	**	--	569.3	696.6
Operating lease expenses paid by EPCO	--	--	--	0.5	0.5
Cash distributions paid to partners	(195.0)	**	--	--	(195.0)
Cash distributions paid to noncontrolling interests	--	--	--	(980.0)	(980.0)
Deconsolidation of Texas Offshore Port System (see Note 1)	--	--	--	(33.4)	(33.4)
Cash contributions from noncontrolling interests	--	--	--	991.9	991.9
Amortization of equity awards	1.8	--	--	16.7	18.5
Acquisition of treasury units by subsidiary	--	--	--	(1.8)	(1.8)
Foreign currency translation adjustment	--	--	0.1	1.6	1.7
Change in fair value of cash flow hedges	--	--	10.9	31.5	42.4
Proportionate share of other comprehensive loss of unconsolidated affiliates	--	--	0.1	--	0.1
Other	--	--	--	(0.2)	(0.2)
Balance, September 30, 2009*	$ 1,965.3	$ **	$ (42.1)	$ 8,377.5	$ 10,300.7

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

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,” “Holdings” or the “Partnership” are intended to mean the business and operations of Enterprise GP Holdings L.P. and its consolidated subsidiaries.

References to the “Parent Company” mean Enterprise GP Holdings L.P., individually as the parent company, and not on a consolidated basis. On September 3, 2010, the Parent Company and Enterprise Products Partners (as defined below) entered into an Agreement and Plan of Merger (the “Holdings Merger Agreement”) that would, if approved by the Parent Company’s unitholders, result in the merger of the Parent Company with a wholly owned subsidiary of Enterprise Products Partners through a unit-for-unit exchange (the “Holdings Merger”). See Note 1 for additional information regarding the proposed Holdings Merger.

References to “EPE Holdings” mean EPE Holdings, LLC, which is the general partner of the Parent Company and a wholly owned subsidiary of Dan Duncan LLC. The membership interests of Dan Duncan LLC are owned of record by a voting trust formed on April 26, 2006, pursuant to the Dan Duncan LLC Voting Trust Agreement dated April 26, 2006 (the “DD LLC Voting Trust Agreement”), among Dan Duncan LLC and Dan L. Duncan (as the record owner of all of the membership interests of Dan Duncan LLC immediately prior to the entering into of the DD LLC Voting Trust Agreement and as the initial sole voting trustee).

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

The DD LLC Voting Trust Agreement requires that there always be two “Independent Voting Trustees” serving. If Mr. Bachmann or Dr. Cunningham fail to qualify or cease to serve, then the substitute or successor Independent Voting Trustee(s) will be appointed by the then-serving Independent Voting Trustee, provided that if no Independent Voting Trustee is then serving or if a vacancy in a trusteeship of an Independent Voting Trustee is not filled within 90 days of the vacancy’s occurrence, the CEO of the general partner of Enterprise Products Partners (as defined below), currently Michael A. Creel, will appoint the successor Independent Voting Trustee(s).

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

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

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

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

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

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

Immediately upon Mr. Duncan's death, voting and dispositive control of such majority of the outstanding voting capital stock of EPCO was transferred pursuant to the EPCO Voting Trust Agreement to three voting trustees (the "EPCO Trustees"). The current EPCO Trustees are: (i) Ms. Williams, who serves as Chairman of EPCO; (ii) Dr. Cunningham, who serves as a Vice Chairman of EPCO; and (iii) Mr. Bachmann, who serves as the President, CEO and Chief Legal Officer of EPCO. Ms. Williams, Dr. Cunningham and Mr. Bachmann are also currently directors of EPCO. The current EPCO Trustees are the same as the current DD LLC Trustees, which control Dan Duncan LLC. The current EPCO Trustees are also the same persons as the individuals appointed on April 27, 2010 as the independent co-execut ors of the estate of Mr. Duncan.

References to "Enterprise Products Partners" mean Enterprise Products Partners L.P., a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "EPD," and its consolidated subsidiaries. Enterprise Products Partners conducts substantially all of its business through Enterprise Products Operating LLC ("EPO") and its consolidated subsidiaries. Enterprise Products Partners completed the mergers of TEPPCO Partners, L.P. ("TEPPCO") and Texas Eastern Products Pipeline Company, LLC ("TEPPCO GP") with its subsidiaries on October 26, 2009. We refer to such related mergers both individually and in the aggregate as the "TEPPCO Merger." R eferences to "EPGP" refer to Enterprise Products GP, LLC, which is the general partner of Enterprise Products Partners. EPGP is owned by the Parent Company and is responsible for managing the business and operations of Enterprise Products Partners.

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 NYSE under the ticker symbol "DEP." References to "DEP GP" mean DEP Holdings, LLC, which is the general partner of Duncan Energy Partners and wholly owned by EPO.

References to "Energy Transfer Equity" mean the business and operations of Energy Transfer Equity, L.P. and its consolidated subsidiaries, which include Energy Transfer Partners, L.P. ("ETP") and, effective May 26, 2010, Regency Energy Partners LP ("RGNC"). Energy Transfer Equity is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "ETE." ETP is a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol "ETP." RGNC is a publicly traded Delaware limited partnership, the common units of which are traded on the NASDAQ stock market under the ticker symbol "RGNC." The general partner of Energy Transfer Equity is LE GP, LLC ("LE GP"). The Parent Company owns noncontrolling interests in both Energy Transfer Equity and LE GP that it accounts for using the equity method of accounting. We do not control Energy Transfer Equity or LE GP.

References to the "Employee Partnerships" mean EPE Unit L.P., EPE Unit II, L.P., EPE Unit III, L.P., Enterprise Unit L.P. and EPCO Unit L.P. ("EPCO Unit"), collectively, all of which were privately held affiliates of EPCO. The Employee Partnerships were liquidated in August 2010. See Note 3 for additional information.

Additionally, Enterprise Products Partners, Duncan Energy Partners and Energy Transfer Equity electronically file certain documents with the SEC, including annual reports on Form 10-K and quarterly reports on Form 10-Q. The SEC maintains an Internet website at www.sec.gov that contains periodic reports and other information regarding these registrants.

Note 1. Partnership Organization and Basis of Presentation

Parent Company

The Parent Company is a publicly traded Delaware limited partnership, the limited partnership interests (the "Units") of which are listed on the NYSE under the ticker symbol "EPE." Our business consists of the ownership of general and limited partner interests of publicly traded partnerships engaged in the midstream energy industry and related businesses. Our goal is to increase cash distributions to unitholders.

The Parent Company is owned 99.99% by its limited partners and 0.01% by its general partner, EPE Holdings. EPE Holdings is a wholly owned subsidiary of Dan Duncan LLC, the membership interests of which are currently owned of record collectively by the DD LLC Trustees. The Parent Company has no operations apart from its investing activities and indirectly overseeing the management of the entities controlled by it. At September 30, 2010, the Parent Company had investments in Enterprise Products Partners, Energy Transfer Equity and their respective general partners.

Interim Reporting

Our results of operations for the three and nine months ended September 30, 2010 are not necessarily indicative of results expected for the full year. In our opinion, the accompanying Unaudited Condensed Consolidated Financial Statements include all adjustments consisting of normal recurring accruals necessary for fair presentation. Although we believe the disclosures in these financial statements are adequate to make the information presented not misleading, certain information and footnote disclosures normally included in annual financial statements prepared in accordance with U.S. generally accepted accounting principles ("GAAP") have been condensed or omitted pursuant to the rules and regulations of the U.S. Securities and Exchange Commission ("SEC"). These Unaudited Condens ed Consolidated Financial Statements and the Notes thereto should be read in conjunction with the Audited Consolidated Financial Statements and Notes thereto included in our annual report on Form 10-K for the year ended December 31, 2009 (the "2009 Form 10-K").

Basis of Presentation

General Purpose Consolidated and Parent Company-Only Information. In accordance with rules and regulations of the SEC and various other accounting standard-setting organizations, our general purpose financial statements reflect the consolidation of the financial information of businesses that we control through the ownership of general partner interests (i.e., Enterprise Products Partners). Our general purpose consolidated financial statements present those investments in which we do not have a controlling interest as unconsolidated affiliates (i.e., Energy Transfer Equity and LE GP). As presented in our consolidated financial statements, noncontrolling interest reflects third-party and related party ownership of our c onsolidated subsidiaries, which include the third-party and related party unitholders of Enterprise Products Partners and Duncan Energy Partners other than the Parent Company.

In order for the unitholders of Enterprise GP Holdings L.P. and others to more fully understand the Parent Company's business and financial statements on a standalone basis, Note 18 includes information devoted exclusively to the Parent Company apart from that of our consolidated Partnership. A key difference between the non-consolidated Parent Company financial information and those of our consolidated Partnership is that the Parent Company views each of its investments (i.e., Enterprise Products Partners and Energy Transfer Equity) as unconsolidated affiliates and records its share of the net income of each as equity income in the Parent Company income information. In accordance with GAAP, we eliminate the equity income related to Enterprise Products Partners in the preparation of our consolidated financi al statements.

Presentation of Investments. The Parent Company owns common units of Enterprise Products Partners and 100% of the membership interests of EPGP, which is entitled to 2% of the cash distributions paid by Enterprise Products Partners as well as the associated incentive distribution rights ("IDRs") of Enterprise Products Partners. At September 30, 2010 and December 31, 2009, the Parent Company owned 21,563,177 and 21,167,783 common units, respectively, of Enterprise Products Partners.

The Parent Company owns 38,976,090 common units of Energy Transfer Equity and approximately 40.6% of the membership interests of LE GP. Energy Transfer Equity owns limited partner interests and the general partner interest of ETP. In addition, Energy Transfer Equity owns certain limited partner interests in and 100% of the general partner of RGNC. We account for our investments in Energy Transfer Equity and LE GP using the equity method of accounting.

Proposed Merger of the Parent Company with Enterprise Products Partners

On September 3, 2010, Enterprise Products Partners and the Parent Company entered into an Agreement and Plan of Merger that would, if approved by the Parent Company's unitholders, result in the merger of the Parent Company with a wholly owned subsidiary of Enterprise Products Partners through a unit-for-unit exchange. Consequently, the Parent Company would become a wholly owned subsidiary of Enterprise Products Partners. Under the terms of the Holdings Merger Agreement, the Parent Company's unitholders will be entitled to receive 1.5 of Enterprise Products Partners' common units in exchange for each limited partner unit of the Parent Company they own at closing. As a result, Enterprise Products Partners expects to issue, in the aggregate, 208,813,477 of its common units to the Parent Company's unitholders. The proposed transaction would also result in the cancellation of 21,563,177 of Enterprise Products Partners' common units currently held by the Parent Company as well as the general partner's 2% economic interest and its incentive distribution rights in Enterprise Products Partners. Affiliates of EPCO will continue to own Enterprise Products Partners' general partner following the merger.

The proposed merger must receive the affirmative vote of the Parent Company's unitholders owning at least a majority of the Parent Company's outstanding units as of the record date. Subject to the terms and conditions of a support agreement, privately held affiliates of EPCO (the "Holdings supporting unitholders") have agreed to vote their 105,739,220 units of the Parent Company, representing approximately 76% of the Parent Company's outstanding units, in favor of the proposed merger. The support agreement will automatically terminate on December 31, 2010 or upon the earlier termination of the Holdings Merger Agreement. The Holdings supporting unitholders may terminate their obligations under the support agreement in certain circumstances, including specified changes in U.S. federal income tax law if such changes occur prior to the closing of the merger.

In connection with the proposed merger, a privately held affiliate of EPCO has agreed to temporarily waive the regular quarterly cash distributions it would otherwise receive from Enterprise Products Partners on an initial amount of 30,610,000 of its common units (the "Designated Units") for a five-year period after the merger closing date. The number of Designated Units to which the temporary distribution waiver would apply is as follows for distributions to be paid during the following periods, if any: 30,610,000 during 2011; 26,130,000 during 2012; 23,700,000 during 2013; 22,560,000 during 2014; and 17,690,000 during 2015.

The Holdings Merger Agreement contains customary representations and warranties and covenants by each of the parties. Completion of the proposed merger is conditioned upon, among other things: (i) the absence of certain legal impediments prohibiting the transactions, (ii) applicable regulatory approvals and (iii) the conditions precedent contained in the Holdings Merger Agreement having been satisfied. The Holdings Merger Agreement contains provisions granting Enterprise Products Partners and the Parent Company the right to terminate the agreement for certain reasons, including, among others, if the proposed merger does not occur on or before December 31, 2010.

TEPPCO Merger

On October 26, 2009, the related mergers of wholly owned subsidiaries of Enterprise Products Partners with TEPPCO and TEPPCO GP were completed. Under terms of the merger agreements, TEPPCO and TEPPCO GP became wholly owned subsidiaries of Enterprise Products Partners, and each of TEPPCO's unitholders, except for a privately held affiliate of EPCO, received 1.24 common units of Enterprise Products Partners for each TEPPCO unit they owned. In total, Enterprise Products Partners issued an aggregate of 126,932,318 common units and 4,520,431 Class B units (described below) as consideration in the TEPPCO Merger for both TEPPCO units and the TEPPCO GP membership interests. On October 27, 2009, the 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 Class B units of Enterprise Products Partners in lieu of common units. The Class B units are not entitled to receive regular quarterly cash distributions for the first sixteen quarters following the closing date of the merger. The Class B units automatically convert into the same number of common units on the date immediately following the payment date for the sixteenth regular quarterly distribution following the closing date of the merger. The Class B units are entitled to vote together with the common units as a single class on partnership matters and, except for the payment of distributions, have the same rights and privileges as Enterprise Products Partners' common units .

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

Due to common control considerations, the TEPPCO Merger was accounted for at historical costs as a reorganization of entities under common control in a manner similar to a pooling of interests. As a result, our consolidated financial statements and business segments were recast to reflect the TEPPCO Merger. Our recast consolidated financial statements for periods prior to the TEPPCO Merger reflect the combined financial information of Enterprise Products Partners, TEPPCO and TEPPCO GP on a 100% basis. Third-party and related party ownership interests in TEPPCO and TEPPCO GP are presented as "Former owners of TEPPCO," which is a component of noncontrolling interest. Investors should use our recast consolidated financial statements when making comparisons between our current and pr ior period financial information.

Deconsolidation of Texas Offshore Port System

In August 2008, Enterprise Products Partners, including TEPPCO, together with Oiltanking Holding Americas, Inc. ("Oiltanking") formed the Texas Offshore Port System partnership ("TOPS"). In April 2009, Enterprise Products Partners and TEPPCO dissociated from TOPS. As a result, our operating costs and expenses and net income for the second quarter of 2009 include a non-cash charge of $68.4 million. This loss represents the forfeiture of our cumulative investment, including that of TEPPCO, in TOPS through the date of dissociation. The impact on net income attributable to Enterprise GP Holdings L.P. was approximately $8.7 million, as nearly all of this loss was absorbed by noncontrolling interests in consolidation (i.e., by the former owners of TEPPCO).

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

In September 2009, we entered into a settlement agreement with certain affiliates of Oiltanking that resolved all disputes between the parties related to the business and affairs of the TOPS project. We recognized approximately $66.9 million of expense during the third quarter of 2009 in connection with the payment of this cash settlement.

Note 2. General Accounting Matters

Estimates

Preparing our financial statements in conformity with GAAP requires management to make estimates and assumptions that affect amounts presented in the financial statements (e.g., assets, liabilities, revenue and expenses) and disclosures regarding contingent assets and liabilities. Our actual results could differ from these estimates. On an ongoing basis, management reviews its estimates based on currently available information. Any future changes in facts and circumstances may require updated estimates, which, in turn, could have a significant impact on our financial statements.

Fair Value Information

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

The following table presents the estimated fair values of our financial instruments at the dates indicated:

Financial Instruments	September 30, 2010 Carrying Value	September 30, 2010 Fair Value	December 31, 2009 Carrying Value	December 31, 2009 Fair Value
Financial assets:				
Cash and cash equivalents and restricted cash	$ 75.4	$ 75.4	$ 118.9	$ 118.9
Accounts receivable	3,067.6	3,067.6	3,137.4	3,137.4
Financial liabilities:				
Accounts payable and accrued expenses	4,135.2	4,135.2	4,106.1	4,106.1
Other current liabilities (excluding derivative instruments)	339.0	339.0	341.7	341.7
Fixed-rate debt (principal amount)	12,032.7	13,205.5	10,586.7	11,056.2
Variable-rate debt	1,707.6	1,707.6	1,791.8	1,791.8

Recent Accounting Developments

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

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

Restricted Cash

Restricted cash represents amounts held in connection with our commodity derivative instruments portfolio and related physical natural gas and NGL purchases. Additional cash may be restricted to maintain this portfolio as commodity prices fluctuate or deposit requirements change. At September 30, 2010 and December 31, 2009, our restricted cash amounts were $32.5 million and $63.6 million, respectively. Our restricted cash balances have decreased since December 31, 2009 due to a reduction in margin requirements related to our commodity hedging activities. See Note 4 for information regarding our derivative instruments and hedging activities.

Note 3. Equity-based Awards

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
Restricted unit awards (1)	$ 9.6	$ 4.4	$ 23.3	$ 11.0
Unit option awards (1)	1.2	0.7	3.1	1.5
Unit appreciation rights (2)	0.2	0.1	0.5	--
Phantom units (2)	--	0.1	0.1	0.2
Profits interests awards (1) (3)	19.6	2.1	23.4	5.8
Total compensation expense	$ 30.6	$ 7.4	$ 50.4	$ 18.5

(1) Accounted for as equity-classified awards.
(2) Accounted for as liability-classified awards.
(3) The increase between periods is due to the liquidation of the Employee Partnerships in August 2010 (see below).

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

At September 30, 2010, EPCO's long-term incentive plans applicable to our operations were the Enterprise Products 1998 Long-Term Incentive Plan, the Enterprise Products Company 2005 EPE Long-Term Incentive Plan, the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan and the 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan. In addition, there were unvested awards outstanding under an inactive plan, the Enterprise Products 2006 TPP Long-Term Incentive Plan ("2006 Plan"). EPCO's equity-based awards also included profits interests in the Employee Partnerships until their liquidation in August 2010.

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

Restricted Unit Awards

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

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

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

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Enterprise Products Partners L.P. restricted unit awards:		
Restricted units at December 31, 2009	2,720,882	$ 27.70
Granted (2,3)	1,353,425	$ 32.36
Vested (3)	(339,628)	$ 25.26
Forfeited	(103,558)	$ 29.54
Restricted units at September 30, 2010	3,631,121	$ 29.61
Duncan Energy Partners L.P. restricted unit awards:		
Restricted units at December 31, 2009	--	
Granted (3,4)	6,348	$ 25.26
Vested (3)	(6,348)	$ 25.26
Restricted units at September 30, 2010	--	
Parent Company restricted unit awards:		
Restricted units at December 31, 2009	--	
Granted (3,5)	3,424	$ 41.47
Vested (3)	(3,424)	$ 41.47
Restricted units at September 30, 2010	--	

(1) Determined by dividing the aggregate grant date fair value of awards before an allowance for forfeitures by the number of awards issued.
(2) Aggregate grant date fair value of restricted unit awards denominated in Enterprise Products Partners' common units was $43.8 million based on a grant date market price of Enterprise Products Partners' common units ranging from $32.00 to $38.36 per unit. Estimated forfeiture rates ranging between 4.6% and 17% were applied to these awards.
(3) Includes awards granted to the independent directors of the boards of directors of EPE Holdings, EPGP and DEP GP as part of their annual compensation for 2010. A total of 6,960, 6,348 and 3,424 restricted unit awards were issued in 2010 to the independent directors of EPGP, DEP GP and EPE Holdings, respectively, that immediately vested upon issuance.
(4) Aggregate grant date fair value of restricted unit awards denominated in Duncan Energy Partners' common units was $0.2 million based on a grant date market price of Duncan Energy Partners' common units of $25.26 per unit.
(5) Aggregate grant date fair value of restricted unit awards denominated in the Parent Company's Units issued was $0.1 million based on a grant date market price of the Parent Company's Units ranging from $39.99 to $51.66 per unit.

In the aggregate, unrecognized compensation cost of restricted unit awards was $53.2 million at September 30, 2010, of which our allocated share of the cost is currently estimated to be $48.8 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.1 years.

Unit Option Awards

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

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

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

	Number of Units	Weighted-Average Strike Price (dollars/unit)	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (1)
Unit options at December 31, 2009	3,825,920	$ 26.52		
Granted (2)	785,000	$ 32.26		
Exercised	(812,500)	$ 25.01		
Unit options at September 30, 2010	3,798,420	$ 28.03	3.9	$ 0.7
Options exercisable at September 30, 2010	45,000	$ 24.30	4.4	$ 0.7

(1) Aggregate intrinsic value reflects fully vested unit options at the date indicated.

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

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
Total intrinsic value of option awards exercised during period	$ 7.5	$ 0.3	$ 9.7	$ 0.6
Cash received from EPCO in connection with the exercise of unit option awards	5.0	0.3	6.6	0.5
Unit option-related reimbursements to EPCO	7.5	0.2	9.7	0.5

In the aggregate, unrecognized compensation cost of unit option awards was $8.5 million at September 30, 2010, of which our allocated share of the cost is currently estimated to be $7.6 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.5 years.

Unit Appreciation Rights

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

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

	September 30, 2010	December 31, 2009
Accrued liability for UARs	$ 0.8	$ 0.3

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

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

Phantom Unit Awards

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

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

Phantom unit awards at December 31, 2009	14,927
Granted	6,200
Vested (1)	(4,327)
Phantom unit awards at September 30, 2010	16,800

(1) Primarily consists of 3,472 phantom unit awards outstanding under the TEPPCO 1999 Phantom Unit Retention Plan at December 31, 2009, which vested in January 2010. The plan was subsequently terminated.

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

	September 30, 2010	December 31, 2009
Accrued liability for phantom unit awards	$ 0.3	$ 0.2

Profits Interests Awards

As long-term incentive arrangements, EPCO granted its key employees who perform services on behalf of us, EPCO and other affiliated companies, "profits interests" in the Employee Partnerships. These partnerships were liquidated in August 2010. Prior to liquidation, the profits interests awards entitled each holder to participate in the expected long-term appreciation in value of the equity securities owned by each Employee Partnership. Each Employee Partnership owned either Enterprise Products Partners' common units or the Parent Company's units or a combination of both. During the three months ended September 30, 2010, we recognized approximately $27 million of expense in connection with the liquidation of the Employee Partnerships, of which approximately $22 million was attributed to noncontrolling interest. Of this expense amount, approximately $19 million was non-cash.

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

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

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

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

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

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

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

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

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

Interest Rate Derivative Instruments

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

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

Hedged Transaction	Number and Type of Derivative(s) Employed	Notional Amount	Period of Hedge	Rate Swap	Accounting Treatment
Parent Company:					
Variable-interest rate borrowings	2 floating-to-fixed swaps	$250.0	9/07 to 8/11	0.5% to 4.8%	Cash flow hedge
Variable-interest rate borrowings	6 floating-to-fixed swaps	$600.0	5/10 to 7/14	0.5% to 2.0%	Cash flow hedge
Enterprise Products Partners:					
Senior Notes C	1 fixed-to-floating swap	$100.0	1/04 to 2/13	6.4% to 2.6%	Fair value hedge
Senior Notes G	3 fixed-to-floating swaps	$300.0	10/04 to 10/14	5.6% to 1.4%	Fair value hedge
Senior Notes P	7 fixed-to-floating swaps	$400.0	6/09 to 8/12	4.6% to 2.7%	Fair value hedge

In September 2010, Duncan Energy Partners' three floating-to-fixed swaps with a notional amount of $175.0 million expired.

Interest rate swaps exchange the stated interest rate paid on a notional amount of debt for a fixed or floating interest rate stipulated in the derivative instrument. Our interest rate swaps associated with existing debt obligations resulted in an increase in interest expense of $1.3 million and $4.1 million for the three months ended September 30, 2010 and 2009, respectively. For the nine months ended September 30, 2010 and 2009, such swaps resulted in a decrease in interest expense of $0.9 million and an increase in interest expense of $13.4 million, respectively.

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

Hedged Transaction	Number and Type of Derivatives Employed	Notional Amount	Expected Termination Date	Average Rate Locked	Accounting Treatment
Future debt offering	3 forward starting swaps	$250.0	2/11	3.7%	Cash flow hedge
Future debt offering	10 forward starting swaps	$500.0	2/12	4.5%	Cash flow hedge
Future debt offering	3 forward starting swaps	$150.0	8/12	4.0%	Cash flow hedge
Future debt offering	16 forward starting swaps	$1,000.0	3/13	3.7%	Cash flow hedge

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

Commodity Derivative Instruments

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

	Volume (1)		**Accounting**
Derivative Purpose	**Current**	**Long-Term** (2)	**Treatment**
<u>Derivatives designated as hedging instruments:</u>			
Enterprise Products Partners:			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction ("PTR") (3)	19.0 Bcf	n/a	Cash flow hedge
Forecasted sales of NGLs (4)	5.1 MMBbls	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchases of NGLs	0.8 MMBbls	n/a	Cash flow hedge
Forecasted sales of NGLs	0.1 MMBbls	n/a	Cash flow hedge
Forecasted sales of octane enhancement products	1.4 MMBbls	n/a	Cash flow hedge
Natural gas marketing:			
Natural gas storage inventory management activities	3.8 Bcf	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products	10.4 MMBbls	0.7 MMBbls	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products	13.5 MMBbls	1.0 MMBbls	Cash flow hedge
Crude oil marketing:			
Forecasted purchases of crude oil	3.0 MMBbls	n/a	Cash flow hedge
Forecasted sales of crude oil	4.3 MMBbls	n/a	Cash flow hedge
Duncan Energy Partners:			
Forecasted sales of natural gas	1.0 Bcf	n/a	Cash flow hedge
<u>Derivatives not designated as hedging instruments:</u>			
Enterprise Products Partners:			
Natural gas risk management activities (5,6)	526.8 Bcf	62.2 Bcf	Mark-to-market
NGL risk management activities (6)	0.7 MMBbls	n/a	Mark-to-market
Crude oil risk management activities (6)	1.0 MMBbls	n/a	Mark-to-market
Duncan Energy Partners:			
Natural gas risk management activities (6)	1.0 Bcf	n/a	Mark-to-market

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

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

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

(4) Excludes 1.5 MMBbls of additional hedges executed under contracts that have been designated as normal sales agreements under current accounting guidance. The combination of these volumes with the 5.1 MMBbls reflected as derivatives in the table above results in a total of 6.6 MMBbls of hedged forecasted NGL sales volumes, which corresponds to the 19.0 Bcf of forecasted natural gas purchase volumes for PTR.

(5) Current and long-term volumes include approximately 149.7 and 10.5 Bcf, respectively, of physical derivative instruments that are predominantly priced at an index plus a premium or minus a discount related to location differences.

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

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

§ The objective of our natural gas processing strategy is to hedge an amount of gross margin associated with our gas processing activities. We achieve this objective by using physical and financial instruments to lock in the purchase prices of natural gas consumed as PTR and the sales prices of the related NGL products. This program consists of (i) the forward sale of a portion of our expected equity NGL production at fixed prices through June 2011, which is achieved through the use of forward physical sales contracts and commodity derivative instruments and (ii) the purchase of commodity derivative instruments having a notional amount based on the volume of natural gas expected to be consumed as PTR in the production of such equity NGL production.

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

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

Foreign Currency Derivative Instruments

We are exposed to a nominal amount of foreign currency exchange risk in connection with our NGL and natural gas marketing activities in Canada. As a result, we could be adversely affected by fluctuations in currency values between the U.S. dollar and Canadian dollar. In order to manage this risk, we may enter into foreign exchange purchase contracts to lock in an exchange rate. Prior to the third quarter of 2010, long-term transactions (i.e., those having terms of more than two months) were accounted for as cash flow hedges and shorter term transactions were accounted for using mark-to-market accounting. We currently account for all foreign currency derivative transactions using mark-to-market accounting. At September 30, 2010, our foreign currency derivative instruments portfolio had a notional amount of $7.0 million Canadian. The fair market value of these derivative instruments was an asset of $0.1 million at September 30, 2010.

Credit-Risk Related Contingent Features in Derivative Instruments

A limited number of our commodity derivative instruments include provisions related to credit ratings and/or adequate assurance clauses. A credit rating provision provides for a counterparty to demand immediate full or partial payment to cover a net liability position upon the loss of a stipulated credit rating. An adequate assurance clause provides for a counterparty to demand immediate full or partial payment to cover a net liability position should reasonable grounds for insecurity arise with respect to contractual performance by either party. At September 30, 2010, the aggregate fair value of our over-the-counter derivative instruments in a net liability position was $2.5 million, all of which was subject to a credit rating continge nt feature. If our credit ratings were downgraded to Ba3/BB- or below, approximately $2.5 million would be payable as a margin deposit to the counterparties. Currently, no margin is required to be deposited. The potential for derivatives with contingent features to enter a net liability position may change in the future as commodity positions and prices fluctuate.

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

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

	Asset Derivatives				Liability Derivatives			
	September 30, 2010		December 31, 2009		September 30, 2010		December 31, 2009	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments								
Interest rate derivatives	Other current assets	$ 30.8	Other current assets	$ 32.7	Other current liabilities	$ 45.6	Other current liabilities	$ 18.6
Interest rate derivatives	Other assets	38.6	Other assets	31.8	Other liabilities	112.0	Other liabilities	6.7
Total interest rate derivatives		69.4		64.5		157.6		25.3
Commodity derivatives	Other current assets	29.9	Other current assets	52.0	Other current liabilities	63.8	Other current liabilities	62.6
Commodity derivatives	Other assets	2.7	Other assets	0.5	Other liabilities	2.9	Other liabilities	1.8
Total commodity derivatives (1)		32.6		52.5		66.7		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		$ 102.0		$ 117.2		$ 224.3		$ 89.7
Derivatives not designated as hedging instruments								
Commodity derivatives	Other current assets	$ 50.7	Other current assets	$ 28.9	Other current liabilities	$ 45.7	Other current liabilities	$ 24.9
Commodity derivatives	Other assets	3.9	Other assets	2.0	Other liabilities	8.1	Other liabilities	2.7
Total commodity derivatives		54.6		30.9		53.8		27.6
Foreign currency derivatives	Other assets	0.1	Other assets	--	Other liabilities	--	Other liabilities	--
Total derivatives not designated as hedging instruments		$ 54.7		$ 30.9		$ 53.8		$ 27.6

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

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

Derivatives in Fair Value Hedging Relationships	Location	Gain/(Loss) Recognized in Income on Derivative			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2010	2009	2010	2009
Interest rate derivatives	Interest expense	$ 8.1	$ 12.0	$ 27.1	$ (4.2)
Commodity derivatives	Revenue	6.1	0.6	9.0	(0.1)
Total		$ 14.2	$ 12.6	$ 36.1	$ (4.3)

Derivatives in Fair Value Hedging Relationships	Location	Gain/(Loss) Recognized in Income on Hedged Item			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2010	2009	2010	2009
Interest rate derivatives	Interest expense	$ (8.6)	$ (14.5)	$ (26.8)	$ 1.1
Commodity derivatives	Revenue	(7.0)	(0.5)	(9.4)	0.6
Total		$ (15.6)	$ (15.0)	$ (36.2)	$ 1.7

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

Derivatives in Cash Flow Hedging Relationships	Change in Value Recognized in Other Comprehensive Income on Derivative (Effective Portion)			
	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
Interest rate derivatives (1)	$ (81.6)	$ (11.3)	$ (168.4)	$ 3.0
Commodity derivatives – Revenue	(44.2)	(21.3)	42.2	44.5
Commodity derivatives – Operating costs and expenses	(19.9)	13.0	(73.2)	(191.4)
Foreign currency derivatives	0.1	0.2	(0.1)	(10.3)
Total	$ (145.6)	$ (19.4)	$ (199.5)	$ (154.2)

(1) Change in value due to increased notional amounts of forward starting swaps and the reduction of London Interbank Offered Rates ("LIBOR").

Derivatives in Cash Flow Hedging Relationships	Location	Gain/(Loss) Reclassified from Accumulated Other Comprehensive Income/Loss to Income (Effective Portion)			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2010	2009	2010	2009
Interest rate derivatives	Interest expense	$ (8.1)	$ (6.7)	$ (21.4)	$ (20.3)
Commodity derivatives	Revenue	39.2	(12.5)	41.7	7.2
Commodity derivatives	Operating costs and expenses	(13.6)	(65.3)	(31.1)	(183.5)
Foreign currency derivatives	Other income	--	--	0.3	--
Total		$ 17.5	$ (84.5)	$ (10.5)	$ (196.6)

Derivatives in Cash Flow Hedging Relationships	Location	Gain/(Loss) Recognized in Income on Ineffective Portion of Derivative			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2010	2009	2010	2009
Interest rate derivatives	Interest expense	$ --	$ 1.1	$ --	$ 0.8
Commodity derivatives	Revenue	--	0.8	--	0.1
Commodity derivatives	Operating costs and expenses	(0.4)	(1.0)	2.5	(2.3)
Total		$ (0.4)	$ 0.9	$ 2.5	$ (1.4)

Over the next twelve months, we expect to reclassify $24.9 million of losses attributable to interest rate derivative instruments from accumulated other comprehensive loss to earnings as an increase in interest expense. Likewise, we expect to reclassify $40.7 million of losses attributable to commodity derivative instruments from accumulated other comprehensive income to earnings, $21.9 million as an increase in operating costs and expenses and $18.8 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 as Hedging Instruments	Location	Gain/(Loss) Recognized in Income on Derivative			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2010	2009	2010	2009
Commodity derivatives	Revenue	$ 17.0	$ (5.4)	$ 12.0	$ 26.7
Commodity derivatives	Operating costs and expenses	--	--	(1.5)	--
Foreign currency derivatives	Other income	0.1	--	0.1	(0.1)
Total		$ 17.1	$ (5.4)	$ 10.6	$ 26.6

Fair Value Measurements

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

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

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

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

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

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

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

	At September 30, 2010			
	Level 1	Level 2	Level 3	Total
Financial assets:				
Interest rate derivatives	$ --	$ 69.4	$ --	$ 69.4
Commodity derivatives	32.7	37.1	17.4	87.2
Foreign currency derivatives	--	0.1	--	0.1
Total	$ 32.7	$ 106.6	$ 17.4	$ 156.7
Financial liabilities:				
Interest rate derivatives	$ --	$ 157.6	$ --	$ 157.6
Commodity derivatives	56.1	37.5	26.9	120.5
Total	$ 56.1	$ 195.1	$ 26.9	$ 278.1

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

	For the Nine Months Ended September 30,	
	2010	2009
Balance, January 1	$ 5.7	$ 32.4
Total gains (losses) included in:		
Net income (1)	(3.6)	12.9
Other comprehensive income (loss)	(8.3)	1.5
Purchases, issuances, settlements – net	3.6	(12.3)
Balance, March 31	(2.6)	34.5
Total gains (losses) included in:		
Net income (1)	16.2	7.7
Other comprehensive income (loss)	22.2	(23.1)
Purchases, issuances, settlements – net	(16.2)	(8.1)
Transfers out of Level 3	0.2	(0.2)
Balance, June 30	19.8	10.8
Total gains (losses) included in:		
Net income (1)	18.2	7.6
Other comprehensive income (loss)	(31.4)	(10.1)
Purchases, issuances, settlements – net	(16.1)	(6.7)
Transfers out of Level 3	--	(2.3)
Balance, September 30	$ (9.5)	$ (0.7)

(1) There were $6.4 million and $4.1 million of unrealized gains included in these amounts for the three and nine months ended September 30, 2010, respectively. There were $3.3 million and $3.5 million of unrealized losses included in these amounts for the three and nine months ended September 30, 2009, respectively.

Nonfinancial Assets and Liabilities

During the nine months ended September 30, 2010, certain pipeline assets recorded as property, plant and equipment were adjusted to fair value based on the present value of expected future cash flows (Level 3), resulting in nonrecurring fair value adjustments (i.e., non-cash asset impairment charges) totaling $1.5 million.

During the nine months ended September 30, 2009, certain river terminal and marine barge assets recorded as property, plant and equipment and other current assets were adjusted to fair value based on the present value of expected future cash flows (Level 3), resulting in non-cash asset impairment charges of $25.0 million. In addition, we recorded an impairment charge of $1.3 million related to goodwill during this period. These impairment charges resulted from reduced levels of throughput at the affected river terminals, the indefinite suspension of expansion plans for certain river terminals, and the determination that an underground gas storage cavern and certain marine transportation barges were obsolete. The affected river terminals were subject to a throughput contract with a third party. 60;See Note 15 for information regarding a related $28.7 million charge for deficiency fees related to the reduced levels of throughput at the affected river terminals.

The impairment charges we recorded during the nine months ended September 30, 2010 and 2009 are a component of operating costs and expenses.

Note 5. Inventories

Our inventory amounts were as follows at the dates indicated:

	September 30, 2010	December 31, 2009
Working inventory (1)	$ 788.9	$ 466.4
Forward sales inventory (2)	421.1	245.5
Total inventory	$ 1,210.0	$ 711.9

(1) Working inventory is comprised of natural gas, NGLs, crude oil, refined products, lubrication oils and certain petrochemical products that are either available-for-sale or used in the provision for services. The increase since December 31, 2009 is primarily related to increased marketing activities of refined products.

(2) Forward sales inventory consists of identified natural gas, NGL, refined product and crude oil volumes dedicated to the fulfillment of forward sales contracts. The increase since December 31, 2009 is primarily related to higher refined products forward sales volumes.

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

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
Cost of sales (1)	$ 6,814.0	$ 5,581.3	$ 20,499.5	$ 13,820.1
LCM adjustments	0.2	0.5	7.1	6.2

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

Note 6. Property, Plant and Equipment

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

	Estimated Useful Life in Years	September 30, 2010	December 31, 2009
Plants and pipelines (1)	3-45 (6)	$ 18,869.7	$ 17,681.9
Underground and other storage facilities (2)	5-40 (7)	1,426.6	1,280.5
Platforms and facilities (3)	20-31	637.6	637.6
Transportation equipment (4)	3-10	102.6	60.1
Marine vessels (5)	15-30	599.8	559.4
Land		91.7	82.9
Construction in progress		1,467.7	1,207.2
Total		23,195.7	21,509.6
Less accumulated depreciation		4,385.7	3,820.4
Property, plant and equipment, net		$ 18,810.0	$ 17,689.2

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

In May 2010, we recorded approximately $293.4 million of property, plant and equipment in connection with the acquisition of the State Line and Fairplay natural gas gathering systems from subsidiaries of M2 Midstream LLC ("Momentum"). See Note 8 for additional information regarding this business combination.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
Depreciation expense (1)	$ 184.9	$ 174.8	$ 552.9	$ 502.7
Capitalized interest (2)	12.5	11.4	33.5	39.5

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

Operating costs and expenses for the three and nine months ended September 30, 2010 include $9.9 million of non-cash charges resulting from the disposition of two pipeline segments in south Texas that were in natural gas gathering service.

Asset Retirement Obligations

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

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

ARO liability balance, December 31, 2009	$	54.8
Revisions in estimated cash flows		14.4
Accretion expense		3.0
Liabilities incurred during period		0.1
Liabilities settled during period		(8.1)
ARO liability balance, September 30, 2010	$	64.2

Property, plant and equipment at September 30, 2010 and December 31, 2009 includes $29.7 million and $26.7 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived assets. The following table presents forecasted accretion expense associated with our AROs for the periods indicated:

Remainder of 2010	2011	2012	2013	2014
$ 1.0	$ 4.1	$ 4.3	$ 4.6	$ 5.0

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

Note 7. Investments in Unconsolidated Affiliates

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

	Ownership Interest at September 30, 2010	September 30, 2010	December 31, 2009
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C.	13.1%	$ 31.8	$ 32.6
K/D/S Promix, L.L.C. (“Promix”)	50%	45.1	48.9
Baton Rouge Fractionators LLC	32.2%	22.0	22.2
Skelly-Belvieu Pipeline Company, L.L.C.	50%	33.8	37.9
Onshore Natural Gas Pipelines & Services:			
Evangeline (1)	49.5%	6.1	5.6
White River Hub, LLC	50%	26.5	26.4
Onshore Crude Oil Pipelines & Services:			
Seaway Crude Pipeline Company (“Seaway”)	50%	174.7	178.5
Offshore Pipelines & Services:			
Poseidon Oil Pipeline Company, L.L.C. (“Poseidon”)	36%	58.8	61.7
Cameron Highway Oil Pipeline Company	50%	233.3	239.6
Deepwater Gateway, L.L.C.	50%	99.1	101.8
Neptune Pipeline Company, L.L.C.	25.7%	54.2	53.8
Petrochemical & Refined Products Services:			
Baton Rouge Propylene Concentrator, LLC	30%	10.6	11.1
Centennial Pipeline LLC (“Centennial”)	50%	65.1	66.7
Other (2)	Various	3.6	3.8
Other Investments:			
Energy Transfer Equity	17.5%	1,455.0	1,513.5
LE GP	40.6%	11.5	12.1
Total		$ 2,331.2	$ 2,416.2

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

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

	September 30, 2010	December 31, 2009
NGL Pipelines & Services	$ 25.9	$ 27.1
Onshore Crude Oil Pipelines & Services	19.9	20.4
Offshore Pipelines & Services	16.4	17.3
Petrochemical & Refined Products Services	3.0	4.0
Other Investments (1)	1,545.5	1,573.0
Total	$ 1,610.7	$ 1,641.8

(1) The Parent Company’s initial investment in Energy Transfer Equity and LE GP exceeded its share of the historical cost of the underlying net assets of such investees by $1.67 billion. At September 30, 2010, this basis differential decreased to $1.55 billion (after taking into account related amortization amounts) and consisted of the following: $496.6 million attributed to fixed assets; $513.5 million attributed to the IDRs (an indefinite-life intangible asset) held by Energy Transfer Equity in the cash flows of ETP; $199.6 million attributed to amortizable intangible assets and $335.8 million attributed to equity method goodwill.

We amortize the excess cost amounts (as a reduction in equity earnings) in a manner similar to depreciation. The following table presents our amortization of such excess cost amounts by business segment for the periods indicated:

	For the Three Months Ended September 30, 2010	For the Three Months Ended September 30, 2009	For the Nine Months Ended September 30, 2010	For the Nine Months Ended September 30, 2009
NGL Pipelines & Services	$ 0.2	$ 0.2	$ 0.7	$ 0.7
Onshore Crude Oil Pipelines & Services	0.1	0.1	0.5	0.5
Offshore Pipelines & Services	0.3	0.3	0.9	0.9
Petrochemical & Refined Products Services	0.1	1.0	1.0	3.0
Other Investments	9.2	9.2	27.5	27.5
Total	$ 9.9	$ 10.8	$ 30.6	$ 32.6

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

	For the Three Months Ended September 30, 2010	For the Three Months Ended September 30, 2009	For the Nine Months Ended September 30, 2010	For the Nine Months Ended September 30, 2009
NGL Pipelines & Services	$ 5.1	$ 4.0	$ 12.1	$ 7.5
Onshore Natural Gas Pipelines & Services	1.2	1.4	3.4	3.9
Onshore Crude Oil Pipelines & Services	1.6	1.2	7.5	7.4
Offshore Pipelines & Services	10.1	10.6	33.0	22.1
Petrochemical & Refined Products Services	(0.5)	(2.2)	(5.8)	(8.9)
Other Investments	(11.9)	(0.9)	(7.0)	25.7
Total	$ 5.6	$ 14.1	$ 43.2	$ 57.7

Summarized Income Statement Information of Unconsolidated Affiliates

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

	Summarized Income Statement Information for the Three Months Ended					
	September 30, 2010			September 30, 2009		
	Revenues	Operating Income	Net Income (Loss)	Revenues	Operating Income	Net Income
NGL Pipelines & Services	$ 78.3	$ 17.3	$ 17.3	$ 60.0	$ 10.9	$ 11.2
Onshore Natural Gas Pipelines & Services	63.8	2.6	2.4	54.5	2.9	2.7
Onshore Crude Oil Pipelines & Services	16.6	5.8	5.8	20.7	6.9	6.8
Offshore Pipelines & Services	49.4	25.3	25.1	43.2	24.7	24.0
Petrochemical & Refined Products Services	15.1	2.5	0.2	12.8	2.4	--
Other Investments (1)	1,587.8	202.1	(15.3)	1,129.8	173.5	47.0

(1) Net income for Energy Transfer Equity represents net income attributable to the partners of Energy Transfer Equity.

	Summarized Income Statement Information for the Nine Months Ended					
	September 30, 2010			September 30, 2009		
	Revenues	Operating Income	Net Income (Loss)	Revenues	Operating Income	Net Income (Loss)
NGL Pipelines & Services	$ 227.8	$ 43.8	$ 43.7	$ 161.7	$ 23.7	$ 24.2
Onshore Natural Gas Pipelines & Services	159.8	7.0	6.7	137.1	8.0	7.6
Onshore Crude Oil Pipelines & Services	57.1	23.9	23.9	62.2	25.6	25.6
Offshore Pipelines & Services	155.8	81.3	80.5	106.4	39.2	37.7
Petrochemical & Refined Products Services	39.3	0.5	(6.6)	41.1	5.2	(2.5)
Other Investments (1)	4,822.3	720.2	116.7	3,911.5	744.6	302.9

(1) Net income for Energy Transfer Equity represents net income attributable to the partners of Energy Transfer Equity.

Note 8. Business Combinations

State Line and Fairplay Natural Gas Gathering Systems

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

The State Line system is located in Desoto and Caddo Parishes, Louisiana and Panola County, Texas. The system currently includes approximately 188 miles of natural gas gathering pipelines having an aggregate gathering capacity of approximately 700 million cubic feet per day ("MMcf/d") and two natural gas treating facilities. The State Line system began operations in February 2009 and is currently gathering approximately 375 MMcf/d of natural gas. The Fairplay system is located in Rusk, Panola, Gregg and Nacogdoches counties, Texas. The system includes approximately 249 miles of natural gas gathering pipelines having an aggregate gathering capacity of approximately 285 MMcf/d. The Fairplay system is currently gathering approximately 150 MMcf/d of natural gas. ;Our operations related to the Fairplay system include providing natural gas processing services using third-party processing facilities. The State Line and Fairplay systems are supported by long-term acreage dedication agreements totaling approximately 210,000 acres, as well as volumetric commitments from producers.

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

On a combined basis, our consolidated revenues and net income from the State Line and Fairplay systems were $75.0 million and $8.1 million, respectively, for the five months we owned these assets.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
Pro forma earnings data:				
Revenues	$ 8,067.8	$ 6,823.7	$ 24,221.1	$ 17,199.5
Costs and expenses	7,530.2	6,482.5	22,616.4	16,029.9
Operating income	543.2	355.3	1,647.9	1,227.3
Net income	347.6	175.4	1,098.9	389.7
Net income attributable to Enterprise GP Holdings L.P.	37.0	25.3	161.2	127.0
Basic earnings per unit:				
As reported basic units outstanding	139.2	139.2	139.2	137.4
Pro forma basic units outstanding	139.2	139.2	139.2	137.4
As reported basic earnings per unit	$ 0.27	$ 0.18	$ 1.16	$ 0.93
Pro forma basic earnings per unit	$ 0.27	$ 0.18	$ 1.16	$ 0.92
Diluted earnings per unit:				
As reported diluted units outstanding	139.2	139.2	139.2	137.4
Pro forma diluted units outstanding	139.2	139.2	139.2	137.4
As reported diluted earnings per unit	$ 0.27	$ 0.18	$ 1.16	$ 0.93
Pro forma diluted earnings per unit	$ 0.27	$ 0.18	$ 1.16	$ 0.92

Other 2010 Transactions

In June 2010, we acquired a marine transportation business located in south Louisiana for $12.0 million in cash. This business is engaged in crude oil gathering and included three tug boats and five barges. This business is part of our Petrochemical & Refined Products Services business segment. In August 2010, we acquired a crude oil trucking business located in North Dakota for $4.0 million. This business is part of our Onshore Crude Oil Pipelines & Services business segment. On a pro forma consolidated basis after giving effect to these two transactions, our revenues, costs and expenses, operating income, net income attributable to Enterprise GP Holdings L.P. and earnings per unit amounts would not have differed materially from those we reported for the three and nine months ended September 30, 2010 and 2009.

See Note 17 for information regarding a September 2010 drop down transaction whereby we acquired ownership interests in EPCO's trucking business.

Purchase Price Allocations

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

	State Line and Fairplay Systems	Other	Total
Assets acquired in business combination:			
Current assets	$ --	$ 1.6	$ 1.6
Property, plant and equipment, net	293.4	10.1	303.5
Identifiable intangible assets	895.0	--	895.0
Total assets acquired	1,188.4	11.7	1,200.1
Liabilities assumed in business combination:			
Current liabilities	--	(0.1)	(0.1)
Long-term debt	--	(1.3)	(1.3)
Other long-term liabilities	(0.1)	--	(0.1)
Total liabilities assumed	(0.1)	(1.4)	(1.5)
Total assets acquired plus liabilities assumed	1,188.3	10.3	1,198.6
Total cash used for business combinations	1,214.5	18.5	1,233.0
Goodwill (see Note 9)	$ 26.2	$ 8.2	$ 34.4

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

Note 9. Intangible Assets and Goodwill

Identifiable Intangible Assets

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

	September 30, 2010			December 31, 2009		
	Gross Value	Accum. Amort.	Carrying Value	Gross Value	Accum. Amort.	Carrying Value
NGL Pipelines & Services:						
Customer relationship intangibles (1)	$ 340.8	$ (101.3)	$ 239.5	$ 237.4	$ (86.5)	$ 150.9
Contract-based intangibles	321.9	(171.7)	150.2	321.4	(156.7)	164.7
Segment total	662.7	(273.0)	389.7	558.8	(243.2)	315.6
Onshore Natural Gas Pipelines & Services:						
Customer relationship intangibles (1)	1,163.6	(149.1)	1,014.5	372.0	(124.3)	247.7
Contract-based intangibles	565.3	(313.4)	251.9	565.3	(285.8)	279.5
Segment total	1,728.9	(462.5)	1,266.4	937.3	(410.1)	527.2
Onshore Crude Oil Pipelines & Services:						
Customer relationship intangibles	9.6	(3.7)	5.9	9.6	(3.4)	6.2
Contract-based intangibles	0.4	(0.1)	0.3	0.4	(0.1)	0.3
Segment total	10.0	(3.8)	6.2	10.0	(3.5)	6.5
Offshore Pipelines & Services:						
Customer relationship intangibles	205.8	(115.0)	90.8	205.8	(105.3)	100.5
Contract-based intangibles	1.2	(0.2)	1.0	1.2	(0.2)	1.0
Segment total	207.0	(115.2)	91.8	207.0	(105.5)	101.5
Petrochemical & Refined Products Services:						
Customer relationship intangibles	104.7	(22.5)	82.2	104.6	(18.8)	85.8
Contract-based intangibles	41.7	(17.7)	24.0	42.1	(13.9)	28.2
Segment total	146.4	(40.2)	106.2	146.7	(32.7)	114.0
Total all segments	$ 2,755.0	$ (894.7)	$ 1,860.3	$ 1,859.8	$ (795.0)	$ 1,064.8

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

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
NGL Pipelines & Services	$ 10.4	$ 9.4	$ 29.8	$ 27.6
Onshore Natural Gas Pipelines & Services	20.1	13.9	52.4	43.4
Onshore Crude Oil Pipelines & Services	0.1	0.1	0.3	0.3
Offshore Pipelines & Services	3.1	3.6	9.7	11.2
Petrochemical & Refined Products Services	2.7	2.7	7.9	8.0
Total	$ 36.4	$ 29.7	$ 100.1	$ 90.5

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

Remainder of 2010	2011	2012	2013	2014
$ 36.0	$ 143.7	$ 135.3	$ 135.0	$ 137.0

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

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 (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 September 30, 2010, the carrying value of our customer relationship intangible assets was $1.43 billion.

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

	Gross Value	Accum. Amort.	Carrying Value
State Line natural gas gathering customer relationships (1)	$ 675.0	$ (7.4)	$ 667.6
Fairplay natural gas gathering customer relationships (1)	116.6	(2.7)	113.9
Fairplay natural gas processing customer relationships (2)	103.4	(2.4)	101.0
Total acquired customer relationships	$ 895.0	$ (12.5)	$ 882.5

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

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

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

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

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

Contract-based intangible assets. Contract-based intangible assets represent specific commercial rights we acquired in connection with business combinations or asset purchases. At September 30, 2010, the carrying value of our contract-based intangible assets was $427.4 million.

Goodwill

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

	NGL Pipelines & Services	Onshore Natural Gas Pipelines & Services	Onshore Crude Oil Pipelines & Services	Offshore Pipelines & Services	Petrochemical & Refined Products Services	Consolidated Totals
Balance at December 31, 2009 (1)	$ 341.2	$ 284.9	$ 303.0	$ 82.1	$ 1,007.1	$ 2,018.3
Goodwill related to acquisitions	--	26.2	8.2	--	--	34.4
Balance at September 30, 2010 (1)	$ 341.2	$ 311.1	$ 311.2	$ 82.1	$ 1,007.1	$ 2,052.7

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

In May 2010, we recorded $26.2 million of goodwill in connection with our acquisition of the State Line and Fairplay natural gas gathering systems. In June 2010, we recorded $6.1 million of goodwill related to our acquisition of a marine transportation business that provides crude oil gathering services in south Louisiana. In August 2010, we recorded $2.1 million of goodwill related to our acquisition of a crude oil trucking business based in North Dakota. We attribute these goodwill amounts to our ability to leverage the acquired businesses with our existing asset base to create future business opportunities.

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

Note 10. Debt Obligations

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

	September 30, 2010	December 31, 2009
Parent Company debt obligations:		
EPE Revolver, variable-rate, due August 2012	$ 127.3	$ 123.5
$125.0 million Term Loan A, variable rate, due August 2012	125.0	125.0
$850.0 million Term Loan B, variable rate, due November 2014 (1)	833.0	833.0
EPO senior debt obligations:		
Multi-Year Revolving Credit Facility, variable-rate, due November 2012	35.0	195.5
Pascagoula MBFC Loan, 8.70% fixed-rate, due March 2010	--	54.0
Petal GO Zone Bonds, variable-rate, due August 2034	57.5	57.5
Senior Notes B, 7.50% fixed-rate, due February 2011 (1)	450.0	450.0
Senior Notes C, 6.375% fixed-rate, due February 2013	350.0	350.0
Senior Notes D, 6.875% fixed-rate, due March 2033	500.0	500.0
Senior Notes G, 5.60% fixed-rate, due October 2014	650.0	650.0
Senior Notes H, 6.65% fixed-rate, due October 2034	350.0	350.0
Senior Notes I, 5.00% fixed-rate, due March 2015	250.0	250.0
Senior Notes J, 5.75% fixed-rate, due March 2035	250.0	250.0
Senior Notes K, 4.95% fixed-rate, due June 2010	--	500.0
Senior Notes L, 6.30% fixed-rate, due September 2017	800.0	800.0
Senior Notes M, 5.65% fixed-rate, due April 2013	400.0	400.0
Senior Notes N, 6.50% fixed-rate, due January 2019	700.0	700.0
Senior Notes O, 9.75% fixed-rate, due January 2014	500.0	500.0
Senior Notes P, 4.60% fixed-rate, due August 2012	500.0	500.0
Senior Notes Q, 5.25% fixed-rate, due January 2020	500.0	500.0
Senior Notes R, 6.125% fixed-rate, due October 2039	600.0	600.0
Senior Notes S, 7.625% fixed-rate, due February 2012	490.5	490.5
Senior Notes T, 6.125% fixed-rate, due February 2013	182.5	182.5
Senior Notes U, 5.90% fixed-rate, due April 2013	237.6	237.6
Senior Notes V, 6.65% fixed-rate, due April 2018	349.7	349.7
Senior Notes W, 7.55% fixed-rate, due April 2038	399.6	399.6
Senior Notes X, 3.70% fixed-rate, due June 2015	400.0	--
Senior Notes Y, 5.20% fixed-rate, due September 2020	1,000.0	--
Senior Notes Z, 6.45% fixed-rate, due September 2040	600.0	--
TEPPCO senior debt obligations:		
TEPPCO Senior Notes	40.1	40.1
Duncan Energy Partners' debt obligations:		
DEP Revolving Credit Facility, variable-rate, due February 2011 (1)	247.5	175.0
DEP Term Loan, variable-rate, due December 2011	282.3	282.3
Total principal amount of senior debt obligations	12,207.6	10,845.8
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	13,740.3	12,378.5
Other, non-principal amounts:		
Change in fair value of debt-related derivative instruments (2)	59.9	44.4
Unamortized discounts, net of premiums	(24.4)	(18.7)
Unamortized deferred net gains related to terminated interest rate swaps (2)	14.3	23.7
Total other, non-principal amounts	49.8	49.4
Total long-term debt	$ 13,790.1	$ 12,427.9

(1) Long-term and current maturities of debt reflect the classification of such obligations at September 30, 2010. With respect to an $8.5 million current maturity due under Term Loan B, the Parent Company has the ability to use available long-term credit capacity under the EPE Revolver to fund repayment of this amount. In addition, EPO has the ability to use available forecast long-term borrowing capacity under its $1.75 billion Multi-Year Revolving Credit Facility to satisfy the current maturity of Senior Notes B and Duncan Energy Partners has the ability to use its available capacity after giving effect to the refinancing in October 2010 of its existing revolving credit facility on a long-term basis. See "— Debt Obligations — Duncan Energy Partners' debt obligations" below in this footnote.

(2) See Note 4 for information regarding our interest rate hedging activities.

Letters of Credit

At September 30, 2010, EPO had a $50.0 million letter of credit outstanding related to its commodity derivative instruments and a $58.3 million letter of credit outstanding related to its Petal GO Zone Bonds. These letter of credit facilities do not reduce the amount available for borrowing under EPO's Multi-Year Revolving Credit Facility.

Subsidiary Guarantor Relationships

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

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

Debt Obligations

The Parent Company consolidates the debt obligations of Enterprise Products Partners; however, the Parent Company does not have the obligation to make interest or debt payments with respect to such consolidated debt obligations.

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

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

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

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

Duncan Energy Partners' debt obligations. On October 25, 2010, Duncan Energy Partners entered into new long-term variable rate senior unsecured credit facilities having an aggregate borrowing capacity of $1.25 billion. The new Duncan Energy Partners credit facilities mature in October 2013 and consist of (i) an $850.0 million multi-year revolving credit facility (the "DEP Multi-Year Revolving Credit Facility") and (ii) a $400.0 million term loan facility (the "DEP $400 Million Term Loan Facility"). At closing, Duncan Energy Partners borrowed the full amount available under the DEP $400 Million Term Loan Facility to repay amou nts outstanding under the DEP Revolving Credit Facility and an intercompany loan with EPO (eliminated in consolidation). Upon repayment, the DEP Revolving Credit Facility along with the loan agreement with EPO were terminated. Duncan Energy Partners' existing $282.3 million DEP Term Loan remains in place and is scheduled to mature in December 2011.

Duncan Energy Partners entered into the new $1.25 billion credit agreements primarily to provide its share of the funding requirements for the Haynesville Extension project under the Amended Acadian LLC Agreement (see Note 13). Variable interest rates charged under the new credit facilities are based on LIBOR or a base rate, both as defined in the agreement.

Covenants

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

Information Regarding Variable Interest Rates Paid

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

	Range of Interest Rates Paid	Weighted-Average Interest Rate Paid
EPE Revolver	1.23% to 3.25%	1.28%
EPE Term Loan A	1.23% to 1.53%	1.35%
EPE Term Loan B	2.48% to 2.78%	2.60%
EPO Multi-Year Revolving Credit Facility	0.73% to 3.25%	0.84%
DEP Revolving Credit Facility	0.80% to 1.19%	0.94%
DEP Term Loan	0.93% to 1.09%	1.00%
Petal GO Zone Bonds	0.12% to 0.30%	0.24%

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	$ 409.8	$ --	$ 247.5	$ 162.3	$ --	$ --	$ --
Senior Notes	10,500.0	--	450.0	1,000.0	1,200.0	1,150.0	6,700.0
Term Loans	1,240.3	8.5	290.8	133.5	8.5	799.0	--
Junior Subordinated Notes	1,532.7	--	--	--	--	--	1,532.7
Other	57.5	--	--	--	--	--	57.5
Total	$ 13,740.3	$ 8.5	$ 988.3	$ 1,295.8	$ 1,208.5	$ 1,949.0	$ 8,290.2

Long-term and current maturities of debt reflect the classification of such obligations at September 30, 2010. With respect to the $8.5 million due under Term Loan B, the Parent Company has the ability to use available long-term credit capacity under the EPE Revolver to fund repayment of this amount. In addition, EPO has the 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 the refinancing by Duncan Energy Partners in October 2010 of its existing revolving credit facility on a long-term basis.

Debt Obligations of Unconsolidated Affiliates

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

			Scheduled Maturities of Debt					
	Ownership Interest	Total	Remainder of 2010	2011	2012	2013	2014	After 2014
Poseidon	36%	$ 92.0	$ --	$ 92.0	$ --	$ --	$ --	$ --
Evangeline	49.5%	6.4	3.2	3.2	--	--	--	--
Centennial	50%	113.2	2.3	9.0	8.9	8.6	8.6	75.8
Total		$ 211.6	$ 5.5	$ 104.2	$ 8.9	$ 8.6	$ 8.6	$ 75.8

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

There have been no significant changes in the terms of the debt obligations of our privately held unconsolidated affiliates since those reported in our 2009 Form 10-K.

At September 30, 2010 and December 31, 2009, Energy Transfer Equity had approximately $8.8 billion and $7.8 billion of consolidated debt obligations outstanding. The majority of these amounts relate to senior note obligations of Energy Transfer Equity and ETP and revolving credit agreements of ETP and RGNC. Based on information contained in the SEC filings of Energy Transfer Equity, the future maturities of their consolidated long-term debt at September 30, 2010 are as follows: $3.1 million, 2010 (remainder); $34.7 million, 2011; $423.0 billion, 2012; $730.2 million, 2013; $818.7 million, 2014 and $6.8 billion, thereafter.

Note 11. Equity and Distributions

Our 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 First Amended and Restated Agreement of Limited Partnership (as amended from time to time, the "Partnership Agreement").

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

Registration Statement

The Parent Company has a universal shelf registration statement on file with the SEC that allows it to issue an unlimited amount of debt and equity securities for general partnership purposes. As of September 30, 2010, the Parent Company had not issued any securities under its universal shelf registration statement.

Unit History

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

Balance, December 31, 2009	139,191,640
Restricted units granted and immediately vested	3,424
Balance, September 30, 2010	139,195,064

Distributions to Partners

The Parent Company's cash distribution policy is consistent with the terms of its Partnership Agreement, which requires it to distribute its available cash (as defined in our Partnership Agreement) to its partners no later than 50 days after the end of each fiscal quarter. The quarterly cash distributions are not cumulative.

The following table presents the Parent Company's declared quarterly cash distribution rates per Unit since the first quarter of 2009 and the related record and distribution payment dates. The quarterly cash distribution rates per Unit correspond to the fiscal quarters indicated.

	Distribution per Unit	Record Date	Payment Date
2009			
1st Quarter	$ 0.485	Apr. 30, 2009	May 11, 2009
2nd Quarter	$ 0.500	Jul. 31, 2009	Aug. 10, 2009
3rd Quarter	$ 0.515	Oct. 30, 2009	Nov. 6, 2009
4th Quarter	$ 0.530	Jan. 29, 2010	Feb. 5, 2010
2010			
1st Quarter	$ 0.545	Apr. 30, 2010	May 7, 2010
2nd Quarter	$ 0.560	Jul. 30, 2010	Aug. 6, 2010
3rd Quarter	$ 0.575	Oct. 29, 2010	Nov. 9, 2010

Accumulated Other Comprehensive Income (Loss)

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

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

	September 30, 2010	December 31, 2009
Commodity derivative instruments (1)	$ (41.1)	$ 0.5
Interest rate derivative instruments (1)	(174.6)	(27.6)
Foreign currency derivative instruments (1)	--	0.4
Foreign currency translation adjustment (2)	1.1	0.8
Pension and postretirement benefit plans	(1.7)	(0.8)
Proportionate share of other comprehensive loss of unconsolidated affiliates, primarily Energy Transfer Equity	0.3	(11.2)
Subtotal	(216.0)	(37.9)
Amounts attributable to noncontrolling interests	170.0	4.6
Total accumulated other comprehensive loss in partners' equity	$ (46.0)	$ (33.3)

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

Noncontrolling Interests

Prior to the completion of the TEPPCO Merger, we accounted for the economic interest of the former owners of TEPPCO and TEPPCO GP within noncontrolling interests. Under this method of presentation, all pre-merger revenues and expenses of TEPPCO and TEPPCO GP are included in net income, and the former owners' share of the income of TEPPCO and TEPPCO GP is allocated to net income attributable to noncontrolling interest.

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

	September 30, 2010	December 31, 2009
Limited partners of Enterprise Products Partners:		
Third-party owners of Enterprise Products Partners (1)	$ 7,789.6	$ 7,001.6
Related party owners of Enterprise Products Partners (2)	1,163.2	1,003.6
Limited partners of Duncan Energy Partners:		
Third-party owners of Duncan Energy Partners (1)	410.3	414.3
Related party owners of Duncan Energy Partners (2)	1.7	1.7
Joint venture partners (3)	116.5	117.4
Accumulated other comprehensive loss attributable to noncontrolling interest	(170.0)	(4.6)
Total	$ 9,311.3	$ 8,534.0

(1) Consists of non-affiliate public unitholders of Enterprise Products Partners and Duncan Energy Partners.
(2) Consists of unitholders of Enterprise Products Partners and Duncan Energy Partners that are related party affiliates of the Parent Company. This group is primarily comprised of EPCO and certain of its private company consolidated subsidiaries.
(3) 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 (loss) attributable to noncontrolling interests as presented on our Unaudited Condensed Statements of Consolidated Operations for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
Limited partners of Enterprise Products Partners	$ 296.6	$ 166.2	$ 887.3	$ 489.5
Limited partners of Duncan Energy Partners	8.5	10.1	26.8	21.8
Former owners of TEPPCO (1)	--	(33.6)	--	37.3
Joint venture partners	5.5	6.9	19.3	20.7
Total	$ 310.6	$ 149.6	$ 933.4	$ 569.3

(1) TEPPCO recorded $51.0 million in charges during the three months ended September 30, 2009 primarily related to the indefinite suspension of certain river terminal projects (see Note 4).

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 Nine Months Ended September 30,	
	2010	2009
Cash distributions paid to noncontrolling interests:		
Limited partners of Enterprise Products Partners	$ 1,045.0	$ 713.8
Limited partners of Duncan Energy Partners	32.1	23.2
Limited partners of TEPPCO	--	218.4
Joint venture partners	21.9	24.6
Total cash distributions paid to noncontrolling interests	$ 1,099.0	$ 980.0
Cash contributions from noncontrolling interests:		
Limited partners of Enterprise Products Partners	$ 1,031.6	$ 853.2
Limited partners of Duncan Energy Partners	1.2	137.4
Limited partners of TEPPCO	--	3.5
Joint venture partners	1.6	(2.2)
Total cash contributions from noncontrolling interests	$ 1,034.4	$ 991.9

Cash distributions paid to the limited partners of Enterprise Products Partners, Duncan Energy Partners and TEPPCO (prior to the completion of the TEPPCO Merger on October 26, 2009) represent the quarterly cash distributions paid by these entities to their unitholders, excluding those paid to the Parent Company.

Cash contributions received from the limited partners of Enterprise Products Partners, Duncan Energy Partners and TEPPCO (prior to the completion of the TEPPCO Merger) represent net cash proceeds each entity received from the issuance of limited partner units, excluding those received from the Parent Company.

During the nine months ended September 30, 2010, Enterprise Products Partners issued an aggregate of 31,465,652 of its common units, which generated net cash proceeds of approximately $1.06 billion. Enterprise Products Partners used the net cash proceeds received from the issuance of limited partner units during 2010 to (i) fund a portion of the cash consideration paid to acquire the State Line and Fairplay systems in May 2010 (see Note 8), (ii) temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and (iii) for general partnership purposes. During the nine months ended September 30, 2009, Enterprise Products Partners issued an aggregate of 35,740,690 of its common units, which generated net cash proceeds of approximately $877.7 million. Enterprise Products Pa rtners used the net cash proceeds received from the issuance of limited partner units during 2009 to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes.

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

Note 12. Business Segments

We have six reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services; (v) Petrochemical & Refined Products Services and (vi) Other Investments. 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 operati ng income.

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

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

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
Revenues	$ 8,067.8	$ 6,789.4	$ 24,155.7	$ 17,110.6
Less: Operating costs and expenses	(7,460.1)	(6,395.8)	(22,406.2)	(15,796.9)
Add: Equity in income of unconsolidated affiliates	5.6	14.1	43.2	57.7
Depreciation, amortization and accretion in operating costs and expenses (1)	235.1	206.0	674.5	602.9
Non-cash asset impairment charges	--	24.0	1.5	26.3
Operating lease expenses paid by EPCO	0.2	0.2	0.5	0.5
Gains from asset sales and related transactions in operating costs and expenses (2)	(39.7)	(0.1)	(45.3)	(0.5)
Total segment gross operating margin	$ 808.9	$ 637.8	$ 2,423.9	$ 2,000.6

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

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
Total segment gross operating margin	$ 808.9	$ 637.8	$ 2,423.9	$ 2,000.6
Adjustments to reconcile total segment gross operating margin to operating income:				
Depreciation, amortization and accretion in operating costs and expenses	(235.1)	(206.0)	(674.5)	(602.9)
Non-cash asset impairment charges	--	(24.0)	(1.5)	(26.3)
Operating lease expenses paid by EPCO	(0.2)	(0.2)	(0.5)	(0.5)
Gains from asset sales and related transactions in operating costs and expenses	39.7	0.1	45.3	0.5
General and administrative costs	(70.1)	(54.3)	(150.9)	(142.0)
Operating income	543.2	353.4	1,641.8	1,229.4
Other expense, net	(190.7)	(170.8)	(527.3)	(506.0)
Income before provision for income taxes	$ 352.5	$ 182.6	$ 1,114.5	$ 723.4

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	Other Investments	Adjustments and Eliminations	Consolidated Totals
Revenues from third parties:								
Three months ended September 30, 2010	$ 3,169.3	$ 781.8	$ 2,726.0	$ 68.3	$ 1,188.7	$ --	$ --	$ 7,934.1
Three months ended September 30, 2009	3,141.7	708.1	2,007.0	101.7	720.5	--	--	6,679.0
Nine months ended September 30, 2010	9,759.4	2,679.1	7,742.0	240.3	3,252.8	--	--	23,673.6
Nine months ended September 30, 2009	7,767.6	2,007.6	5,003.1	247.5	1,662.6	--	--	16,688.4
Revenues from related parties:								
Three months ended September 30, 2010	65.2	66.1	(0.1)	2.5	--	--	--	133.7
Three months ended September 30, 2009	47.2	60.2	3.0	--	--	--	--	110.4
Nine months ended September 30, 2010	300.7	175.2	(0.2)	6.4	--	--	--	482.1
Nine months ended September 30, 2009	245.3	173.1	3.8	--	--	--	--	422.2
Intersegment and intrasegment revenues:								
Three months ended September 30, 2010	2,378.1	261.0	313.4	0.5	309.7	--	(3,262.7)	--
Three months ended September 30, 2009	1,640.5	125.5	11.1	0.4	158.6	--	(1,936.1)	--
Nine months ended September 30, 2010	7,333.0	689.3	561.5	1.2	854.7	--	(9,439.7)	--
Nine months ended September 30, 2009	4,535.5	392.8	34.7	1.0	393.8	--	(5,357.8)	--
Total revenues:								
Three months ended September 30, 2010	5,612.6	1,108.9	3,039.3	71.3	1,498.4	--	(3,262.7)	8,067.8
Three months ended September 30, 2009	4,829.4	893.8	2,021.1	102.1	879.1	--	(1,936.1)	6,789.4
Nine months ended September 30, 2010	17,393.1	3,543.6	8,303.3	247.9	4,107.5	--	(9,439.7)	24,155.7
Nine months ended September 30, 2009	12,548.4	2,573.5	5,041.6	248.5	2,056.4	--	(5,357.8)	17,110.6
Equity in income (loss) of unconsolidated affiliates:								
Three months ended September 30, 2010	5.1	1.2	1.6	10.1	(0.5)	(11.9)	--	5.6
Three months ended September 30, 2009	4.0	1.4	1.2	10.6	(2.2)	(0.9)	--	14.1
Nine months ended September 30, 2010	12.1	3.4	7.5	33.0	(5.8)	(7.0)	--	43.2
Nine months ended September 30, 2009	7.5	3.9	7.4	22.1	(8.9)	25.7	--	57.7
Gross operating margin:								
Three months ended September 30, 2010	397.2	154.1	35.0	68.3	166.2	(11.9)	--	808.9
Three months ended September 30, 2009	403.4	108.4	34.1	22.8	70.0	(0.9)	--	637.8
Nine months ended September 30, 2010	1,275.5	391.3	87.6	232.2	444.3	(7.0)	--	2,423.9
Nine months ended September 30, 2009	1,118.1	391.5	126.7	83.0	255.6	25.7	--	2,000.6
Segment assets:								
At September 30, 2010	7,388.7	8,147.0	899.5	2,033.3	3,651.5	1,466.5	1,467.7	25,054.2
At December 31, 2009	7,191.2	6,918.7	865.4	2,121.4	3,359.0	1,525.6	1,207.2	23,188.5
Property, plant and equipment, net: (see Note 6)								
At September 30, 2010	6,525.1	6,536.9	407.4	1,414.0	2,458.9	--	1,467.7	18,810.0

At December 31, 2009	6,392.8	6,074.6	377.4	1,480.9	2,156.3	--	1,207.2	17,689.2
Investments in unconsolidated affiliates: (see Note 7)								
At September 30, 2010	132.7	32.6	174.7	445.4	79.3	1,466.5	--	2,331.2
At December 31, 2009	141.6	32.0	178.5	456.9	81.6	1,525.6	--	2,416.2
Intangible assets, net: (see Note 9)								
At September 30, 2010	389.7	1,266.4	6.2	91.8	106.2	--	--	1,860.3
At December 31, 2009	315.6	527.2	6.5	101.5	114.0	--	--	1,064.8
Goodwill: (see Note 9)								
At September 30, 2010	341.2	311.1	311.2	82.1	1,007.1	--	--	2,052.7
At December 31, 2009	341.2	284.9	303.0	82.1	1,007.1	--	--	2,018.3

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

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
NGL Pipelines & Services:				
Sales of NGLs	$ 3,048.0	$ 3,015.4	$ 9,516.5	$ 7,527.6
Sales of other petroleum and related products	0.6	0.6	1.8	1.5
Midstream services	185.9	172.9	541.8	483.8
Total	3,234.5	3,188.9	10,060.1	8,012.9
Onshore Natural Gas Pipelines & Services:				
Sales of natural gas	651.0	585.8	2,281.8	1,639.5
Midstream services	196.9	182.5	572.5	541.2
Total	847.9	768.3	2,854.3	2,180.7
Onshore Crude Oil Pipelines & Services:				
Sales of crude oil	2,701.4	1,991.3	7,672.1	4,946.1
Midstream services	24.5	18.7	69.7	60.8
Total	2,725.9	2,010.0	7,741.8	5,006.9
Offshore Pipelines & Services:				
Sales of natural gas	0.2	0.3	1.0	0.9
Sales of crude oil	2.3	2.0	6.3	3.1
Midstream services	68.3	99.4	239.4	243.5
Total	70.8	101.7	246.7	247.5
Petrochemical & Refined Products Services:				
Sales of other petroleum and related products	1,056.3	597.2	2,860.6	1,272.0
Midstream services	132.4	123.3	392.2	390.6
Total	1,188.7	720.5	3,252.8	1,662.6
Total consolidated revenues	$ 8,067.8	$ 6,789.4	$ 24,155.7	$ 17,110.6
Consolidated cost and expenses:				
Operating costs and expenses:				
Cost of sales related to our marketing activities	$ 6,234.5	$ 5,026.6	$ 18,577.2	$ 12,302.5
Depreciation, amortization and accretion	235.1	206.0	674.5	602.9
Gains from asset sales and related transactions	(39.7)	(0.1)	(45.3)	(0.5)
Non-cash asset impairment charges	--	24.0	1.5	26.3
Other operating costs and expenses	1,030.2	1,139.3	3,198.3	2,865.7
General and administrative costs	70.1	54.3	150.9	142.0
Total consolidated costs and expenses	$ 7,530.2	$ 6,450.1	$ 22,557.1	$ 15,938.9

Note 13. Related Party Transactions

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

	For the Three Months Ended September 30, 2010	For the Three Months Ended September 30, 2009	For the Nine Months Ended September 30, 2010	For the Nine Months Ended September 30, 2009
Revenues – related parties:				
Energy Transfer Equity and subsidiaries	$ 66.2	$ 54.5	$ 312.7	$ 266.5
Unconsolidated affiliates	67.5	55.9	169.4	155.7
Total revenue – related parties	$ 133.7	$ 110.4	$ 482.1	$ 422.2
Costs and expenses – related parties:				
EPCO and affiliates	$ 201.3	$ 164.9	$ 525.7	$ 461.1
Energy Transfer Equity and subsidiaries	172.6	113.1	496.7	310.1
Unconsolidated affiliates	10.4	9.1	32.1	22.8
Other	--	6.5	--	35.1
Total costs and expenses – related parties	$ 384.3	$ 293.6	$ 1,054.5	$ 829.1

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

	September 30, 2010	December 31, 2009
Accounts receivable - related parties:		
Energy Transfer Equity and subsidiaries	$ 9.3	$ 28.2
Other	21.7	10.2
Total accounts receivable – related parties	$ 31.0	$ 38.4
Accounts payable - related parties:		
EPCO and affiliates	$ 50.6	$ 27.8
Energy Transfer Equity and subsidiaries	39.3	33.4
Other	9.1	9.6
Total accounts payable – related parties	$ 99.0	$ 70.8

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; and

§ EPE Holdings, our sole general partner.

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

	Number of Units	Percentage of Outstanding Units
Enterprise Products Partners L.P. (1,2)	198,630,738	30.9%
Parent Company (3)	106,648,357	76.6%

(1) Includes 4,520,431 Class B units owned by a privately held affiliate of EPCO, 21,563,177 common units owned by the Parent Company, and 523,306 common units issued to EPCO in September 2010.
(2) The Parent Company owns 100% of Enterprise Products Partners' general partner, EPGP.
(3) Dan Duncan LLC owns 100% of the member interests of our general partner.

The principal business activity of EPE Holdings and EPGP is to act as the sole managing partner of the Parent Company and Enterprise Products Partners, respectively. The executive officers and certain of the directors of EPGP and EPE Holdings are employees of EPCO.

The Parent Company, EPE Holdings, Enterprise Products Partners and EPGP are separate legal entities apart from each other and apart from EPCO and their respective other affiliates, with assets and liabilities that are separate from those of EPCO and their respective other affiliates. EPCO and its privately held affiliates depend on the cash distributions they receive from the Parent Company, Enterprise Products Partners 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 the Parent Company and Enterprise Products Partners for the periods indicated:

	For the Nine Months Ended September 30,	
	2010	2009
Enterprise Products Partners	$ 255.1	$ 232.6
Parent Company	176.6	149.6
Total distributions	$ 431.7	$ 382.2

Substantially all of the ownership interests in Enterprise Products Partners that are owned or controlled by the Parent Company are pledged as security under the Parent Company's credit facility. In addition, substantially all of the ownership interests in the Parent Company and Enterprise Products Partners that are owned or controlled by EPCO and its affiliates, other than those interests owned by the Parent Company, Dan Duncan LLC and certain trusts of which the estate of Mr. 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 the Parent Company and Enterprise Products Partners.

We 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. The Parent Company, Enterprise Products Partners, Duncan Energy Partners and our respective general partners are parties to the ASA. The significant terms of the ASA are as follows:

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

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

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

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

Our operating costs and expenses include amounts paid to EPCO for the costs it incurs to operate our facilities, including the compensation of employees. We reimburse EPCO for actual direct and indirect expenses it incurs related to the operation of our assets. Our general and administrative costs include amounts paid to EPCO for administrative services, including the compensation of employees. In general, our reimbursement to EPCO for administrative services is either (i) on an actual basis for direct expenses it may incur on our behalf (e.g., the purchase of office supplies) or (ii) based on an allocation of such charges between the various parties to the ASA based on the estimated use of such services by each party (e.g., the allocation of legal or accounting salaries based on estimates of time spent on each e ntity'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 September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
Operating costs and expenses	$ 159.4	$ 139.4	$ 434.7	$ 384.6
General and administrative expenses	41.9	25.5	91.0	76.5
Total costs and expenses	$ 201.3	$ 164.9	$ 525.7	$ 461.1

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 the Parent Company (including EPE Holdings), Enterprise Products Partners (including EPGP), 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 the Parent Company, Enterprise Products Partners, Duncan Energy Partners and their respective general partners.

Acquisition of EPCO's Trucking Business. Historically, EPCO has provided us with tank truck services for the transportation of NGLs and other products. In September 2010, we acquired EPCO's ownership interests in its trucking business, or ETC, in exchange for 523,306 of Enterprise Products Partners' common units. Since we and EPCO are under common control, we recorded the net assets of ETC based on EPCO's historical basis of $30.6 million. The equity consideration issued was based on the average closing price of Enterprise Products Partners' common units over a 20-day period ending September 28, 2010.

Relationships with Unconsolidated Affiliates

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

§ We sell natural gas to Evangeline, which, in turn, uses the natural gas to satisfy supply commitments it has with a major Louisiana utility. Revenues from Evangeline were $58.9 million and $49.8 million for the three months ended September 30, 2010 and 2009, respectively. During the nine months ended September 30, 2010 and 2009, revenues from Evangeline were $145.7 million and $143.3 million, respectively.

§ We pay Promix for the transportation, storage and fractionation of NGLs. In addition, we sell natural gas to Promix for its plant fuel requirements. Revenues from Promix were $3.7 million and $2.6 million for the three months ended September 30, 2010 and 2009, respectively. During the nine months ended September 30, 2010 and 2009, revenues from Promix were $9.9 million and $7.7 million, respectively. Expenses with Promix were $9.7 million and $7.7 million for the three months ended September 30, 2010 and 2009, respectively. During the nine months ended September 30, 2010 and 2009, expenses with Promix were $25.8 million and $18.7 million, respectively.

§ We paid $0.2 million and $1.1 million to Centennial for pipeline transportation services during the three months ended September 30, 2010 and 2009, respectively. During the nine months ended September 30, 2010 and 2009, we paid Centennial $3.1 million and $3.5 million, respectively, for such services.

§ We paid $0.8 million and $1.4 million to Seaway for pipeline transportation and tank rentals during the three months ended September 30, 2010 and 2009, respectively. During the nine months ended September 30, 2010 and 2009, we paid Seaway $3.5 million and $4.0 million, respectively, for such services.

§ We perform management services for certain of our unconsolidated affiliates. We charged such affiliates $2.9 million and $2.7 million for the three months ended September 30, 2010 and 2009, respectively. During the nine months ended September 30, 2010 and 2009, we charged affiliates $8.6 million and $8.0 million, respectively.

§ Enterprise Products Partners has a long-term sales contract with Titan Energy Partners, L.P. ("Titan"), which is a consolidated subsidiary of ETP. The contract, which was scheduled to expire March 31, 2010, has been extended through March 31, 2015. In addition, Enterprise Products Partners 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 Enterprise Products Partners. See the summary related party transaction table at the beginning of this Note 12 for related party revenue and expense amounts recorded by Enterprise Products Partners in connection with Energy Transfer Equity.

Relationship with Duncan Energy Partners

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

At September 30, 2010, Duncan Energy Partners was owned 99.3% by its limited partners and 0.7% by its general partner, DEP GP, which is a wholly owned subsidiary of EPO. DEP GP is responsible for managing the business and operations of Duncan Energy Partners. DEP Operating Partnership L.P., a wholly owned subsidiary of Duncan Energy Partners, conducts substantially all of Duncan Energy Partners' business. At September 30, 2010, EPO owned 58.5% of Duncan Energy Partners' limited partner interests and 100% of its general partner. Due to our control of Duncan Energy Partners, its financial statements are consolidated with those of our own and our transactions with Duncan Energy Partners are eliminated in consolidation.

In June 2010, EPO entered into the Amended Acadian LLC Agreement with Duncan Energy Partners. This document includes the agreement between Duncan Energy Partners and EPO regarding funding arrangements for the Haynesville Extension project. This expansion capital project will extend our south Louisiana intrastate natural gas pipeline system, which is owned by Acadian Gas, LLC, into northwest Louisiana and the Haynesville Shale production area. Duncan Energy Partners will fund 66% of the Haynesville Extension project costs and EPO will fund the remaining 34% of such expenditures. The total expected cost of the Haynesville Extension project is approximately $1.56 billion (including capitalized interest), with Duncan Energy Partners' share currently estimated at $1.03 billion. In order to address its funding requirements under the Haynesville Extension project, Duncan Energy Partners entered into new senior unsecured credit facilities having an aggregate borrowing capacity of $1.25 billion in October 2010 (see Note 10).

In June 2010, Duncan Energy Partners entered into a $200 million revolving loan agreement with EPO. Duncan Energy Partners' borrowings under this revolving loan agreement were primarily used to fund its 66% share of the cash calls to fund this capital project. At September 30, 2010, the amount borrowed under this intercompany loan agreement was $125.0 million. This loan agreement was terminated on October 25, 2010 and amounts due thereunder were repaid using borrowings under Duncan Energy Partners' new $1.25 billion credit facilities. Since Duncan Energy Partners is a consolidated subsidiary of ours, all amounts related to the EPO loan (e.g., principal amounts borrowed/loaned, interest expense/revenue, etc.) were eliminated in the preparation of our consolidated financial stateme nts.

Note 14. Earnings Per Unit

Basic and diluted earnings per unit is computed by dividing net income or loss allocated to limited partners by the weighted-average number of Units outstanding during a period. The amount of net income allocated to limited partners is derived by subtracting, from net income or loss, our general partner's share of such net income or loss.

The following table shows the allocation of net income to our general partner for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
Net income	$ 37.0	$ 25.3	$ 161.0	$ 127.3
Multiplied by general partner ownership interest	0.01%	0.01%	0.01%	0.01%
General partner interest in net income	$ *	$ *	$ *	$ *

The following table shows the calculation of our limited partners' interest in net income and basic and diluted earnings per Unit.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
BASIC AND DILUTED EARNINGS PER UNIT				
Numerator:				
Net income before general partner interest	$ 37.0	$ 25.3	$ 161.0	$ 127.3
General partner interest in net income	*	*	*	*
Limited partners' interest in net income	$ 37.0	$ 25.3	$ 161.0	$ 127.3
Denominator:				
Weighted – average Units outstanding	139.2	139.2	139.2	137.4
Basic and diluted earnings per Unit:				
Net income before general partner interest	$ 0.27	$ 0.18	$ 1.16	$ 0.93
General partner interest in net income	*	*	*	*
Limited partners' interest in net income	$ 0.27	$ 0.18	$ 1.16	$ 0.93

* Amount is negligible

Note 15. Commitments and Contingencies

Litigation

As part of our normal business activities, we or our unconsolidated affiliates are named on occasion as defendants in litigation and legal proceedings, including those arising from regulatory and environmental matters. Although we are insured against various risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings. See Note 16 for information regarding our insurance program. We are not aware of any litigation, pending or threatened, that we believe is reasonably likely to have a significant adverse effect on our consolidated financial position, results of operations or cash flows.

We have not recorded any significant reserves for litigation matters. Our evaluation of litigation contingencies is based on the facts and circumstances of each case and predicting the outcome of these matters involves substantial uncertainties. In the event the assumptions we use to evaluate these matters change in future periods or new information becomes available, we may be required to record additional reserves. In an effort to mitigate potential adverse consequences of litigation, we may settle legal proceedings out of court.

Holdings Merger Matters. On September 9, 2010, Sanjay Israni, a purported unitholder of the Parent Company, filed a complaint in the Court of Chancery of the State of Delaware, as a putative class action on behalf of the unitholders of the Parent Company, captioned *Sanjay Israni v. EPE Holdings LLC, Enterprise GP Holdings L.P., Enterprise Products Company, Enterprise Products Partners L.P., Oscar S. Andras, Ralph S. Cunningham, Richard H. Bachmann, Randa Duncan Williams, Thurmon M. Andress, Charles E. McMahen, Edwin E. Smith and B.W. Waycaster* (the "Israni Complaint"). The Israni Complaint alleges, among other things, that Enterprise Products Partners along with the named directors and EPCO have breached fiduciary duties in connection with the proposed Holdings Merger (see Note 1) and that the Parent Company aided and abetted in these alleged breaches of fiduciary duties.

On September 24, 2010, Richard Fouke, a purported unitholder of the Parent Company, filed a complaint in the Court of Chancery of the State of Delaware as a putative class action on behalf of the unitholders of the Parent Company, captioned *Richard Fouke v. EPE Holdings LLC, Enterprise GP Holdings L.P., Enterprise Products Company, Enterprise Products Partners L.P., Enterprise Products GP, LLC, Oscar S. Andras, Ralph S. Cunningham, Richard H. Bachmann, Randa Duncan Williams, Thurmon*

M. Andress, Charles E. McMahen, Edwin E. Smith and B.W. Waycaster (the "Fouke Complaint"). The Fouke Complaint alleges, among other things, that Enterprise Products Partners, along with the named directors, EPE Holdings, EPGP and EPCO breached the implied contractual covenant of good faith and fair dealing in connection with the proposed Holdings Merger and that the Parent Company and the other defendants aided and abetted in the alleged breach.

Additionally, on September 28, 2010, Eugene Lonergan, Sr., a purported unitholder of the Parent Company, filed a complaint in the Court of Chancery of the State of Delaware, as a putative class action on behalf of the unitholders of the Parent Company, captioned *Eugene Lonergan, Sr. v. EPE Holdings LLC, Enterprise GP Holdings L.P., Oscar S. Andras, Ralph S. Cunningham, Richard H. Bachmann, Randa Duncan Williams, Thurmon M. Andress, Charles E. McMahen, Edwin E. Smith and B.W. Waycaster* (the "Lonergan Complaint"). The Lonergan Complaint alleges that the named directors and EPE Holdings breached the implied contractual covenant of good faith and fair deali ng, including failing to make adequate disclosures, in connection with the proposed Holdings Merger. On October 8, 2010, the Court of Chancery of the State of Delaware held a hearing on a motion by the plaintiff to expedite the proceedings. On October 11, 2010, the motion was denied.

Finally, on October 11, 2010, John Psomas, a purported unitholder of Enterprise Products Partners' common units, filed a complaint in the Court of Chancery of the State of Delaware, as a putative class action on behalf of Enterprise Products Partners' unitholders, captioned *John Psomas v. Enterprise Products Partners L.P., Enterprise Products GP, LLC, Michael A. Creel, W. Randall Fowler, A. James Teague, Michael J. Knesek, E. William Barnett, Charles M. Rampacek and Rex C. Ross* (the "Psomas Complaint"). The Psomas Complaint alleges that Enterprise Products Partners and its general partner breached its partnership agreement by failing to submit the Holdings Merger Agreement to a vote of Enterprise Products Partners' unitholders and that th e named directors breached their fiduciary duties of candor and full disclosure.

Each of the Israni, Fouke, Lonergan and Psomas Complaints seeks to enjoin the proposed merger transaction and, in the event the merger is consummated, the Psomas Complaint seeks a vote of Enterprise Products Partners' unitholders to ratify approval of the Holdings Merger and damages resulting from the named directors' alleged breaches of fiduciary duties. We cannot predict the outcome of these or any other lawsuits nor the amount of time and expense that will be required to resolve these or any other lawsuits filed in connection with the proposed Holdings Merger. We intend to vigorously defend against these lawsuits and any similar actions.

Parent Company Matters. In February 2008, Joel A. Gerber, a purported unitholder of the Parent Company, filed a derivative complaint on behalf of the Parent Company in the Court of Chancery of the State of Delaware. The complaint names as defendants EPE Holdings, the Board of Directors of EPE Holdings, EPCO, and Dan L. Duncan and certain of his affiliates. The Parent Company is named as a nominal defendant. The complaint alleges that the defendants, in breach of their fiduciary duties to the Parent Company and its unitholders, caused the Parent Company to purchase in May 2007 the TEPPCO GP membership interests and TEPPCO units from Mr. Duncan& #8217;s affiliates at an unfair price. The complaint also alleges that Charles E. McMahen, Edwin E. Smith and Thurmon Andress, constituting the three members of EPE Holdings' ACG Committee, cannot be considered independent because of their relationships with Mr. Duncan. The complaint seeks relief (i) awarding damages for profits allegedly obtained by the defendants as a result of the alleged wrongdoings in the complaint and (ii) awarding plaintiff costs of the action, including fees and expenses of his attorneys and experts. Management believes this lawsuit is without merit and intends to vigorously defend against it. See Note 13 for information regarding our relationship with EPCO and its affiliates.

Enterprise Products Partners' Matters. In October 2009, we received notice that the Colorado Department of Public Health and Environment, through its Air Pollution Control Division, had proposed a Compliance Order on Consent with Enterprise Gas Processing, L.L.C for alleged violations of the Colorado Air Pollution and Prevention and Control Act ("Colorado Act") with respect to operations at our Meeker natural gas processing facility. Under the Compliance Order we paid an administrative fine of approximately $0.8 million in September 2010 and are required to operate the Meeker facility in compliance with the Colorado Act.

In December 2008, the State of New Mexico filed suit in District Court in Santa Fe County, New Mexico, under the New Mexico Air Quality Control Act. The lawsuit arose out of a February 27, 2008 Notice Of Violation issued to Marathon Oil Corp. ("Marathon") as operator of the Indian Basin natural gas processing facility located in Eddy County, New Mexico. We own a 42.4% undivided interest in the assets comprising the Indian Basin facility. The State of New Mexico alleges violations of its air laws. Marathon agreed to a Consent Decree with the State of New Mexico, which was then approved by the District Court on December 21, 2009. Under the Consent Decree, Marathon paid the State of New Mexico approximately $0.6 million, agreed to $4.5 million of additional environmental proje cts in New Mexico and agreed to two projects for "corrective measures" at the facility. We are in discussions with Marathon regarding the responsibility for these payments. We believe that any potential payment we make will not have a material impact on our consolidated financial position, results of operations or cash flows.

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

Regulatory Matters

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

Contractual Obligations

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

Operating Lease Obligations. Lease and rental expense included in costs and expenses was $18.3 million and $16.2 million during the three months ended September 30, 2010 and 2009, respectively. For the nine months ended September 30, 2010 and 2009, lease and rental expense was $50.6 million and $45.0 million, respectively. There have been no material changes in our operating lease commitments since those reported in our 2009 Form 10-K.

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

During the three months ended September 30, 2009, TEPPCO determined that its river terminal business would not be able to meet certain volume commitments to a third party. As a result, TEPPCO recognized a $28.7 million charge for pipeline throughput deficiency fees it owed under the contract. The accrued deficiency charges are included in operating costs and expenses for the three and nine months ended September 30, 2009. There was no impact on net income attributable to Enterprise Products Partners, as all of this charge was absorbed by noncontrolling interests in consolidation (i.e., the former owners of TEPPCO). The balance of this accrued liability was $21.6 million at September 30, 2010.

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. These matters are in various stages of assessment and the ultimate outcome of such disputes cannot be reasonably estimated at this time. However, in our opinion, the likelihood of a material adverse outcome to us resulting from such disputes is remote. Accordingly, we have not recorded any accruals for loss contingencies related to these matters. As of September 30, 2010, such claims against us totaled approximately $19.5 million.

Centennial Guarantees

We have certain guarantee obligations in connection with our ownership interest in Centennial, which owns a refined products pipeline system that extends from the Texas Gulf Coast to central Illinois. We guaranteed one-half of Centennial's debt obligations, which obligates us to an estimated payment of $56.6 million in the event of a default by Centennial. As of September 30, 2010, we have a recorded liability of $7.9 million representing the estimated fair value of our share of the Centennial debt guaranty.

In lieu of Centennial procuring insurance to satisfy third-party claims arising from a catastrophic event, we and Centennial's other joint venture partner have entered a limited cash call agreement. We are obligated to contribute up to a maximum of $50.0 million (in proportion to our 50% ownership interest in Centennial) in the event of a catastrophic event. At September 30, 2010, we have a recorded liability of $3.4 million representing the estimated fair value of our cash call guaranty. Our cash contributions to Centennial under the agreement may be covered by our other insurance policies depending on the nature of the catastrophic event.

Note 16. Significant Risks and Uncertainties

Insurance-Related Risks

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

EPCO completed its annual insurance renewal process during the second quarter of 2010, which resulted in an increase in premiums. EPCO's deductible for onshore physical damage from windstorms increased from $25.0 million per storm to $30.0 million per storm. EPCO's onshore insurance program currently provides $141.3 million of coverage per occurrence for named windstorm events compared to $150.0 million per occurrence in the prior year. With respect to offshore assets, the deductible for windstorm damage remained at $75.0 million per storm. EPCO's insurance program for offshore Gulf of Mexico assets currently provides $124.5 million of coverage in the aggregate compared to $100.0 million of coverage in the aggregate for the prior year. In addition, at EPCO' s election, we now have access to an additional $17.5 million of coverage for either onshore or offshore windstorm-related damage claims. For non-windstorm events, EPCO's deductible for both onshore and offshore physical damage remained at $5.0 million per occurrence.

For certain of our offshore assets, producers continue to provide a specified level of physical damage insurance coverage for named windstorms. The producers associated with our Independence Hub and Marco Polo offshore Gulf of Mexico platforms continue to cover windstorm generated physical damage costs up to $300.0 million for each platform.

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

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	2009	2010	2009
Business interruption proceeds:				
Hurricane Ike	$ --	$ 19.2	$ 1.1	$ 19.2
Total business interruption proceeds	--	19.2	1.1	19.2
Property damage proceeds:				
Hurricane Ivan	--	0.7	--	0.7
Hurricane Katrina	--	3.5	--	26.7
Hurricane Rita	--	--	36.3	--
Hurricane Gustav	57.8	--	57.8	--
Hurricane Ike	21.7	--	23.6	--
Other	28.0	--	30.8	--
Total property damage proceeds	107.5	4.2	148.5	27.4
Total	$ 107.5	$ 23.4	$ 149.6	$ 46.6

We recognized gains to the extent that we received cash proceeds from business interruption insurance claims. For the three and nine months ended September 30, 2009, we recognized $19.2 million of such gains, which are a component of operating income and gross operating margin for these periods. We recognized $1.1 million of gains from business interruption insurance proceeds during the nine months ended September 30, 2010.

Of the $107.5 million of property damage insurance proceeds we received during the three months ended September 30, 2010, $64.8 million is attributable to a segment of an offshore natural gas pipeline and certain components of an offshore platform that we elected to retire (dispose of) rather than repair. The $64.8 million of cash proceeds represents the negotiated insurance value of the covered assets and is a component of proceeds from asset sales and related transactions (investing activities) as presented on our Unaudited Condensed Statements of Consolidated Cash Flows for the nine months ended September 30, 2010. Operating income for the three and nine months ended September 30, 2010 includes $56.6 million of net gains related to the disposition of these offshore assets. These net gains are a comp onent of gains from asset sales and related transactions (operating activities) as presented on our Unaudited Condensed Statements of Consolidated Cash Flows and also part of operating costs and expenses as reported on our Unaudited Condensed Consolidated Statements of Operations for the three and nine months ended September 30, 2010, as applicable.

The remainder of property damage proceeds presented in the preceding table are attributable to insurance claims where the underlying assets were repaired. We recognize gains when the insurance proceeds we receive from property damage claims exceed the related repair costs. We received cash proceeds of $42.7 million and $83.7 million related to such claims during the three and nine months ended September 30, 2010, respectively. Cash proceeds from such claims were $4.2 million and $27.4 million during the three and nine months ended September 30, 2009, respectively. Operating income and gross operating margin for the three and nine months ended September 30, 2010 include $8.2 million and $26.4 million, respectively, of gains. Operating income and gross operating margin for the three and nine months ended September 30, 2009 include $18.4 million of such gains.

At September 30, 2010, we had $7.5 million of estimated property damage insurance claims outstanding related to windstorms.

Note 17. Supplemental Cash Flow Information

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

	For the Nine Months Ended September 30,	
	2010	2009
Decrease (increase) in:		
Accounts and notes receivable – trade	$ 78.9	$ (551.2)
Accounts receivable – related party	8.5	35.2
Inventories	(520.9)	(830.1)
Prepaid and other current assets	(68.1)	(6.7)
Other assets	11.5	(14.1)
Increase (decrease) in:		
Accounts payable – trade	123.3	1.8
Accounts payable – related party	28.5	19.5
Accrued product payables	(53.9)	817.1
Accrued interest	(49.7)	(30.7)
Other current liabilities	35.5	(36.7)
Other liabilities	(5.4)	21.0
Net effect of changes in operating accounts	$ (411.8)	$ (574.9)

We incurred liabilities for construction in progress that had not been paid at September 30, 2010 and December 31, 2009, of $160.7 million and $182.6 million, respectively. Such amounts are not included under the caption “Capital expenditures” on the Unaudited Condensed Statements of Consolidated Cash Flows.

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

In September 2010, we acquired EPCO’s ownership interests in ETC in exchange for 523,306 of Enterprise Products Partners’ common units. Since we and EPCO are under common control, we recorded the net assets of ETC based on EPCO’s historical basis of $30.6 million. This transaction resulted in increases of $21.9 million of current assets, $14.4 million of property, plant and equipment, $0.1 million of other assets, $5.8 million of current liabilities, and $30.6 million of equity. See Note 13 for additional information regarding this related party transaction.

See Note 16 for information regarding cash proceeds from insurance claims.

Note 18. Supplemental Parent Company Financial Information

In order to fully understand the financial position and results of operations of the Parent Company, we are providing the condensed standalone financial information of Enterprise GP Holdings L.P. apart from that of our consolidated Partnership financial information.

The Parent Company has no operations apart from its investing activities and indirectly overseeing the management of the entities controlled by it. At September 30, 2010, the Parent Company had investments in Enterprise Products Partners, Energy Transfer Equity and their respective general partners. The Parent Company controls Enterprise Products Partners through its ownership of EPGP. The Parent Company owns noncontrolling partnership and membership interests in Energy Transfer Equity and LE GP, respectively. On September 3, 2010, the Parent Company and Enterprise Products Partners entered into an Agreement and Plan of Merger that would, if approved, result in the merger of the Parent Company with a wholly owned subsidiary of Enterprise Products Partners through a unit-for-unit exchange. 60; See Note 1 for additional information regarding this proposed merger.

The Parent Company's primary cash requirements are for general and administrative costs, debt service requirements and distributions to its partners. The principal sources of cash flow for the Parent Company are the distributions it receives from its investments in Enterprise Products Partners, Energy Transfer Equity and their respective general partners. The amount of cash distributions the Parent Company is able to pay its unitholders may fluctuate based on the level of distributions it receives from its investments. For example, if EPO is not able to satisfy certain financial covenants in accordance with its credit agreements, Enterprise Products Partners would be restricted from making quarterly cash distributions to its partners, which includes the Parent Company.

Factors such as capital contributions, debt service requirements, general and administrative costs, reserves for future distributions and other cash reserves established by the Board of EPE Holdings may affect the distributions the Parent Company makes to its unitholders. The Parent Company's credit facility contains covenants requiring it to maintain certain financial ratios. Also, the Parent Company is prohibited from making any distribution to its unitholders if such distribution would cause an event of default or otherwise violate a covenant under its credit facility.

The Parent Company's assets and liabilities are not available to satisfy the debts and other obligations of Enterprise Products Partners, Energy Transfer Equity or their respective general partners. Conversely, the assets and liabilities of these entities are not available to satisfy the debts and obligations of the Parent Company.

Enterprise Products Partners and EPGP

At September 30, 2010, the Parent Company owned 21,563,177 common units of Enterprise Products Partners and 100% of the membership interests of EPGP, which is entitled to 2% of the cash distributions paid by Enterprise Products Partners as well as the IDRs of Enterprise Products Partners.

EPGP's percentage interest in Enterprise Products Partners' quarterly cash distributions is increased through its ownership of the associated IDRs, after certain specified target levels of distribution rates are met by Enterprise Products Partners. EPGP's quarterly general partner and associated incentive distribution thresholds are as follows:

§ 2% of quarterly cash distributions up to $0.253 per unit paid by Enterprise Products Partners;

§ 15% of quarterly cash distributions from $0.253 per unit up to $0.3085 per unit paid by Enterprise Products Partners; and

§ 25% of quarterly cash distributions that exceed $0.3085 per unit paid by Enterprise Products Partners.

The following table summarizes the distributions received by EPGP from Enterprise Products Partners for the periods indicated:

	For the Nine Months Ended September 30,	
	2010	2009
From 2% general partner interest	$ 21.8	$ 15.0
From IDRs	169.5	109.9
Total	$ 191.3	$ 124.9

On October 26, 2009, the TEPPCO Merger was completed and TEPPCO and TEPPCO GP became wholly owned subsidiaries of Enterprise Products Partners. As a result, the Parent Company's ownership interests in the TEPPCO units were converted to 5,456,000 common units of Enterprise Products Partners. In addition, the Parent Company's membership interests in TEPPCO GP were exchanged for (i) 1,331,681 common units of Enterprise Products Partners and (ii) EPGP (on behalf of the Parent Company as a wholly owned subsidiary of the Parent Company) was credited in its Enterprise

Products Partners' capital account an amount to maintain its 2% general partner interest in Enterprise Products Partners. For additional information regarding the TEPPCO Merger, see "Basis of Presentation" included in Note 1.

Energy Transfer Equity and LE GP

At September 30, 2010, the Parent Company owned 38,976,090 common units of Energy Transfer Equity and approximately 40.6% of the membership interests in LE GP.

LE GP owns a 0.31% general partner interest in Energy Transfer Equity, which general partner interest has no associated IDRs in the quarterly cash distributions of Energy Transfer Equity. The business purpose of LE GP is to manage the affairs and operations of Energy Transfer Equity. LE GP has no separate business activities outside of those conducted by Energy Transfer Equity. Energy Transfer Equity is a publicly traded Delaware limited partnership. Energy Transfer Equity's cash generating assets consist of its investments in limited and general partner interests of ETP. In addition, in May 2010 Energy Transfer Equity acquired certain limited partner interests in and 100% of the general partner of RGNC. RGNC is a midstream natural gas services provider that speci alizes in the gathering and processing, compression, and transportation of natural gas and natural gas liquids.

The following table summarizes the cash distributions received by Energy Transfer Equity from ETP and RGNC for the periods indicated:

	For the Nine Months Ended September 30,	
	2010	2009
Limited partners interest	$ 169.0	$ 167.6
General partner interest	17.0	14.6
IDRs	281.8	256.5
Total distributions received	$ 467.8	$ 438.7

Condensed Parent Company Cash Flow Information

The following table presents the Parent Company's cash flow information for the periods indicated:

	For the Nine Months Ended September 30,	
	2010	2009
Operating activities:		
Net income	$ 161.0	$ 127.3
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Amortization	4.7	1.7
Equity income	(212.0)	(172.3)
Cash distributions from investees	291.5	264.6
Net effect of changes in operating accounts	11.4	(3.5)
Net cash flows provided by operating activities	256.6	217.8
Investing activities:		
Investments (1)	(33.2)	(26.1)
Cash used in investing activities	(33.2)	(26.1)
Financing activities:		
Net borrowings under debt agreements (2)	3.8	1.5
Cash distributions paid by Parent Company	(227.6)	(195.0)
Cash used in financing activities	(223.8)	(193.5)
Net change in cash and cash equivalents	(0.4)	(1.8)
Cash and cash equivalents, January 1	0.6	2.5
Cash and cash equivalents, September 30	$ 0.2	$ 0.7

(1) Primarily represents additional investments in EPGP and/or the reinvestment of cash distributions received from Enterprise Products Partners to acquire additional common units under its DRIP.

(2) Net borrowings during the nine months ended September 30, 2010 primarily represent borrowings by the Parent Company to fund its additional investments in EPGP, which in turn used such cash contributions to maintain its 2% general partner interest in Enterprise Products Partners in connection with equity offerings.

The following table details the components of cash distributions received from investees and cash distributions paid by the Parent Company for the periods indicated:

	For the Nine Months Ended September 30, 2010	For the Nine Months Ended September 30, 2009
Cash distributions from investees: (1)		
Investment in Enterprise Products Partners and EPGP:		
From common units of Enterprise Products Partners	$ 36.6	$ 22.0
From 2% general partner interest in Enterprise Products Partners	21.9	15.0
From general partner IDRs in distributions of Enterprise Products Partners	169.4	109.7
Investment in TEPPCO and TEPPCO GP: (2)		
From 4,400,000 common units of TEPPCO	--	9.6
From 2% general partner interest in TEPPCO	--	4.7
From general partner IDRs in distributions of TEPPCO	--	41.8
Investment in Energy Transfer Equity and LE GP:		
From 38,976,090 common units of Energy Transfer Equity	63.1	61.3
From member interest in LE GP	0.5	0.5
Total cash distributions received	$ 291.5	$ 264.6
Distributions by the Parent Company:		
EPCO and affiliates	$ 177.4	$ 149.9
Public	50.2	45.1
General partner interest	*	*
Total distributions by the Parent Company	$ 227.6	$ 195.0

* Amount is negligible.

(1) Represents cash distributions received during each reporting period.

(2) On October 26, 2009, the TEPPCO Merger was completed and TEPPCO and TEPPCO GP became wholly owned subsidiaries of Enterprise Products Partners.

Condensed Parent Company Balance Sheet Information

The following table presents the Parent Company's balance sheet information at the dates indicated:

	September 30, 2010	December 31, 2009
ASSETS		
Current assets	$ 2.5	$ 2.7
Investments:		
Enterprise Products Partners and EPGP	1,548.2	1,522.8
Energy Transfer Equity and LE GP	1,466.5	1,525.6
Total investments	3,014.7	3,048.4
Other assets	4.9	6.4
Total assets	$ 3,022.1	$ 3,057.5
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities	$ 38.6	$ 17.9
Long-term debt	1,085.3	1,081.5
Other long-term liabilities	10.6	4.5
Partners' equity	1,887.6	1,953.6
Total liabilities and partners' equity	$ 3,022.1	$ 3,057.5

Condensed Parent Company Income Information

The following table presents the Parent Company's income information for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2010	**2009**	**2010**	**2009**
Equity income (loss):				
Enterprise Products Partners and EPGP	$ 75.1	$ 47.0	$ 219.0	$ 137.2
TEPPCO and TEPPCO GP (1)	--	(8.8)	--	9.4
Energy Transfer Equity and LE GP	(11.9)	(0.9)	(7.0)	25.7
Total equity income	63.2	37.3	212.0	172.3
General and administrative costs	13.9	1.9	18.8	8.7
Operating income	49.3	35.4	193.2	163.6
Other expense:				
Interest expense	(12.3)	(10.1)	(32.2)	(36.3)
Net income	$ 37.0	$ 25.3	$ 161.0	$ 127.3

(1) On October 26, 2009, the TEPPCO Merger was completed and TEPPCO and TEPPCO GP became wholly owned subsidiaries of Enterprise Products Partners.

Note 19. Subsequent Event

On November 1, 2010, we acquired certain assets from Cenac Towing Co., L.L.C., Cenac Offshore, L.L.C., CTCO Marine Services, LLC, and CTCO Shipyard of Louisiana, LLC relating to their shipyard operations in Louisiana and certain membership interests in CTCO of Texas, L.L.C. and Channelview Fleeting Services, LLC relating to shipyard operations in Texas. Since we entered into the marine transportation business in 2008, we have paid the above entities for services to support this business including construction, repairs and maintenance, drydock and provisioning services. We expect these acquired assets will result in significant future cost savings for our marine fleet.

This transaction is valued at approximately $140.0 million and the consideration consists of approximately $42.3 million in cash and $97.7 million of Enterprise Products Partners' common units (represented by approximately 2.3 million common units). We will account for this business combination using the purchase method of accounting. Accordingly, such costs will be allocated to assets acquired and liabilities assumed based on fair values developed using recognized business valuation techniques. Our preliminary purchase price allocation for this transaction is as follows: $80.0 million for property, plant and equipment; $12.5 million for intangible assets (principally a non-compete agreement); and $47.5 million of goodwill. The goodwill in this transaction is attribute d to our expectation that owning these assets will result in significant future cost savings for our marine fleet.