

ENTERPRISE PRODUCTS PARTNERS L P
Form 10-Q
August 09, 2011

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

FORM 10-Q

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

For the quarterly period ended June 30, 2011

OR

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

For the transition period from ____ to ____.

Commission file number: 1-14323

ENTERPRISE PRODUCTS PARTNERS L.P.
(Exact name of Registrant as Specified in Its Charter)

Delaware
(State or Other Jurisdiction of
Incorporation or Organization)

76-0568219
(I.R.S. Employer Identification No.)

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

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

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

Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during

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the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes ☒ No ☐

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

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

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

Yes ☐ No ☒

There were 845,829,272 common units and 4,520,431 Class B units (which generally vote together with the common units) of Enterprise Products Partners L.P. outstanding at July 31, 2011. Our common units trade on the New York Stock Exchange under the ticker symbol “EPD.”

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PART I. FINANCIAL INFORMATION.

Item 1. Financial Statements.

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

	June 30, 2011	December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 109.1	\$ 65.5
Restricted cash	116.2	98.7
Accounts receivable – trade, net of allowance for doubtful accounts of \$13.8 at June 30, 2011 and \$18.4 at December 31, 2010	4,274.3	3,800.1
Accounts receivable – related parties	37.7	36.8
Inventories	994.1	1,134.0
Prepaid and other current assets	407.1	372.0
Total current assets	5,938.5	5,507.1
Property, plant and equipment, net	20,798.9	19,332.9
Investments in unconsolidated affiliates	2,085.9	2,293.1
Intangible assets, net of accumulated amortization of \$966.5 at June 30, 2011 and \$932.3 at December 31, 2010	1,756.6	1,841.7
Goodwill	2,107.1	2,107.7
Other assets	291.4	278.3
Total assets	\$32,978.4	\$31,360.8
LIABILITIES AND EQUITY		
Current liabilities:		
Current maturities of debt	\$782.3	\$282.3
Accounts payable – trade	770.3	542.0
Accounts payable – related parties	183.2	133.1
Accrued product payables	4,786.0	4,164.8
Accrued interest	271.0	252.9
Other current liabilities	566.0	505.1
Total current liabilities	7,358.8	5,880.2
Long-term debt: (see Note 9)	13,544.7	13,281.2
Deferred tax liabilities	80.9	78.0
Other long-term liabilities	218.7	220.6
Commitments and contingencies		
Equity: (see Note 10)		
Partners' equity:		
Limited partners:		
Common units (845,835,948 units outstanding at June 30, 2011 and 843,681,572 units outstanding at December 31, 2010)	11,241.9	11,288.2
Class B units (4,520,431 units outstanding at June 30, 2011 and December 31, 2010)	118.5	118.5
Accumulated other comprehensive loss	(106.2)	(32.5)

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Total partners' equity	11,254.2	11,374.2
Noncontrolling interest	521.1	526.6
Total equity	11,775.3	11,900.8
Total liabilities and equity	\$32,978.4	\$31,360.8

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
Revenues:				
Third parties	\$11,072.3	\$7,427.4	\$21,005.9	\$15,739.5
Related parties	144.2	116.0	394.3	348.4
Total revenues (see Note 11)	11,216.5	7,543.4	21,400.2	16,087.9
Costs and expenses:				
Operating costs and expenses:				
Third parties	10,140.6	6,676.1	19,252.1	14,324.0
Related parties	392.7	298.1	818.3	622.1
Total operating costs and expenses	10,533.3	6,974.2	20,070.4	14,946.1
General and administrative costs:				
Third parties	16.3	16.4	29.2	32.7
Related parties	34.1	24.1	59.1	48.1
Total general and administrative costs	50.4	40.5	88.3	80.8
Total costs and expenses (see Note 11)	10,583.7	7,014.7	20,158.7	15,026.9
Equity in income of unconsolidated affiliates	11.1	11.0	27.3	37.6
Operating income	643.9	539.7	1,268.8	1,098.6
Other income (expense):				
Interest expense	(188.3)	(179.2)	(372.1)	(337.1)
Interest income	0.3	0.5	0.6	0.7
Other, net	--	(0.1)	0.2	(0.2)
Total other expense, net	(188.0)	(178.8)	(371.3)	(336.6)
Income before provision for income taxes	455.9	360.9	897.5	762.0
Provision for income taxes	(7.4)	(6.5)	(14.5)	(15.2)
Net income	448.5	354.4	883.0	746.8
Net income attributable to noncontrolling interest (see Note 10)	(14.8)	(300.3)	(28.6)	(622.8)
Net income attributable to partners	\$433.7	\$54.1	\$854.4	\$124.0
Allocation of net income attributable to partners:				
Limited partners	\$433.7	\$54.1	\$854.4	\$124.0
General partner	\$--	\$*	\$--	\$*
Earnings per unit (see Note 13)				
Basic earnings per unit	\$0.53	\$0.26	\$1.05	\$0.59
Diluted earnings per unit	\$0.51	\$0.26	\$1.00	\$0.59

See Notes to Unaudited Condensed Consolidated Financial Statements.

* Amount is negligible.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
Net income	\$448.5	\$354.4	\$883.0	\$746.8
Other comprehensive income (loss):				
Cash flow hedges:				
Commodity derivative instrument gains (losses) during period	(21.7)	92.0	(173.1)	33.1
Reclassification adjustment for (gains) losses included in net income related to commodity derivative instruments	74.8	(1.5)	143.7	15.0
Interest rate derivative instrument losses during period	(60.1)	(79.3)	(46.0)	(86.8)
Reclassification adjustment for losses included in net income related to interest rate derivative instruments	1.5	7.2	3.0	13.3
Foreign currency derivative losses during period	--	(0.1)	--	(0.2)
Reclassification adjustment for gains included in net income related to foreign currency derivative instruments	--	--	--	(0.3)
Total cash flow hedges	(5.5)	18.3	(72.4)	(25.9)
Foreign currency translation adjustment	--	(0.8)	--	(0.2)
Change in funded status of pension and postretirement plans, net of tax	(0.9)	--	(0.6)	(0.9)
Proportionate share of other comprehensive income (loss) of unconsolidated affiliate	0.3	(1.4)	(0.7)	(0.4)
Total other comprehensive income (loss)	(6.1)	16.1	(73.7)	(27.4)
Comprehensive income	442.4	370.5	809.3	719.4
Comprehensive income attributable to noncontrolling interest	(14.8)	(321.3)	(28.6)	(600.8)
Comprehensive income attributable to partners	\$427.6	\$49.2	\$780.7	\$118.6

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

	For the Six Months Ended June 30,	
	2011	2010
Operating activities:		
Net income	\$883.0	\$746.8
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	484.8	453.5
Non-cash asset impairment charges	--	1.5
Equity in income of unconsolidated affiliates	(27.3)	(37.6)
Distributions received from unconsolidated affiliates	84.8	101.3
Operating lease expenses paid by EPCO	0.3	0.3
Gains from asset sales and related transactions	(23.6)	(5.7)
Deferred income tax expense	2.3	1.3
Changes in fair market value of derivative instruments	(10.7)	(4.9)
Effect of pension settlement recognition	(0.5)	(0.2)
Net effect of changes in operating accounts (see Note 16)	361.4	(335.9)
Net cash flows provided by operating activities	1,754.5	920.4
Investing activities:		
Capital expenditures	(1,716.2)	(746.8)
Contributions in aid of construction costs	6.4	8.7
Decrease (increase) in restricted cash	(17.5)	52.6
Cash used for business combinations	--	(1,220.2)
Investments in unconsolidated affiliates	(11.8)	(10.2)
Proceeds from asset sales and related transactions	250.5	24.1
Other investing activities	(3.6)	--
Cash used in investing activities	(1,492.2)	(1,891.8)
Financing activities:		
Borrowings under debt agreements	3,791.1	3,593.9
Repayments of debt	(3,033.5)	(2,256.7)
Debt issuance costs	(12.8)	(14.8)
Cash distributions paid to partners	(966.5)	(149.6)
Cash distributions paid to noncontrolling interest	(34.8)	(720.5)
Cash contributions from noncontrolling interest	2.6	961.9
Net cash proceeds from issuance of common units	45.1	--
Acquisition of treasury units	(9.6)	(3.0)
Other financing activities	(0.3)	1.3
Cash provided by (used in) financing activities	(218.7)	1,412.5
Effect of exchange rate changes on cash	--	0.1
Net change in cash and cash equivalents	43.6	441.1
Cash and cash equivalents, January 1	65.5	55.3
Cash and cash equivalents, June 30	\$109.1	\$496.5

See Notes to Unaudited Condensed Consolidated Financial Statements.

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ENTERPRISE PRODUCTS PARTNERS L.P.
 UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED EQUITY
 (See Note 10 for Unit History, Accumulated Other Comprehensive Loss and Noncontrolling Interest)
 (Dollars in millions)

	Partners' Equity			
		Accumulated		
	Limited	Other	Noncontrolling	Total
	Partners	Comprehensive Loss	Interest	
Balance, December 31, 2010	\$11,406.7	\$ (32.5)	\$ 526.6	\$11,900.8
Net income	854.4	--	28.6	883.0
Operating lease expenses paid by EPCO	0.3	--	--	0.3
Cash distributions paid to partners	(966.5)	--	--	(966.5)
Cash distributions paid to noncontrolling interest	--	--	(34.8)	(34.8)
Cash contributions from noncontrolling interest	--	--	2.6	2.6
Net cash proceeds from issuance of common units	45.1	--	--	45.1
Acquisition of treasury units	(9.6)	--	--	(9.6)
Amortization of equity awards	25.2	--	0.1	25.3
Change in value of cash flow hedges	--	(72.4)	--	(72.4)
Proportionate share of other comprehensive loss of unconsolidated affiliate	--	(0.7)	--	(0.7)
Other	4.8	(0.6)	(2.0)	2.2
Balance, June 30, 2011	\$11,360.4	\$ (106.2)	\$ 521.1	\$11,775.3

	Partners' Equity			
		Accumulated		
	Limited	Other	Noncontrolling	Total
	Partners	General Partner	Comprehensive Loss	Interest
Balance, December 31, 2009	\$1,972.4	\$*	\$ (33.3)	\$ 8,534.0
Net income	124.0	*	--	622.8
Operating lease expenses paid by EPCO	--	--	--	0.3
Cash distributions paid to partners	(149.6)	*	--	--
Cash distributions paid to noncontrolling interest	--	--	--	(720.5)
Cash contributions from noncontrolling interest	--	--	--	961.9
Acquisition of treasury units	--	--	--	(3.0)
Amortization of equity awards	1.1	--	--	18.2
Change in value of cash flow hedges	--	--	(5.0)	(20.9)
Proportionate share of other comprehensive loss of unconsolidated affiliate	--	--	(0.4)	--
Other	--	--	--	(1.1)
Balance, June 30, 2010	\$1,947.9	\$*	\$ (38.7)	\$ 9,391.7

See Notes to Unaudited Condensed Consolidated Financial Statements.

* Amount is negligible.

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

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

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

Unless the context requires otherwise, references to “we,” “us,” “our,” “Enterprise” or “Enterprise Products Partners” are intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries. References to “EPO” mean Enterprise Products Operating LLC, which is a wholly owned subsidiary of Enterprise, and its consolidated subsidiaries, through which Enterprise conducts substantially all of its business. Enterprise is managed by its general partner, Enterprise Products Holdings LLC (“Enterprise GP”), which is a wholly owned subsidiary of Dan Duncan LLC, a Delaware limited liability company.

On September 3, 2010, Enterprise GP Holdings L.P. (“Holdings”), Enterprise, Enterprise GP, Enterprise Products GP, LLC (“EPGP,” the former general partner of Enterprise) and Enterprise ETE LLC (“Holdings MergerCo,” a Delaware limited liability company and a wholly owned subsidiary of Enterprise) entered into a merger agreement (the “Holdings Merger Agreement”). On November 22, 2010, the Holdings Merger Agreement was approved by the unitholders of Holdings and the merger of Holdings with and into Holdings MergerCo and related transactions were completed, with Holdings MergerCo surviving such merger (collectively, we refer to these transactions as the “Holdings Merger”). Enterprise’s membership interests in Holdings MergerCo were subsequently contributed to EPO. For additional information regarding the Holdings Merger, see Note 1.

The membership interests of Dan Duncan LLC are owned of record by a voting trust, the current trustees (“DD LLC Trustees”) of which are: (i) Randa Duncan Williams, who is also a director of Enterprise GP; (ii) Dr. Ralph S. Cunningham, who is also a director and the Chairman of Enterprise GP and one of three managers of Dan Duncan LLC; and (iii) Richard H. Bachmann, who is also a director of Enterprise GP and one of three managers of Dan Duncan LLC.

References to “EPCO” mean Enterprise Products Company and its privately held affiliates. A majority of the outstanding voting capital stock of EPCO is owned of record by a voting trust, the current trustees (“EPCO Trustees”) of which 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 and Chief Executive Officer (“CEO”) of EPCO. Ms. Williams, Dr. Cunningham and Mr. Bachmann are also currently directors of EPCO.

References to “Duncan Energy Partners” mean Duncan Energy Partners L.P. (NYSE: DEP), which is a consolidated subsidiary of EPO. References to “DEP GP” mean DEP Holdings, LLC, which is the general partner of Duncan Energy Partners and a wholly owned subsidiary of EPO. On April 28, 2011, we, our general partner, and two of our subsidiaries entered into a definitive merger agreement with Duncan Energy Partners and DEP GP. See Note 1 for information regarding the proposed merger of Duncan Energy Partners with a subsidiary of Enterprise.

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

References to “Energy Transfer Equity” mean the business and operations of Energy Transfer Equity, L.P. (NYSE: ETE) and its consolidated subsidiaries, which include Energy Transfer Partners, L.P. (“ETP”) and Regency Energy

Partners LP (“RGNC”). The general partner of Energy Transfer Equity is LE GP, LLC (“LE GP”). We own noncontrolling interests in Energy Transfer Equity, which we account for using the equity method of accounting.

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

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

Duncan Energy Partners and Energy Transfer Equity electronically file certain documents with the U.S. Securities and Exchange Commission (“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 Operations, Organization and Basis of Presentation

We are a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol EPD. We were formed in April 1998 to own and operate certain natural gas liquids (“NGLs”) related businesses of EPCO. We are a leading North American provider of midstream energy services to producers and consumers of natural gas, NGLs, crude oil, refined products and certain petrochemicals. Our midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States, Canada and the Gulf of Mexico with domestic consumers and international markets. Our assets include approximately 50,200 miles of onshore and offshore pipelines; 190 million barrels (“MMBbls”) of storage capacity for NGLs, refined products and crude oil; and 27 billion cubic feet (“Bcf”) of natural gas storage capacity.

Our midstream energy operations include: natural gas gathering, treating, processing, transportation and storage; NGL transportation, fractionation, storage, and import and export terminaling; crude oil and refined products transportation, storage, and terminaling; offshore production platforms; petrochemical transportation and services; and a marine transportation business that operates primarily on the United States inland and Intracoastal Waterway systems and in the Gulf of Mexico. We have 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 reflect the manner in which these businesses are managed and reviewed by the CEO of our general partner. See Note 11 for additional information regarding our business segments.

We are 100% owned by our limited partners from an economic perspective. We are managed and controlled by Enterprise GP, which has a non-economic general partner interest in us. We, Enterprise GP, EPCO and Dan Duncan LLC are affiliates and under the collective common control of the DD LLC and EPCO Trustees. We have no employees. All of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to an administrative services agreement (the “ASA”) or by other service providers. See Note 12 for information regarding the ASA and other related party matters.

Agreement and Plan of Merger with Duncan Energy Partners

On April 28, 2011, we entered into an Agreement and Plan of Merger (the “Duncan Merger Agreement”), by and among Enterprise, Enterprise GP, EPD MergerCo LLC (“Duncan MergerCo,” a Delaware limited liability company and a wholly owned subsidiary of Enterprise), Duncan Energy Partners and DEP GP. At the effective time of the merger, Duncan MergerCo will merge with and into Duncan Energy Partners, pursuant to the Duncan Merger Agreement, with Duncan Energy Partners surviving the merger as a wholly owned subsidiary of Enterprise (the “Duncan Merger”), and all of the outstanding Duncan Energy Partners common units at the effective time of the merger will be cancelled and converted into the right to receive common units representing limited partner interests in Enterprise based on an

exchange rate of 1.01 Enterprise common units for each Duncan Energy Partners common unit.

On September 7, 2011, Duncan Energy Partners will host a special meeting of its unitholders to consider and vote upon approval of the Duncan Merger Agreement and the Duncan Merger. The Duncan

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

Merger Agreement and the Duncan Merger must be approved by the affirmative vote or consent of holders of (i) a majority of the outstanding common units of Duncan Energy Partners and (ii) a majority of the Duncan Energy Partners common units owned by the Duncan Unaffiliated Unitholders (as defined in the Duncan Merger Agreement) that actually vote for or against such approval. In connection with the Duncan Merger Agreement, we, Duncan Energy Partners and Enterprise GTM Holdings L.P., a Delaware limited partnership and a wholly owned subsidiary of Enterprise (“Enterprise GTM”), entered into a Voting Agreement, dated as of April 28, 2011 (the “Voting Agreement”), pursuant to which Enterprise GTM and Enterprise agreed to vote any of the Duncan Energy Partners common units owned by them or their subsidiaries in favor of the adoption of the Duncan Merger Agreement and the Duncan Merger at any meeting of the Duncan Energy Partners unitholders, including the 33,783,587 Duncan Energy Partners common units currently directly owned by Enterprise GTM (representing approximately 58.5% of the outstanding common units of Duncan Energy Partners). The Voting Agreement will terminate upon the termination of the Duncan Merger Agreement.

The Duncan Merger Agreement contains customary representations, warranties and covenants by each of the parties. Completion of the Duncan Merger is conditioned upon, among other things: (i) requisite Duncan Energy Partners unitholder approval of the Duncan Merger Agreement and the Duncan Merger; (ii) applicable regulatory approvals; (iii) the absence of certain legal injunctions or impediments prohibiting the transactions; (iv) the effectiveness of a registration statement on Form S-4 with respect to the issuance by Enterprise of the Enterprise common units in connection with the Duncan Merger (the Form S-4 was declared effective by the SEC on August 1, 2011); (v) the receipt of certain tax opinions; and (vi) approval for the listing of the Enterprise common units issued in connection with the Duncan Merger on the NYSE.

Basis of Presentation

Holdings Merger. On November 22, 2010, the Holdings Merger Agreement was approved by the unitholders of Holdings and the merger of Holdings with Holdings MergerCo and related transactions were completed, with Holdings MergerCo surviving such merger. At the effective time of the Holdings Merger, Enterprise GP succeeded as Enterprise’s general partner, and each issued and outstanding unit representing limited partner interests in Holdings was cancelled and converted into the right to receive Enterprise common units based on an exchange ratio of 1.5 Enterprise common units for each Holdings unit. Enterprise issued an aggregate of 208,813,454 of its common units (net of 23 fractional common units cashed out) as consideration in the Holdings Merger and, immediately after the merger, cancelled 21,563,177 of its common units previously owned by Holdings.

In connection with the Holdings Merger, Enterprise’s partnership agreement was amended and restated to provide for the cancellation of its general partner’s 2% economic general partner interest and incentive distribution rights in Enterprise. In addition, a privately held affiliate of EPCO agreed to temporarily waive the regular quarterly cash distributions it would otherwise receive from Enterprise with respect to a certain number of Enterprise’s common units (the “Designated Units”) over a five-year period after the merger closing date. The number of Designated Units to which the temporary distribution waiver applies 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.

Prior to the Holdings Merger, Enterprise was a consolidated subsidiary of Holdings, which was Enterprise’s parent. Upon completion of the Holdings Merger, Holdings merged with and into a wholly owned subsidiary of Enterprise. The Holdings Merger resulted in Holdings being considered the surviving consolidated entity for accounting purposes, while Enterprise is the surviving consolidated entity for legal and reporting purposes. For accounting purposes, Holdings is deemed the acquirer of the noncontrolling interests in Enterprise that were

previously recognized in Holdings' consolidated financial statements (i.e., the acquisition of Enterprise's limited partner interests that were owned by parties other than Holdings).

As a result of the Holdings Merger, Enterprise's consolidated financial and operating results prior to November 22, 2010 have been presented as if it were Holdings from an accounting perspective (i.e., the

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financial statements of Holdings become the historical financial statements of Enterprise). The primary differences between Holdings' and Enterprise's consolidated results of operations were: (i) general and administrative costs incurred by Holdings and EPGP (our former general partner); (ii) equity in income of Holdings' noncontrolling ownership interests in Energy Transfer Equity; and (iii) interest expense associated with Holdings' debt. In addition, for periods prior to November 22, 2010, the net assets, income, cash distributions and contributions and other amounts attributable to Enterprise's limited partner interests that were owned by third parties and related parties other than Holdings are presented as a component of noncontrolling interest. See Note 10 for additional information regarding noncontrolling interests.

The historical limited partner units outstanding and earnings per unit amounts presented in our financial statements have been retroactively presented in connection with the 1.5 to one unit-for-unit exchange that occurred under the Holdings Merger. See Note 13 for additional information regarding earnings per unit.

Consolidation of Duncan Energy Partners. For financial reporting purposes, we consolidate the financial statements of Duncan Energy Partners with those of our own and reflect its operations in our business segments. We control Duncan Energy Partners through our ownership of its general partner. Public ownership of Duncan Energy Partners' net assets and earnings are presented as a component of noncontrolling interest in our consolidated financial statements. The borrowings of Duncan Energy Partners are presented as part of our consolidated debt. However, neither Enterprise Products Partners nor EPO have any obligation for the payment of interest or repayment of borrowings incurred by Duncan Energy Partners. Since we consolidate Duncan Energy Partners for financial reporting purposes, the proposed Duncan Merger would not change the basis of presentation of our historical financial statements.

Note 2. General Accounting Matters

Our results of operations for the three and six months ended June 30, 2011 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 and 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 SEC. These Unaudited Condensed Consolidated Financial Statements and the Notes thereto should be read in conjunction with the Audited Consolidated Financial Statements and Notes thereto included in our annual report on Form 10-K for the year ended December 31, 2010 (the "2010 Form 10-K") filed on March 1, 2011.

Allowance for Doubtful Accounts

Our allowance for doubtful accounts is determined based on specific identification and estimates of future uncollectible accounts. Our procedure for determining the allowance for doubtful accounts is based on: (i) historical experience with customers, (ii) the perceived financial stability of customers based on our research and (iii) the levels of credit we grant to customers. In addition, we may increase the allowance account in response to the specific identification of customers involved in bankruptcy proceedings and similar financial difficulties. On a routine basis, we review estimates associated with the allowance for doubtful accounts to ensure that we have recorded sufficient reserves to cover potential losses. Our allowance also includes estimates for uncollectible natural gas imbalances based on specific identification of accounts.

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The following table presents the activity of our allowance for doubtful accounts for the periods presented:

	For the Six Months Ended June 30,	
	2011	2010
Balance at beginning of period	\$18.4	\$16.8
Charged to costs and expenses	0.6	0.7
Deductions (1)	(5.2)	--
Balance at end of period	\$13.8	\$17.5

(1) Primarily due to our reassessment of the allowance for doubtful accounts as a result of improved credit ratings of a significant customer, which reduced our exposure to potential uncollectibility.

Contingencies

Certain conditions may exist as of the date our financial statements are issued, which may result in a loss to us but which will only be resolved when one or more future events occur or fail to occur. Management has regular quarterly litigation reviews, including updates from legal counsel, to assess the need for accounting recognition or disclosure of these contingencies, and such assessment inherently involves an exercise in judgment. In assessing loss contingencies related to legal proceedings that are pending against us or unasserted claims that may result in proceedings, our management and legal counsel evaluate the perceived merits of any legal proceedings or unasserted claims as well as the perceived merits of the amount of relief sought or expected to be sought therein.

We accrue an undiscounted liability for those contingencies where the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. We do not record a contingent liability when the likelihood of loss is probable but the amount cannot be reasonably estimated or when it is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is reasonably possible and the impact would be material, we disclose the nature of the contingency and, where feasible, an estimate of the possible loss or range of loss. Loss contingencies considered remote are generally not disclosed unless they involve guarantees, in which case the guarantees would be disclosed. See Note 14 for additional information regarding our contingencies.

Derivative Instruments

We use derivative instruments such as swaps, forwards and other contracts to manage price risks associated with inventories, firm commitments, interest rates and certain anticipated transactions. To qualify for hedge accounting, the item to be hedged must expose us to risk and the related derivative instrument must reduce that exposure and meet specific documentation requirements. We formally designate a derivative instrument as a hedge and document and assess the effectiveness of the hedge at inception and thereafter on a quarterly basis.

We apply the normal purchases/normal sales exception for certain of our derivative instruments, which precludes the recognition of changes in mark-to-market values for these items on our balance sheet or income statement. Revenues and costs for these transactions are recognized when volumes are physically delivered or received.

See Note 4 for additional information regarding our derivative instruments and related hedging activities.

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Earnings Per Unit

Earnings per unit is based on the amount of net income attributable to limited partners and the weighted-average number of units outstanding during the period. See Note 1 for information regarding the retroactive presentation of earnings per unit amounts for the three and six months ended June 30, 2010 in connection with the Holdings Merger.

Estimates

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

The carrying amounts of cash and cash equivalents (including restricted cash), accounts receivable and accounts payable approximate their fair value. See Note 4 for fair value information associated with our derivative instruments.

The estimated fair value of our fixed-rate debt obligations was approximately \$14.09 billion and \$12.91 billion at June 30, 2011 and December 31, 2010, respectively. These values 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.

We do not have any long-term investments in debt or equity securities carried at fair value. See Note 7 for summarized financial information of our investments accounted for using the equity method.

Liquids Exchange Contracts

Our liquids exchange balances were net payables of \$212.4 million and \$144.1 million at June 30, 2011 and December 31, 2010, respectively. The most significant liquids exchange transactions recorded on our consolidated balance sheet relate to those involving petrochemical volumes. Petrochemical transactions accounted for approximately 62% and 85% of our liquids exchange transactions recorded at June 30, 2011 and December 31, 2010, respectively. Under these agreements, we physically receive volumes of propane/propylene mix (an unprocessed stream), including the risk of loss and legal title to such volumes, from the exchange counterparty. In turn, we deliver segregated polymer grade propylene and propane (processed streams) back to the customer and charge them a processing or similar fee. The intent of these exchange transactions is the earning of fee revenue for processing and transporting the propane/propylene mix using our assets. This arrangement satisfies the commercial, logistical and timing needs of our customer and allows us to operate our plants more effectively.

To the extent that the volumes we receive under such exchange agreements exceed those we deliver under the agreements (measured as of the end of each reporting period), we recognize a net exchange payable position with the counterparties. With respect to the petrochemical transactions discussed above, we are typically in a net exchange payable position with our counterparties. In those limited situations where the volumes we deliver exceed those we receive (measured as of the end of each reporting period), we recognize a net exchange receivable position with the counterparties. From an income statement perspective, the only revenue recognized from such exchange agreements

is fee revenue. From a balance sheet perspective, net exchange payables arising from these transactions are valued at market-based prices. To the extent that we recognize net exchange receivables arising from liquids exchange transactions, such balances are valued at average cost.

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Volumetric receivables and payables arising from exchange transactions are typically balanced with movements of products rather than with cash. When payment or receipt of monetary consideration is required for product differentials and service costs with a counterparty, such items are recognized in our consolidated financial statements on a net basis as either operating revenues or expense, as appropriate.

Recent Accounting Developments

Fair Value Measurements. In May 2011, the Financial Accounting Standards Board (or “FASB”) issued an accounting standard update that amended previous fair value measurement and disclosure guidance. These amendments generally involve clarifications on how to measure and disclose fair value amounts recognized in the financial statements. They also expand the disclosure requirements, particularly for Level 3 fair value measurements, to include a description of the valuation processes used and an analysis of the sensitivity of the fair value measurements to changes in unobservable inputs and the interrelationships between those unobservable inputs, if any. We will adopt this guidance on January 1, 2012 and apply its requirements prospectively at that time. We do not believe the adoption of this guidance will have a material impact on our consolidated financial statements.

Presentation of Other Comprehensive Income. In June 2011, the FASB issued an accounting standard update that revised the financial statement presentation of other comprehensive income (“OCI”). The amended guidance requires entities to present components of comprehensive income in either (i) a single continuous statement of comprehensive income or (ii) two separate but consecutive statements (i.e., a statement of income and a statement of comprehensive income, which is our current format). Although the amended guidance does not change the items that must be reported in OCI, reclassification adjustments for each component of OCI will have to be displayed in both net income and OCI. We will adopt this guidance on January 1, 2012 and apply its presentation requirements retrospectively at that time. We do not believe the adoption of this guidance will have a material impact on our consolidated financial statements.

Restricted Cash

Restricted cash represents amounts held in connection with our commodity derivative instruments portfolio and related physical natural gas, crude oil and NGL purchases. Additional cash may be restricted to maintain this portfolio as commodity prices fluctuate or deposit requirements change. At June 30, 2011 and December 31, 2010, our restricted cash amounts were \$116.2 million and \$98.7 million, respectively. See Note 4 for information regarding 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 presented:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
Restricted unit awards	\$12.1	\$7.9	\$23.5	\$13.7
Unit option awards	0.8	0.7	1.7	1.4
Other (1)	0.3	2.5	(0.2)	4.7
Total compensation expense	\$13.2	\$11.1	\$25.0	\$19.8

(1) Primarily consists of unit appreciation rights (“UARs”), phantom units and similar awards. Also, the amounts presented for 2010 consist of awards related to limited partnership interests in the Employee Partnerships.

The fair value of equity-classified awards (e.g., restricted common unit and unit option awards) is amortized to earnings over the requisite service or vesting period. Compensation expense for liability-classified awards (e.g., UARs and phantom units) is recognized over the requisite service or vesting period

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based on the fair value of the award remeasured at each reporting period. Liability-classified awards are settled in cash upon vesting.

At June 30, 2011, EPCO's significant long-term incentive plans applicable to us were the Enterprise Products 1998 Long-Term Incentive Plan ("1998 Plan"), the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan ("2008 Plan") and the 2010 Duncan Energy Partners L.P. Long-Term Incentive Plan ("2010 Plan"). In addition, there were unvested awards outstanding under an inactive plan, the Enterprise Products 2006 TPP Long-Term Incentive Plan ("2006 Plan").

The 1998 Plan provides for awards of our common units and other rights to our non-employee directors and to employees of EPCO and its affiliates providing services to us. Awards under the 1998 Plan may be granted in the form of unit options, restricted common units, phantom units and distribution equivalent rights ("DERs"). Up to 7,000,000 of our common units may be issued as awards under the 1998 Plan. After giving effect to awards granted under the plan through June 30, 2011, a total of 1,475,190 additional common units could be issued.

The 2008 Plan provides for awards of our common units and other rights to our non-employee directors and to consultants and employees of EPCO and its affiliates providing services to us. Awards under the 2008 Plan may be granted in the form of unit options, restricted common units, phantom units, UARs and DERs. Up to 10,000,000 of our common units may be issued as awards under the 2008 Plan. After giving effect to awards granted under the plan through June 30, 2011, a total of 4,706,877 additional common units could be issued.

The 2010 Plan provides for awards to employees, directors or consultants providing services to Duncan Energy Partners. Awards under the 2010 Plan may be granted in the form of options to purchase Duncan Energy Partners' common units, restricted common units, UARs, phantom units and DERs. Up to 500,000 of Duncan Energy Partners' common units may be issued as awards under the 2010 Plan. After giving effect to awards granted under the plan through June 30, 2011, a total of 489,986 additional common units could be issued. The Duncan Merger Agreement contains restrictions on the issuance of additional awards under the 2010 Plan. See Note 1 for information regarding the proposed merger of Duncan Energy Partners with a subsidiary of Enterprise.

Restricted Common Unit Awards

Restricted common 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 common unit awards may be denominated in our common units or those of Duncan Energy Partners depending on the issuer of the award. Restricted common unit awards issued prior to 2010 generally cliff vest four years from the date of grant. Beginning with awards issued in 2010, restricted common 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 "restricted common unit" represents a time-vested unit. Such awards are non-vested until the required service period expires. Restricted common units are included in the number of common units presented on our Unaudited Condensed Consolidated Balance Sheets.

The fair value of a restricted common 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.

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The following table presents information regarding restricted common unit awards for the period presented:

	Number of Units	Weighted- Average Grant Date Fair Value per Unit (1)
Enterprise restricted common unit awards:		
Restricted common units at December 31, 2010	3,561,614	\$29.78
Granted (2)	1,359,230	\$43.68
Vested	(828,545)	\$31.57
Forfeited	(75,857)	\$32.67
Restricted common units at June 30, 2011	4,016,442	\$34.06
Duncan Energy Partners restricted common unit awards:		
Restricted common units at December 31, 2010	--	\$--
Granted (3)	3,666	\$32.56
Vested (3)	(3,666)	\$32.56
Restricted common units at June 30, 2011	--	\$--

(1) Determined by dividing the aggregate grant date fair value of awards (before an allowance for forfeitures) by the number of awards issued.

(2) The aggregate grant date fair value of restricted common unit awards issued in 2011 was \$59.4 million based on a grant date market price of our common units ranging from \$40.54 to \$43.70 per unit. An estimated annual forfeiture rate of 4.6% was applied to these awards.

(3) The aggregate grant date fair value of restricted common unit awards issued in 2011 was \$0.1 million based on a grant date market price of Duncan Energy Partners' common units of \$32.56 per unit. These awards vested upon issuance.

Typically, each recipient is also entitled to nonforfeitable cash distributions equal to the product of the number of restricted common units outstanding for the participant and the cash distribution per unit paid by the respective issuer. Since these restricted common units are participating securities, such distributions are included in cash distributions paid to partners (post-Holdings Merger) and cash distributions paid to noncontrolling interest (pre-Holdings Merger) as presented on our Unaudited Condensed Statements of Consolidated Cash Flows.

The following table presents cash distributions paid with respect to our restricted common units and the total intrinsic value of restricted common units that vested during the periods presented:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
Cash distributions paid to restricted common unit holders	\$2.7	\$2.3	\$4.8	\$3.8
Total intrinsic value of restricted common unit awards vesting during period	20.5	10.3	35.2	11.4

For the EPCO group of companies, the unrecognized compensation cost associated with restricted common unit awards was an aggregate \$73.5 million at June 30, 2011, of which our allocated share of the cost is currently estimated to be \$69.4 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.0 years.

Unit Option Awards

EPCO's long-term incentive plans provide for the issuance of non-qualified incentive options. These unit option awards may be denominated in our common units or those of Duncan Energy Partners depending on the issuer of the award. When issued, the exercise price of each unit option award may be no less than the market price of the underlying security on the date of grant. In general, these unit option awards have a vesting period of four years from the date of grant and expire five years after the date of grant.

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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. In general, our assumptions regarding the expected life of the options represent the period of time that the options are expected to be outstanding based on an analysis of our historical option activity. Our selection of risk-free interest rates is based on published yields for U.S. government securities with comparable terms. The unit price volatility and expected distribution yield assumptions are based on several factors, including an analysis of the underlying security's historical market price and its distribution yield over a period of time equal to the expected life of the option, respectively. Compensation expense recorded in connection with unit options is based on the grant date fair value of such awards, net of an allowance for estimated forfeitures, over the requisite service or vesting period.

The following table presents unit option activity for the period presented. As of June 30, 2011, only Enterprise 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, 2010	3,753,420	\$ 28.08	3.6	\$--
Unit options at June 30, 2011	3,753,420	\$ 28.08	3.1	\$7.3
Options exercisable at June 30, 2011 (2)	--		--	\$--

(1) Aggregate intrinsic value reflects fully vested unit options at the date indicated. There were no vested unit options outstanding at December 31, 2010.

(2) We were committed to issue 3,753,420 of our common units at June 30, 2011 if all outstanding options awarded were exercised. Option awards outstanding at June 30, 2011 include 612,280 awards that vested during the first six months of 2011. Of the remaining outstanding option awards at June 30, 2011, 100,000, 736,000, 1,520,140 and 785,000 will vest in 2011, 2012, 2013, and 2014, respectively. These unit option awards become exercisable in the calendar year following the year in which they vest.

In order to fund its unit option-related obligations, EPCO may purchase common units at fair value either in the open market or directly from us. 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 units issued to the employee.

The following table presents supplemental information regarding our unit options during the periods presented:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
Total intrinsic value of unit option awards exercised during period	\$--	\$1.3	\$--	\$2.2
Cash received from EPCO in connection with the exercise of unit option awards	--	1.0	--	1.6
Unit option-related reimbursements to EPCO	--	1.3	--	2.2

For the EPCO group of companies, the unrecognized compensation cost associated with unit option awards was an aggregate \$5.0 million at June 30, 2011, of which our allocated share of the cost is currently estimated to be \$4.5 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 1.9 years.

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Other

Unit appreciation rights. UARs entitle the recipient to receive a cash payment on the vesting date of the award equal to the excess, if any, of the then current fair market value of the underlying security over the grant date fair value of the award. UARs are accounted for as liability awards. All of the UARs outstanding at June 30, 2011 are denominated in Enterprise common units.

The following tables present information regarding UARs for the period presented:

UARs at December 31, 2010	170,104	
Vested	(10,939)	
Settled or forfeited	(45,000)	
UARs at June 30, 2011	114,165	
	June 30, 2011	December 31, 2010
Accrued liability for UARs	\$0.4	\$1.0

At June 30, 2011, 114,165 UARs that had been granted under the 2006 Plan to certain employees of EPCO who work on our behalf were outstanding. These awards are subject to five-year cliff vesting requirements and are expected to settle in 2012. The grant date fair value with respect to these UARs is based on a unit price of \$37.00 for our common units. If the employee resigns prior to vesting, the UARs are forfeited. Equity-based compensation expense associated with UARs was minimal for the three months ended June 30, 2011 and \$0.2 million for the three months ended June 30, 2010. For the six months ended June 30, 2011 and 2010, equity-based compensation expense associated with UARs was a credit of \$0.6 million and an expense of \$0.3 million, respectively.

Limited partnership interests. EPCO granted its key employees who perform services on behalf of us, EPCO and other affiliated companies, limited partnership interests in the Employee Partnerships, which were privately held affiliates of EPCO. These partnerships were liquidated in August 2010. Prior to liquidation, the limited partnership interests 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 common units or Holdings' units or a combination of both. Equity-based compensation expense for the three and six months ended June 30, 2010 includes \$1.9 million and \$3.8 million, respectively, of expense associated with these limited partnership interests.

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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 and commodity prices. In order to manage risks associated with certain anticipated future transactions, we use derivative instruments. Derivatives are financial instruments whose fair value is determined by changes in a specified benchmark such as interest rates or commodity prices. 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. Derivative instruments typically 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 our 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 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.

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

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

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

Interest Rate Derivative Instruments

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

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The following table summarizes our interest rate derivative instruments outstanding at June 30, 2011:

Hedged Transaction	Number and Type of Derivative(s) Employed	Notional Amount	Period of Hedge	Rate Swap	Accounting Treatment
Senior Notes C	1 fixed-to-floating swap	\$100.0	1/04 to 2/13	6.4% to 2.3%	Fair value hedge
Senior Notes G	3 fixed-to-floating swaps	\$300.0	10/04 to 10/14	5.6% to 1.4%	Fair value hedge
Senior Notes P	7 fixed-to-floating swaps	\$400.0	6/09 to 8/12	4.6% to 2.7%	Fair value hedge
Senior Notes AA	10 fixed-to-floating swaps	\$750.0	1/11 to 2/16	3.2% to 1.2%	Fair value hedge
Non-Hedged Swaps	2 floating-to-fixed swaps	\$250.0	9/07 to 8/11	0.3% to 4.8%	Mark-to-market
Non-Hedged Swaps	6 floating-to-fixed swaps	\$600.0	5/10 to 7/14	0.3% to 2.0%	Mark-to-market

Interest rate swaps exchange the stated interest rate paid on a notional amount of debt for the fixed or floating interest rate stipulated in the derivative instrument. Interest expense for the three months ended June 30, 2011 and 2010 reflects an increase of \$2.2 million and a decrease of \$0.8 million, respectively, attributable to interest rate swaps. For the six months ended June 30, 2011 and 2010, such swaps resulted in a decrease in interest expense of \$7.5 million and \$2.2 million, respectively.

The following table summarizes our forward starting interest rate swaps, which hedge the expected underlying benchmark interest rates related to forecasted issuances of debt, outstanding at June 30, 2011:

Hedged Transaction	Number and Type of Derivatives Employed	Notional Amount	Expected Termination Date	Average Rate Locked	Accounting Treatment
Future debt offering	10 forward starting swaps	\$500.0	2/12	4.5%	Cash flow hedge
Future debt offering	5 forward starting swaps	\$250.0	8/12	3.9%	Cash flow hedge
Future debt offering	16 forward starting swaps	\$1,000.0	3/13	3.7%	Cash flow hedge

In connection with the issuance of Senior Notes AA and BB (see Note 9), we settled three forward starting swaps in January 2011 having a notional amount of \$250 million, resulting in a loss of \$5.7 million. This loss will be amortized to earnings (as an increase in interest expense) using the effective interest method over the forecasted hedged period.

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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 such price risks, we enter into commodity derivative instruments such as physical forward agreements, futures contracts, fixed-for-float swaps, basis swaps and options contracts. The following table summarizes our commodity derivative instruments outstanding at June 30, 2011:

Derivative Purpose	Volume (1)		Accounting Treatment
	Current (2)	Long-Term (2)	
Derivatives designated as hedging instruments:			
Enterprise:			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction (“PTR”) (3)	31.9 Bcf	n/a	Cash flow hedge
Forecasted sales of NGLs (4)	6.6 MMBbbls	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchases of NGLs	0.1 MMBbbls	n/a	Cash flow hedge
Forecasted sales of octane enhancement products	2.0 MMBbbls	n/a	Cash flow hedge
Natural gas marketing:			
Natural gas storage inventory management activities	2.8 Bcf	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products	2.3 MMBbbls	n/a	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products	2.3 MMBbbls	n/a	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products	1.1 MMBbbls	n/a	Cash flow hedge
Forecasted sales of refined products	1.2 MMBbbls	n/a	Cash flow hedge
Crude oil marketing:			
Forecasted purchases of crude oil	1.1 MMBbbls	n/a	Cash flow hedge
Forecasted sales of crude oil	1.9 MMBbbls	n/a	Cash flow hedge
Derivatives not designated as hedging instruments:			
Enterprise:			
Natural gas risk management activities (5,6)	385.8 Bcf	69.0 Bcf	Mark-to-market
Refined products risk management activities (6)	3.4 MMBbbls	n/a	Mark-to-market
Crude oil risk management activities (6)	5.7 MMBbbls	n/a	Mark-to-market
Duncan Energy Partners:			
Natural gas risk management activities (6)	0.2 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 designated as cash flow hedges, derivatives designated as fair value hedges and derivatives not designated as hedging instruments is June 2012, January 2012 and December 2013, respectively.

- (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) Forecasted sales of NGL volumes under Natural gas processing exclude 1.6 MMBbls of additional hedges executed under contracts that have been designated as normal sales agreements.
- (5) Current and long-term volumes include approximately 75.5 Bcf and 2.8 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.

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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 natural gas processing activities. We achieve this objective by using physical and financial instruments to lock in the purchase prices of natural gas consumed as PTR and the sales prices of the related NGL products. This program consists of (i) the forward sale of a portion of our expected equity NGL production at fixed prices through December 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.

Certain basis swaps, basis spread options and other derivative instruments not designated as hedging instruments are used to manage market risks associated with anticipated purchases and sales of natural gas necessary to optimize our owned and contractually committed transportation and storage capacity.

There is some uncertainty involved in the timing of these transactions often due to the development of more favorable profit opportunities or when spreads are insufficient to cover variable costs thus reducing the likelihood that the transactions will occur as originally forecasted. As a result of this timing uncertainty, these derivative instruments do not qualify for hedge accounting even though they are effective at managing the risk exposures of these assets.

The earnings volatility caused by fluctuations in non-cash, mark-to-market earnings cannot be predicted and the impact to earnings could be material.

Credit-Risk Related Contingent Features in Derivative Instruments

A limited number of our commodity derivative instruments include provisions related to credit ratings and/or adequate assurance clauses. A credit rating provision provides for a counterparty to demand immediate full or partial payment to cover a net liability position upon the loss of a stipulated credit rating. An adequate assurance clause provides for a counterparty to demand immediate full or partial payment to cover a net liability position should reasonable grounds for insecurity arise with respect to contractual performance by either party. At June 30, 2011, the aggregate fair value of our over-the-counter derivative instruments in a net liability position was \$0.2 million. The maximum potential cash payment under the contracts containing a credit rating contingent feature is \$1.4 million. The potential for derivatives with contingent features to enter a net liability position may change in the future as commodity positions and prices fluctuate.

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

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

	Asset Derivatives				Liability Derivatives			
	June 30, 2011		December 31, 2010		June 30, 2011		December 31, 2010	
	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	\$ 51.1	Other current assets	\$ 30.3	Other current liabilities	\$ 42.4	Other current liabilities	\$ 5.5
Interest rate derivatives	Other assets	49.4	Other assets	77.8	Other liabilities	6.1	Other liabilities	26.2
Total interest rate derivatives		100.5		108.1		48.5		31.7
Commodity derivatives	Other current assets	46.6	Other current assets	46.3	Other current liabilities	108.8	Other current liabilities	93.0
Commodity derivatives	Other assets	--	Other assets	1.0	Other liabilities	--	Other liabilities	1.7
Total commodity derivatives (1)		46.6		47.3		108.8		94.7
Total derivatives designated as hedging instruments		\$ 147.1		\$ 155.4		\$ 157.3		\$ 126.4
Derivatives not designated as hedging instruments								
Interest rate derivatives	Other current assets	\$ --	Other current assets	\$ --	Other current liabilities	\$ 15.7	Other current liabilities	\$ 21.0
Interest rate derivatives	Other assets	--	Other assets	--	Other liabilities	6.0	Other liabilities	0.9
Total interest rate derivatives		--		--		21.7		21.9
Commodity derivatives	Other current assets	36.4	Other current assets	38.6	Other current liabilities	40.6	Other current liabilities	41.2
Commodity derivatives	Other assets	4.5	Other assets	4.5	Other liabilities	2.1	Other liabilities	5.4
Total commodity derivatives		40.9		43.1		42.7		46.6
Foreign currency derivatives	Other assets	--	Other assets	0.3	Other liabilities	--	Other liabilities	0.1

Total derivatives not designated as hedging instruments	\$ 40.9	\$ 43.4	\$ 64.4	\$ 68.6
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(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 presented:

Derivatives in Fair Value Hedging Relationships	Location	Gain/(Loss) Recognized in Income on Derivative			
		For the Three Months Ended June 30,		For the Six Months Ended June 30,	
		2011	2010	2011	2010
Interest rate derivatives	Interest expense	\$21.1	\$11.6	\$8.8	\$19.0
Commodity derivatives	Revenue	(1.6)	4.7	(1.3)	2.9
Total		\$19.5	\$16.3	\$7.5	\$21.9

Derivatives in Fair Value Hedging Relationships	Location	Gain/(Loss) Recognized in Income on Hedged Item			
		For the Three Months Ended June 30,		For the Six Months Ended June 30,	
		2011	2010	2011	2010
Interest rate derivatives	Interest expense	\$(21.0)	\$(10.8)	\$(9.7)	\$(18.2)
Commodity derivatives	Revenue	0.2	(4.3)	(1.1)	(2.4)
Total		\$(20.8)	\$(15.1)	\$(10.8)	\$(20.6)

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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 presented:

Derivatives in Cash Flow Hedging Relationships	Change in Value Recognized in Other Comprehensive Income/(Loss) on Derivative (Effective Portion)			
	For the Three Months		For the Six Months	
	Ended June 30,		Ended June 30,	
	2011	2010	2011	2010
Interest rate derivatives	\$(60.1)	\$(79.3)	\$(46.0)	\$(86.8)
Commodity derivatives – Revenue (1)	(19.4)	93.5	(174.8)	86.4
Commodity derivatives – Operating costs and expenses	(2.3)	(1.5)	1.7	(53.3)
Foreign currency derivatives	--	(0.1)	--	(0.2)
Total	\$(81.8)	\$12.6	\$(219.1)	\$(53.9)

(1) The increase in other comprehensive loss during 2011 is primarily due to the impact of rising crude oil, refined products and NGL prices on our derivative instruments designated as cash flow hedges of future physical sales transactions.

Derivatives in Cash Flow Hedging Relationships	Location	Gain/(Loss) Reclassified from Accumulated Other Comprehensive Income/(Loss) to Income (Effective Portion)			
		For the Three Months		For the Six Months	
		Ended June 30,		Ended June 30,	
		2011	2010	2011	2010
Interest rate derivatives	Interest expense	\$(1.5)	\$(7.2)	\$(3.0)	\$(13.3)
Commodity derivatives	Revenue	(79.3)	18.3	(148.5)	2.5
Commodity derivatives	Operating costs and expenses	4.5	(16.8)	4.8	(17.5)
Foreign currency derivatives	Other income	--	--	--	0.3
Total		\$(76.3)	\$(5.7)	\$(146.7)	\$(28.0)

Derivatives in Cash Flow Hedging Relationships	Location	Gain Recognized in Income on Derivative (Ineffective Portion)			
		For the Three Months		For the Six Months	
		Ended June 30,		Ended June 30,	
		2011	2010	2011	2010
Commodity derivatives	Revenue	\$0.3	\$--	\$0.2	\$--
Commodity derivatives	Operating costs and expenses	--	3.5	--	2.9
Total		\$0.3	\$3.5	\$0.2	\$2.9

Over the next twelve months, we expect to reclassify \$7.9 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 \$61.2 million of losses attributable to commodity derivative instruments from accumulated other comprehensive loss to earnings, \$29.4 million as an increase in operating costs and expenses and \$31.8 million as a decrease in revenue.

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 presented:

Derivatives Not Designated as Hedging Instruments	Location	Gain/(Loss) Recognized in Income on Derivative			
		For the Three Months Ended June 30,		For the Six Months Ended June 30,	
		2011	2010	2011	2010
Interest rate derivatives	Interest expense	\$(11.9)	\$--	\$(10.5)	\$--
Commodity derivatives	Revenue	9.5	(8.9)	13.3	(5.0)
Commodity derivatives	Operating costs and expenses	--	--	--	(1.5)
Total		\$(2.4)	\$(8.9)	\$2.8	\$(6.5)

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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 following table sets forth, by level within the fair value hierarchy, the carrying values of our financial assets and liabilities at the date indicated. These assets and liabilities are measured on a recurring basis and are classified within the table based on the lowest level of input that is significant to their respective fair value. Our assessment of the relative significance of such inputs requires judgment.

	At June 30, 2011			
	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Financial assets:				
Interest rate derivatives	\$--	\$100.5	\$ --	\$100.5
Commodity derivatives	31.9	49.0	6.6	87.5
Total	\$31.9	\$149.5	\$ 6.6	\$188.0
Financial liabilities:				
Interest rate derivatives	\$--	\$70.2	\$ --	\$70.2
Commodity derivatives	66.2	80.8	4.5	151.5
Total	\$66.2	\$151.0	\$ 4.5	\$221.7

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 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

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assumptions (i) are 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 financial models that incorporate the implied forward London Interbank Offered Rate yield curve for the same period as the future interest swap settlements.

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

Transfers within the fair value hierarchy routinely occur for certain term contracts as prices and other inputs used for the valuation of future delivery periods become more observable with the passage of time. Other transfers are made periodically in response to changing market conditions that affect liquidity, price observability and other inputs used in determining valuations. Based on an assessment completed during the first quarter of 2011, we transferred ethane, normal butane and natural gasoline-based contracts with terms ranging from two months to one year from Level 3 to Level 2. These transfers were made after a sustained increase in the observability of forward prices for these energy commodity products relative to the date range stated above as demonstrated by narrowing bid/offer spreads, higher transaction volumes and more activity and liquidity for these types of contracts. With the exception of the transfers noted above, no other transfers were made between fair value levels during the year-to-date period.

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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 presented:

	For the Six Months Ended June 30,	
	2011	2010
Balance, January 1	\$(25.9)	\$5.7
Total gains (losses) included in:		
Net income (1)	(0.5)	(3.6)
Other comprehensive income (loss)	16.2	(8.3)
Settlements	0.8	3.6
Transfers out of Level 3 (2)	9.8	--
Balance, March 31	0.4	(2.6)
Total gains included in:		
Net income (1)	1.9	16.2
Other comprehensive income (loss)	--	22.2
Settlements	(0.2)	(16.2)
Transfers out of Level 3	--	0.2
Balance, June 30	\$2.1	\$19.8

(1) There were \$2.0 million and \$1.8 million of unrealized gains included in these amounts for the three and six months ended June 30, 2011, respectively. There were \$2.8 million and \$2.3 million of unrealized losses included in these amounts for the three and six months ended June 30, 2010, respectively.

(2) Transfers out of Level 3 into Level 2 were primarily due to the change in observability of forward NGL prices as described above.

Nonfinancial Assets and Liabilities

During the six months ended June 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. The non-cash asset impairment charges we recorded during the six months ended June 30, 2010 are a component of operating costs and expenses.

Note 5. Inventories

Inventories primarily consist of NGLs, petrochemicals and refined products, crude oil and natural gas volumes that are valued at the lower of average cost or market. We capitalize, as a cost of inventory, shipping and handling charges (e.g., pipeline transportation and storage fees) and other related costs associated with purchased volumes. As volumes are sold and delivered out of inventory, the cost of these volumes (including freight-in charges that have been capitalized as part of inventory cost) are charged to operating costs and expenses. Our inventory amounts by product type were as follows at the dates indicated:

	June 30, 2011	December 31, 2010
NGLs	\$500.8	\$548.3

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Petrochemicals and refined products	344.3	399.7
Crude oil	92.2	121.1
Natural gas	56.3	64.7
Other	0.5	0.2
	\$994.1	\$1,134.0

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

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our inventory levels have decreased since December 31, 2010 due to seasonal supply and demand fluctuations.

Due to fluctuating commodity prices, we recognize lower of cost or market (“LCM”) adjustments when the carrying value of our inventories exceeds their net realizable value. These non-cash charges are a component of cost of sales in the period they are recognized. To the extent our commodity hedging strategies address inventory-related price risks and are successful, these inventory valuation adjustments are mitigated or offset. See Note 4 for a description of our commodity hedging activities. The following table summarizes our cost of sales and LCM adjustments for the periods presented:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
Cost of sales (1)	\$9,790.3	\$6,343.2	\$18,609.6	\$13,685.5
Lower of cost or market adjustments	0.5	1.2	1.7	6.9

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

Note 6. Property, Plant and Equipment

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

	Estimated Useful Life in Years	June 30, 2011	December 31, 2010
Plants, pipelines and facilities (1)	3-45 (6)	\$19,814.8	\$19,388.4
Underground and other storage facilities (2)	5-40 (7)	1,538.9	1,477.8
Platforms and facilities (3)	20-31	637.5	637.5
Transportation equipment (4)	3-10	125.4	119.1
Marine vessels (5)	15-30	574.6	560.0
Land		130.1	123.4
Construction in progress		2,923.1	1,607.2
Total		25,744.4	23,913.4
Less accumulated depreciation		4,945.5	4,580.5
Property, plant and equipment, net		\$20,798.9	\$19,332.9

(1) Plants and pipelines include processing plants; NGL, natural gas, crude oil and petrochemical and refined products 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 tractor-trailer tank trucks and other vehicles and similar assets used in our operations.

- (5) Marine vessels include tow boats, barges and related equipment used in our marine transportation business.
- (6) In general, the estimated useful lives of major assets within this category are: 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 assets within this category are: underground storage facilities, 5-35 years; storage tanks, 10-40 years; and water wells, 5-35 years.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
Depreciation expense (1)	\$189.8	\$187.7	\$376.3	\$368.0
Capitalized interest (2)	24.8	10.5	42.0	21.0

(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.

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 contractual AROs primarily result from right-of-way agreements associated with our pipeline operations and leases of plant sites. In addition, we have recorded AROs based on government regulations triggered by the abandonment or retirement of (i) certain underground storage facilities and related above-ground brine storage pits, (ii) offshore Gulf of Mexico assets and (iii) certain marine vessels. Our AROs may also result from regulatory requirements associated with the renovation or demolition of certain assets containing hazardous substances such as asbestos.

The following table presents information regarding our AROs since December 31, 2010:

ARO liability balance, December 31, 2010	\$97.1
Revisions in estimated cash flows	4.5
Accretion expense	3.1
Liabilities settled during period	(1.6)
Liabilities incurred during period	0.1
ARO liability balance, June 30, 2011	\$103.2

Property, plant and equipment at June 30, 2011 and December 31, 2010 includes \$38.0 million and \$34.1 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset. The following table presents our accretion expense forecasts for AROs for the periods presented:

Remainder of				
2011	2012	2013	2014	2015
\$3.3	\$5.2	\$5.6	\$6.1	\$5.8

Certain of our unconsolidated affiliates have AROs recorded at June 30, 2011 and December 31, 2010 relating to contractual agreements and regulatory requirements. These amounts are immaterial to our consolidated financial statements.

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Note 7. Investments in Unconsolidated Affiliates

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

	Ownership Interest at June 30, 2011	June 30, 2011	December 31, 2010
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C.	13.1%	\$ 34.5	\$ 31.9
K/D/S Promix, L.L.C. ("Promix")	50%	41.9	43.5
Baton Rouge Fractionators LLC	32.2%	21.2	21.9
Skelly-Belvieu Pipeline Company, L.L.C.	50%	34.1	34.2
Onshore Natural Gas Pipelines & Services:			
Evangeline (1)	49.5%	5.6	6.4
White River Hub, LLC ("White River Hub")	50%	25.8	26.2
Onshore Crude Oil Pipelines & Services:			
Seaway Crude Pipeline Company ("Seaway")	50%	174.1	172.2
Offshore Pipelines & Services:			
Poseidon Oil Pipeline Company, L.L.C. ("Poseidon")	36%	56.2	57.2
Cameron Highway Oil Pipeline Company	50%	227.8	233.7
Deepwater Gateway, L.L.C.	50%	97.0	98.4
Neptune Pipeline Company, L.L.C.	25.7%	53.0	53.9
Petrochemical & Refined Products Services:			
Baton Rouge Propylene Concentrator, LLC	30%	9.9	10.1
Centennial Pipeline LLC ("Centennial")	50%	59.4	63.1
Other (2)	Various	3.6	3.6
Other Investments:			
Energy Transfer Equity	15.5%	1,241.8	1,436.8
Total		\$ 2,085.9	\$ 2,293.1

(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.

The Other Investments segment consists of noncontrolling ownership interests in Energy Transfer Equity, which is accounted for using the equity method. At June 30, 2011, we owned 34,526,090 common units of Energy Transfer Equity representing approximately 15.5% of their common units outstanding. Our equity investments are part of our long-term business strategy; however, we may from time-to-time elect to divest of a portion of our long-term equity investments in order to redeploy capital. In May 2011, we sold 4,450,000 Energy Transfer Equity common units for net cash proceeds of \$165.8 million and recorded a gain of \$5.4 million on the sale. In July 2011, we sold an

additional 4,114,136 Energy Transfer Equity common units in two separate transactions for a combined \$167.7 million. Proceeds from these transactions were used for general partnership purposes, including funding of capital expenditures. Following the July transactions, we own 30,411,954 Energy Transfer Equity common units representing approximately 13.6% of their common units outstanding.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
NGL Pipelines & Services	\$6.2	\$3.7	\$12.1	\$7.0
Onshore Natural Gas Pipelines & Services	1.5	0.9	2.7	2.2
Onshore Crude Oil Pipelines & Services	(1.6)	3.6	(2.1)	5.9
Offshore Pipelines & Services	6.6	11.1	14.9	22.9
Petrochemical & Refined Products Services	(4.3)	(2.6)	(9.3)	(5.3)
Other Investments	2.7	(5.7)	9.0	4.9
Total	\$11.1	\$11.0	\$27.3	\$37.6

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

	June 30, 2011	December 31, 2010
NGL Pipelines & Services	\$25.2	\$25.7
Onshore Crude Oil Pipelines & Services	19.5	19.7
Offshore Pipelines & Services	15.4	16.0
Petrochemical & Refined Products Services	3.0	3.0
Other Investments (1)	1,334.8	1,525.1
Total	\$1,397.9	\$1,589.5

(1) Holdings' investment in Energy Transfer Equity exceeded its share of the historical cost of the underlying net assets of such investee by \$1.66 billion in May 2007. At June 30, 2011, this basis differential decreased to \$1.33 billion (after taking into account related amortization amounts and the sale of 4.45 million Energy Transfer Equity common units in May 2011) and consisted of the following: \$421.2 million attributed to fixed assets; \$451.5 million attributed to the incentive distribution rights (an indefinite-life intangible asset) held by Energy Transfer Equity in the cash flows of ETP; \$166.9 million attributed to amortizable intangible assets and \$295.2 million attributed to equity method goodwill. These unamortized excess cost amounts are being amortized over their estimated economic lives of 20-27 years, as applicable.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
NGL Pipelines & Services	\$0.2	\$0.3	\$0.5	\$0.5
Onshore Crude Oil Pipelines & Services	0.2	0.2	0.4	0.4
Offshore Pipelines & Services	0.3	0.3	0.6	0.6

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Petrochemical & Refined Products Services	--	0.2	--	0.9
Other Investments	8.4	9.1	17.5	18.3
Total	\$9.1	\$10.1	\$19.0	\$20.7

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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 presented:

	Summarized Income Statement Information for the Three Months Ended					
	June 30, 2011			June 30, 2010		
	Revenues	Operating Income (Loss)	Net Income (Loss)	Revenues	Operating Income (Loss)	Net Income (Loss)
NGL Pipelines & Services	\$ 116.4	\$ 30.5	\$ 30.6	\$ 74.7	\$ 13.4	\$ 13.4
Onshore Natural Gas Pipelines & Services	54.7	2.7	2.7	53.7	1.9	1.9
Onshore Crude Oil Pipelines & Services	9.6	(2.1)	(2.1)	22.0	10.8	10.8
Offshore Pipelines & Services	43.7	17.7	17.5	51.4	26.8	26.7
Petrochemical & Refined Products Services	9.2	(5.4)	(7.6)	15.6	(2.6)	(6.5)
Other Investments (1)	1,974.9	260.6	66.3	1,368.5	179.4	19.2

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

	Summarized Income Statement Information for the Six Months Ended					
	June 30, 2011			June 30, 2010		
	Revenues	Operating Income (Loss)	Net Income (Loss)	Revenues	Operating Income (Loss)	Net Income (Loss)
NGL Pipelines & Services	\$ 216.5	\$ 53.9	\$ 54.0	\$ 149.5	\$ 26.5	\$ 26.4
Onshore Natural Gas Pipelines & Services	90.2	5.3	5.3	96.0	4.4	4.3
Onshore Crude Oil Pipelines & Services	20.8	(1.6)	(1.6)	40.5	18.1	18.1
Offshore Pipelines & Services	90.0	36.6	36.2	106.4	56.0	55.4
Petrochemical & Refined Products Services	19.3	(12.4)	(16.8)	24.2	(2.0)	(6.8)
Other Investments (1)	3,964.0	624.8	154.9	3,240.5	518.3	132.0

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

With the exception of Energy Transfer Equity, all of these investments are in untraded privately held companies, the fair values of which are not practicable to estimate. At June 30, 2011, the fair value of our investment in Energy Transfer Equity was \$1.55 billion based on the closing market price of Energy Transfer Equity's common units on that date.

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Note 8. Intangible Assets and Goodwill

Identifiable Intangible Assets

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

	June 30, 2011			December 31, 2010		
	Gross Value	Accum. Amort.	Carrying Value	Gross Value	Accum. Amort.	Carrying Value
NGL Pipelines & Services:						
Customer relationship intangibles	\$340.8	\$(117.6)	) \$223.2	\$340.8	\$(106.7)	) \$234.1
Contract-based intangibles	287.5	(161.4)	) 126.1	322.2	(176.6)	) 145.6
Segment total	628.3	(279.0)	) 349.3	663.0	(283.3)	) 379.7
Onshore Natural Gas Pipelines & Services:						
Customer relationship intangibles	1,163.6	(185.5)	) 978.1	1,163.6	(160.8)	) 1,002.8
Contract-based intangibles	551.5	(323.6)	) 227.9	565.3	(322.0)	) 243.3
Segment total	1,715.1	(509.1)	) 1,206.0	1,728.9	(482.8)	) 1,246.1
Onshore Crude Oil Pipelines & Services:						
Customer relationship intangibles	9.7	(3.9)	) 5.8	9.7	(3.7)	) 6.0
Contract-based intangibles	0.4	(0.2)	) 0.2	0.4	(0.2)	) 0.2
Segment total	10.1	(4.1)	) 6.0	10.1	(3.9)	) 6.2
Offshore Pipelines & Services:						
Customer relationship intangibles	205.8	(123.8)	) 82.0	205.8	(118.1)	) 87.7
Contract-based intangibles	1.2	(0.3)	) 0.9	1.2	(0.2)	) 1.0
Segment total	207.0	(124.1)	) 82.9	207.0	(118.3)	) 88.7
Petrochemical & Refined Products Services:						
Customer relationship intangibles	104.8	(26.5)	) 78.3	104.7	(23.8)	) 80.9
Contract-based intangibles	57.8	(23.7)	) 34.1	60.3	(20.2)	) 40.1
Segment total	162.6	(50.2)	) 112.4	165.0	(44.0)	) 121.0
Total all segments	\$2,723.1	\$(966.5)	) \$1,756.6	\$2,774.0	\$(932.3)	) \$1,841.7

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
NGL Pipelines & Services	\$10.0	\$10.1	\$20.4	\$19.4
Onshore Natural Gas Pipelines & Services	20.2	18.1	40.1	32.3

Onshore Crude Oil Pipelines & Services	0.1	0.1	0.2	0.2
Offshore Pipelines & Services	2.8	3.2	5.8	6.6
Petrochemical & Refined Products Services	4.3	2.6	8.6	5.2
Total	\$37.4	\$34.1	\$75.1	\$63.7

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

Remainder of 2011	2012	2013	2014	2015
\$69.7	\$132.4	\$127.1	\$127.2	\$125.8

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

Customer relationship intangible assets. Customer relationship intangible assets represent the estimated economic value assigned to certain relationships acquired in connection with business combinations and asset purchases whereby (i) we acquired information about or access to customers and now have regular contact with them and (ii) the customers now have the ability to make direct contact with

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us. Customer relationships may arise from contractual arrangements (such as supplier contracts and service contracts) and through means other than contracts, such as through regular contact by sales or service representatives. At June 30, 2011, the carrying value of our customer relationship intangible assets was \$1.37 billion.

Contract-based intangible assets. Contract-based intangible assets represent specific commercial rights we acquired in connection with business combinations or asset purchases. At June 30, 2011, the carrying value of our contract-based intangible assets was \$389.2 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 beginning of each fiscal year, and more frequently, if circumstances indicate it is probable that the fair value of goodwill is below its carrying amount. The following table presents changes in the carrying amount of goodwill for the period presented:

	NGL Pipelines & Services	Onshore Natural Gas Pipelines & Services	Onshore Crude Oil Pipelines & Services	Offshore Pipelines & Services	Petrochemical & Refined Products Services	Consolidated Total
Balance at December 31, 2010						
(1)	\$341.2	\$311.1	\$311.2	\$82.1	\$ 1,062.1	\$ 2,107.7
Goodwill adjustment (2)	--	--	--	--	(0.6)	(0.6)
Balance at June 30, 2011 (1)	\$341.2	\$311.1	\$311.2	\$82.1	\$ 1,061.5	\$ 2,107.1

(1) The total carrying amount of goodwill at June 30, 2011 and December 31, 2010 is presented net of \$1.3 million of accumulated impairment charges.

(2) Purchase price adjustment related to a marine business combination completed in November 2010.

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%).

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Note 9. Debt Obligations

Our consolidated debt obligations consisted of the following at the dates indicated (arranged by company and maturity date):

	June 30, 2011	December 31, 2010
EPO senior debt obligations:		
Senior Notes B, 7.50% fixed-rate, due February 2011	\$--	\$450.0
Senior Notes S, 7.625% fixed-rate, due February 2012	490.5	490.5
Senior Notes P, 4.60% fixed-rate, due August 2012	500.0	500.0
\$1.75 Billion Multi-Year Revolving Credit Facility, variable-rate, due November 2012	--	648.0
Senior Notes C, 6.375% fixed-rate, due February 2013	350.0	350.0
Senior Notes T, 6.125% fixed-rate, due February 2013	182.5	182.5
Senior Notes M, 5.65% fixed-rate, due April 2013	400.0	400.0
Senior Notes U, 5.90% fixed-rate, due April 2013	237.6	237.6
Senior Notes O, 9.75% fixed-rate, due January 2014	500.0	500.0
Senior Notes G, 5.60% fixed-rate, due October 2014	650.0	650.0
Senior Notes I, 5.00% fixed-rate, due March 2015	250.0	250.0
Senior Notes X, 3.70% fixed-rate, due June 2015	400.0	400.0
Senior Notes AA, 3.20% fixed-rate, due February 2016	750.0	--
Senior Notes L, 6.30% fixed-rate, due September 2017	800.0	800.0
Senior Notes V, 6.65% fixed-rate, due April 2018	349.7	349.7
Senior Notes N, 6.50% fixed-rate, due January 2019	700.0	700.0
Senior Notes Q, 5.25% fixed-rate, due January 2020	500.0	500.0
Senior Notes Y, 5.20% fixed-rate, due September 2020	1,000.0	1,000.0
Senior Notes D, 6.875% fixed-rate, due March 2033	500.0	500.0
Petal GO Zone Bonds, variable-rate, due August 2034	57.5	57.5
Senior Notes H, 6.65% fixed-rate, due October 2034	350.0	350.0
Senior Notes J, 5.75% fixed-rate, due March 2035	250.0	250.0
Senior Notes W, 7.55% fixed-rate, due April 2038	399.6	399.6
Senior Notes R, 6.125% fixed-rate, due October 2039	600.0	600.0
Senior Notes Z, 6.45% fixed-rate, due September 2040	600.0	600.0
Senior Notes BB, 5.95% fixed-rate, due February 2041	750.0	--
TEPPCO senior debt obligations:		
TEPPCO Senior Notes, 7.625% fixed-rate, due February 2012	9.5	9.5
TEPPCO Senior Notes, 6.125% fixed-rate, due February 2013	17.5	17.5
TEPPCO Senior Notes, 5.90% fixed-rate, due April 2013	12.4	12.4
TEPPCO Senior Notes, 6.65% fixed-rate, due April 2018	0.3	0.3
TEPPCO Senior Notes, 7.55% fixed-rate, due April 2038	0.4	0.4
Duncan Energy Partners' debt obligations:		
DEP Term Loan, variable-rate, due December 2011	282.3	282.3
DEP \$850 Million Multi-Year Revolving Credit Facility, variable-rate, due October 2013	467.5	106.0
DEP \$400 Million Term Loan Facility, variable-rate, due October 2013	400.0	400.0
Total principal amount of senior debt obligations	12,757.3	11,993.8
EPO Junior Subordinated Notes A, fixed/variable-rate, due August 2066	550.0	550.0

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EPO Junior Subordinated Notes C, fixed/variable-rate, due June 2067	285.8	285.8
EPO Junior Subordinated Notes B, fixed/variable-rate, due January 2068	682.7	682.7
TEPPCO Junior Subordinated Notes, fixed/variable-rate, due June 2067	14.2	14.2
Total principal amount of senior and junior debt obligations	14,290.0	13,526.5
Other, non-principal amounts:		
Change in fair value of debt hedged in fair value hedging relationship (1)	59.0	49.3
Unamortized discounts, net of premiums	(29.1)	(24.0)
Unamortized deferred net gains related to terminated interest rate swaps (1)	7.1	11.7
Total other, non-principal amounts	37.0	37.0
Less current maturities of debt (2)	(782.3)	(282.3)
Total long-term debt	\$13,544.7	\$13,281.2

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

(2) We expect to refinance the current maturities of our debt obligations prior to their maturity.

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Letters of Credit

At June 30, 2011, EPO had a \$50.0 million letter of credit outstanding related to its commodity derivative instruments and a \$58.3 million letter of credit outstanding related to its Petal GO Zone Bonds. These letter of credit facilities do not reduce the amount available for borrowing under EPO's Multi-Year Revolving Credit Facility.

Parent-Subsidiary Guarantor Relationships

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

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

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 or amounts of our consolidated debt obligations since those reported in our 2010 Form 10-K.

At June 30, 2011, EPO's Multi-Year Revolving Credit Facility had no borrowings outstanding. Available borrowing capacity under this revolving credit facility is \$1.75 billion.

Issuance of Senior Notes AA and BB. In January 2011, EPO issued \$750.0 million in principal amount of 5-year unsecured Senior Notes AA and \$750.0 million in principal amount of 30-year unsecured Senior Notes BB. Senior Notes AA were issued at 99.901% of their principal amount, have a fixed interest rate of 3.20%, and mature on February 1, 2016. Senior Notes BB were issued at 99.317% of their principal amount, have a fixed interest rate of 5.95%, and mature on February 1, 2041. Net proceeds from the issuance of Senior Notes AA and BB were used (i) to repay \$450.0 million in aggregate principal amount of Senior Notes B that matured in February 2011, (ii) to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and (iii) for general company purposes.

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

Cancellation of Canadian Revolving Credit Facility. As of December 31, 2010, there were no debt obligations outstanding under this \$30 million revolving credit facility. This facility was cancelled in January 2011.

Covenants

After giving effect to the limited waivers described below, we were in compliance with the financial covenants of our consolidated debt agreements at June 30, 2011.

Duncan Energy Partners' revolving credit and term loan agreements include various operating and financial covenants, including provisions for maintaining a leverage ratio (i.e., a debt to Consolidated Adjusted EBITDA ratio (as such terms are defined in the underlying lending agreements)) of less than 5.00x as of the last day of any fiscal quarter. Principally as a result of increased capital spending on the Haynesville Extension project and working capital needs, Duncan Energy Partners leverage ratio at June

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30, 2011 was determined to be 5.04x, which (but for the waivers described below) would have exceeded the maximum leverage ratio allowed under its lending agreements. Duncan Energy Partners expects that its leverage ratio as of September 30, 2011 will also exceed 5.00x. However, after the Haynesville Extension enters full commercial operations (expected in the fourth quarter of 2011), Duncan Energy Partners anticipates that the ratio will be less than 5.00x as of December 31, 2011.

As a result of the foregoing, Duncan Energy Partners and its lenders entered into limited waiver agreements on June 30, 2011 with respect to the quarterly leverage ratio covenant. The leverage ratio covenant is waived for the fiscal quarters ending June 30, 2011 and September 30, 2011. The limited waiver agreements will provide Duncan Energy Partners additional financial flexibility in light of its capital spending requirements for the Haynesville Extension natural gas pipeline project.

Information Regarding Variable Interest Rates Paid

The following table presents the range of interest rates and weighted-average interest rates paid on our consolidated variable-rate debt obligations during the six months ended June 30, 2011:

	Range of Interest Rates Paid	Weighted-Average Interest Rate Paid
EPO Multi-Year Revolving Credit Facility	0.69% to 3.25%	0.81%
DEP Term Loan	1.06% to 1.26%	1.15%
DEP \$850 Million Multi-Year Revolving Credit Facility	2.01% to 2.16%	2.09%
DEP \$400 Million Term Loan Facility	2.26% to 2.51%	2.40%
Petal GO Zone Bonds	0.10% to 0.33%	0.22%

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 2011	2012	2013	2014	2015	After 2015
Revolving Credit Facilities	\$467.5	\$--	\$--	\$467.5	\$--	\$--	\$--
Senior Notes	11,550.0	--	1,000.0	1,200.0	1,150.0	650.0	7,550.0
Term Loans	682.3	282.3	--	400.0	--	--	--
Junior Subordinated Notes	1,532.7	--	--	--	--	--	1,532.7
Other	57.5	--	--	--	--	--	57.5

Total	\$14,290.0	\$282.3	\$1,000.0	\$2,067.5	\$1,150.0	\$650.0	\$9,140.2
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Debt Obligations of Unconsolidated Affiliates

At June 30, 2011, we had two privately held unconsolidated affiliates – Poseidon and Centennial – with long-term debt obligations. The following table shows (i) our ownership interest in each entity at June 30, 2011, (ii) the total debt of each entity at June 30, 2011 (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 2011	2012	2013	2014	2015	After 2015
Poseidon	36%	\$92.0	\$--	\$--	\$--	\$--	\$92.0	\$--
Centennial	50%	106.4	4.5	8.9	8.6	8.6	8.6	67.2
Total		\$198.4	\$4.5	\$8.9	\$8.6	\$8.6	\$100.6	\$67.2

The credit agreements of Poseidon and Centennial include customary financial and other covenants. These businesses were in compliance with such financial covenants at June 30, 2011. The credit agreements of these unconsolidated affiliates restrict their ability to pay cash dividends or

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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.

In March 2011, Evangeline made the final scheduled payment of \$3.2 million on its subordinated note payable. Following this payment, Evangeline no longer has any debt obligations.

We refinanced the Poseidon revolving credit facility in April 2011. The new replacement facility matures in April 2015 and has a borrowing capacity of \$125 million.

At June 30, 2011 and December 31, 2010, Energy Transfer Equity had approximately \$11.1 billion and \$9.4 billion, respectively, of consolidated debt obligations outstanding. Since we own only limited partner interests in Energy Transfer Equity, we are not liable for its standalone or consolidated indebtedness.

Note 10. Equity and Distributions

Partners' Equity

Pre-Holdings Merger. As discussed in Note 1, the historical comparative financial statements presented herein are the financial statements of Holdings for periods prior to the effective date of the Holdings Merger. The following table summarizes changes in the number of Holdings' limited partner Units outstanding during the six months ended June 30, 2010.

Balance, January 1, 2010	139,191,640
Issuance of Units to directors of the general partner of Holdings	2,991
Balance, June 30, 2010	139,194,631

Post-Holdings Merger. On November 22, 2010, the 139,195,064 Holdings Units outstanding at the effective date of the merger converted at a ratio of 1.5 to one and, as a result, Holdings' unitholders received 208,813,454 Enterprise common units (net of 23 fractional Enterprise common units that were cashed out).

In addition, the historical noncontrolling interest of Holdings related to limited partner interests in Enterprise that were owned by third parties and related parties other than Holdings was reclassified to limited partners' equity at the effective date of the Holdings Merger. See "Noncontrolling Interest" below for information regarding our noncontrolling interest holders.

Following the Holdings Merger, our partners' equity reflects the various classes of limited partner interests of Enterprise (e.g., common units (including restricted common units) and Class B units). The following table summarizes changes in the number of Enterprise's outstanding units since December 31, 2010:

	Common Units	Class B Units	Treasury Units
Balance, December 31, 2010	843,681,572	4,520,431	--
Common units issued in connection with DRIP and EUPP	1,111,905	--	--
Restricted common units issued	1,359,230	--	--
Forfeiture of restricted common units	(75,857)	--	--
Acquisition of treasury units	(226,601)	--	226,601

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Cancellation of treasury units	--	--	(226,601)
Other	(14,301)	--	--
Balance, June 30, 2011	845,835,948	4,520,431	--

The Class B units are not entitled to receive regular quarterly cash distributions for the first sixteen quarters following the closing date of the TEPPCO Merger in October 2009. The Class B units automatically convert into the same number of common units on the date immediately following the

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payment date for the sixteenth regular quarterly distribution following the closing date of the merger. The Class B units are entitled to vote together with the common units as a single class on partnership matters and, except for the payment of distributions, have the same rights and privileges as our common units.

During the six months ended June 30, 2011, 828,545 restricted common unit awards vested and converted to common units. Of this amount, 226,601 were sold back to us by employees to cover related withholding tax requirements. We cancelled such treasury units immediately upon acquisition.

We may issue additional equity or debt securities to assist us in meeting our future liquidity and capital spending requirements. In July 2010, Enterprise, including EPO, filed a universal shelf registration statement (the “2010 Shelf”) with the SEC. The 2010 Shelf allows Enterprise and EPO (on a standalone basis) to issue an unlimited amount of equity and debt securities, respectively. In January 2011, EPO utilized the 2010 Shelf to issue its Senior Notes AA and BB (see Note 9).

Enterprise also has a registration statement on file with the SEC in connection with its distribution reinvestment plan (“DRIP”). After taking into account limited partner units issued under this registration statement through June 30, 2011, Enterprise may issue an additional 27,389,108 common units under its DRIP. The following table reflects the number of common units issued and the net cash proceeds received from Enterprise’s DRIP during the six months ended June 30, 2011:

	Number of Common Units Issued	Net Cash Proceeds
February 2011 issuance	474,706	\$ 19.6
May 2011 issuance	551,058	21.9
Total	1,025,764	\$ 41.5

In May 2011, Enterprise’s employee unit purchase plan (“EUPP”) reached the maximum 1,200,000 common units permitted under the plan and was terminated. A total of 86,141 common units were issued in 2011 under the EUPP, which generated net cash proceeds of \$3.6 million.

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

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 related net gain or loss in accumulated other comprehensive income (loss) must be immediately reclassified.

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

	June 30, 2011	December 31, 2010
Commodity derivative instruments (1)	\$(61.2)	\$(31.8)
Interest rate derivative instruments (1)	(45.1)	(2.1)
Foreign currency translation adjustment (2)	1.7	1.7
Pension and postretirement benefit plans	(1.0)	(0.4)
Proportionate share of other comprehensive loss of Energy Transfer Equity	(1.7)	(1.0)
Subtotal	(107.3)	(33.6)
Amounts attributable to noncontrolling interest	1.1	1.1
Total accumulated other comprehensive loss in partners' equity	\$(106.2)	\$(32.5)

(1) See Note 4 for additional information regarding these components of accumulated other comprehensive income (loss).

(2) Relates to transactions of our Canadian NGL marketing subsidiary.

Noncontrolling Interest

For periods prior to the Holdings Merger, the portion of the income of Enterprise attributable to its limited partner interests owned by third parties and related parties other than Holdings is included in net income attributable to noncontrolling interest as presented on our Unaudited Condensed Statements of Consolidated Operations. Additionally, cash distributions paid to and cash contributions received from the limited partners of Enterprise other than Holdings are reflected as a component of cash distributions paid to and cash contributions received from noncontrolling interest, as appropriate.

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

	June 30, 2011	December 31, 2010
Limited partners of Duncan Energy Partners:		
Third-party owners of Duncan Energy Partners (1)	\$407.3	\$410.4
Related party owners of Duncan Energy Partners (2)	1.7	1.7
Joint venture partners (3)	113.2	115.6
Accumulated other comprehensive loss attributable to noncontrolling interest	(1.1)	(1.1)
Total noncontrolling interest	\$521.1	\$526.6

(1) Consists of non-affiliate public unitholders of Duncan Energy Partners.

(2) Consists of unitholders of Duncan Energy Partners that are related party affiliates.

(3) Represents third-party ownership interests in joint ventures that we consolidate, including Seminole Pipeline Company, Tri-States NGL Pipeline L.L.C., Independence Hub LLC, Rio Grande Pipeline Company, and Wilprise

Pipeline Company LLC.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
Limited partners of Enterprise	\$--	\$284.2	\$--	\$590.7
Limited partners of Duncan Energy Partners	9.4	9.6	17.3	18.3
Joint venture partners	5.4	6.5	11.3	13.8
Total	\$14.8	\$300.3	\$28.6	\$622.8

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

	For the Six Months Ended June 30,	
	2011	2010
Cash distributions paid to noncontrolling interest:		
Limited partners of Enterprise	\$--	\$683.9
Limited partners of Duncan Energy Partners	21.9	21.3
Joint venture partners	12.9	15.3
Total cash distributions paid to noncontrolling interest	\$34.8	\$720.5
Cash contributions from noncontrolling interest:		
Limited partners of Enterprise	\$--	\$960.0
Limited partners of Duncan Energy Partners	1.5	0.8
Joint venture partners	1.1	1.1
Total cash contributions from noncontrolling interest	\$2.6	\$961.9

Cash distributions paid to the limited partners of Enterprise (prior to the Holdings Merger) and Duncan Energy Partners represent the quarterly cash distributions paid by these entities to their unitholders, excluding amounts paid to Holdings that were eliminated in the preparation of our consolidated financial statements. Similarly, cash contributions received from the limited partners of Enterprise (prior to the Holdings Merger) and Duncan Energy Partners represent net cash proceeds each entity received from the issuance of limited partner units, excluding contributions made by Holdings that were eliminated in consolidation.

Cash Distributions

The following table presents our declared quarterly cash distribution rates with respect to the quarters indicated:

	Distribution Per Common Unit	Record Date	Payment Date
2011			
1st Quarter	\$0.5975	04/29/11	05/06/11
2nd Quarter	\$0.6050	07/29/11	08/10/11

The quarterly cash distributions paid on May 6, 2011 and scheduled to be paid on August 10, 2011 exclude 30,610,000 Designated Units (see Note 1).

Note 11. 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 operating income.

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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 interest.

We consolidate the financial statements of Duncan Energy Partners with those of our own. As a result, our consolidated gross operating margin amounts include 100% of the gross operating margin amounts of Duncan Energy Partners.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
Revenues	\$11,216.5	\$7,543.4	\$21,400.2	\$16,087.9
Less: Operating costs and expenses	(10,533.3)	(6,974.2)	(20,070.4)	(14,946.1)
Add: Equity in income of unconsolidated affiliates	11.1	11.0	27.3	37.6
Depreciation, amortization and accretion in operating costs and expenses (1)	233.3	227.0	464.1	439.4
Non-cash asset impairment charges	--	--	--	1.5
Operating lease expenses paid by EPCO	0.1	0.1	0.3	0.3
Losses (gains) from asset sales and related transactions in operating costs and expenses (2)	(5.2)	1.7	(23.6)	(5.6)
Total segment gross operating margin	\$922.5	\$809.0	\$1,797.9	\$1,615.0

(1) Amount is a component of "Depreciation, amortization and accretion" as presented on the Unaudited Condensed Statements of Consolidated Cash Flows.

(2) Amount is a component of "Gains from asset sales and related transactions" as presented on the Unaudited Condensed Statements of Consolidated Cash Flows.

The following table presents a reconciliation of total segment gross operating margin to operating income and further to income before provision for income taxes for the periods presented:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
Total segment gross operating margin	\$922.5	\$809.0	\$1,797.9	\$1,615.0
Adjustments to reconcile total segment gross operating margin to operating income:	(233.3)	(227.0)	(464.1)	(439.4)

Depreciation, amortization and accretion in operating costs and expenses				
Non-cash asset impairment charges	--	--	--	(1.5)
Operating lease expenses paid by EPCO	(0.1)	(0.1)	(0.3)	(0.3)
Gains (losses) from asset sales and related transactions in operating costs and expenses	5.2	(1.7)	23.6	5.6
General and administrative costs	(50.4)	(40.5)	(88.3)	(80.8)
Operating income	643.9	539.7	1,268.8	1,098.6
Other expense, net	(188.0)	(178.8)	(371.3)	(336.6)
Income before provision for income taxes	\$455.9	\$360.9	\$897.5	\$762.0

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

	Reportable Business Segments							
	NGL Pipelines & Services	Onshore Natural Gas Pipelines & Services	Onshore Crude Oil Pipelines & Services	Offshore Pipelines & Services	Petrochemical & Refined Products Services	Other Investment	Adjustments and Eliminations	Consolidated Total
Revenues from third parties:								
Three months ended June 30, 2011	\$ 3,960.1	\$ 862.5	\$ 4,281.6	\$ 61.1	\$ 1,907.0	\$ --	\$ --	\$ 11,072.3
Three months ended June 30, 2010	2,923.8	786.2	2,629.3	85.5	1,002.6	--	--	7,427.4
Six months ended June 30, 2011	8,015.5	1,734.2	7,652.2	121.7	3,482.3	--	--	21,005.9
Six months ended June 30, 2010	6,590.1	1,897.3	5,016.0	172.0	2,064.1	--	--	15,739.5
Revenues from related parties:								
Three months ended June 30, 2011	76.8	64.8	--	2.6	--	--	--	144.2
Three months ended June 30, 2010	55.5	58.7	--	1.8	--	--	--	116.0
Six months ended June 30, 2011	278.2	109.7	--	6.4	--	--	--	394.3
Six months ended June 30, 2010	235.5	109.1	(0.1)	3.9	--	--	--	348.4
Intersegment and intrasegment revenues:								
Three months ended June 30, 2011	3,228.2	253.9	1,477.6	0.1	445.5	--	(5,405.3)	--
Three months ended June 30, 2010	2,407.7	212.7	223.4	0.3	287.2	--	(3,131.3)	--
Six months ended June 30, 2011	6,702.8	524.8	2,184.7	1.8	918.6	--	(10,332.7)	--
Six months ended June 30, 2010	4,954.9	428.3	248.1	0.7	545.0	--	(6,177.0)	--

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Total revenues:								
Three months ended June 30, 2011	7,265.1	1,181.2	5,759.2	63.8	2,352.5	--	(5,405.3)	11,216.5
Three months ended June 30, 2010	5,387.0	1,057.6	2,852.7	87.6	1,289.8	--	(3,131.3)	7,543.4
Six months ended June 30, 2011	14,996.5	2,368.7	9,836.9	129.9	4,400.9	--	(10,332.7)	21,400.2
Six months ended June 30, 2010	11,780.5	2,434.7	5,264.0	176.6	2,609.1	--	(6,177.0)	16,087.9
Equity in income (loss) of unconsolidated affiliates:								
Three months ended June 30, 2011	6.2	1.5	(1.6)	6.6	(4.3)	2.7	--	11.1
Three months ended June 30, 2010	3.7	0.9	3.6	11.1	(2.6)	(5.7)	--	11.0
Six months ended June 30, 2011	12.1	2.7	(2.1)	14.9	(9.3)	9.0	--	27.3
Six months ended June 30, 2010	7.0	2.2	5.9	22.9	(5.3)	4.9	--	37.6
Gross operating margin:								
Three months ended June 30, 2011	497.7	161.1	67.8	53.4	139.8	2.7	--	922.5
Three months ended June 30, 2010	441.0	106.9	25.9	82.8	158.1	(5.7)	--	809.0
Six months ended June 30, 2011	1,002.1	320.3	99.6	114.7	252.2	9.0	--	1,797.9
Six months ended June 30, 2010	878.3	237.2	52.6	163.9	278.1	4.9	--	1,615.0
Segment assets:								
At June 30, 2011	7,673.7	8,276.2	923.6	1,954.7	3,755.4	1,241.8	2,923.1	26,748.5
At December 31, 2010	7,665.5	8,184.8	917.5	2,004.9	3,758.7	1,436.8	1,607.2	25,575.4
Property, plant and equipment, net: (see Note 6)								
At June 30, 2011	6,851.5	6,727.7	432.3	1,355.7	2,508.6	--	2,923.1	20,798.9
At December 31, 2010	6,813.1	6,595.0	427.9	1,390.9	2,498.8	--	1,607.2	19,332.9
Investments in unconsolidated affiliates: (see Note 7)								

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At June 30, 2011	131.7	31.4	174.1	434.0	72.9	1,241.8	--	2,085.9
At December 31, 2010	131.5	32.6	172.2	443.2	76.8	1,436.8	--	2,293.1
Intangible assets, net: (see Note 8)								
At June 30, 2011	349.3	1,206.0	6.0	82.9	112.4	--	--	1,756.6
At December 31, 2010	379.7	1,246.1	6.2	88.7	121.0	--	--	1,841.7
Goodwill: (see Note 8)								
At June 30, 2011	341.2	311.1	311.2	82.1	1,061.5	--	--	2,107.1
At December 31, 2010	341.2	311.1	311.2	82.1	1,062.1	--	--	2,107.7

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
NGL Pipelines & Services:				
Sales of NGLs	\$3,831.5	\$2,804.4	\$7,888.6	\$6,468.5
Sales of other petroleum and related products	0.7	0.7	1.3	1.2
Midstream services	204.7	174.2	403.8	355.9
Total	4,036.9	2,979.3	8,293.7	6,825.6
Onshore Natural Gas Pipelines & Services:				
Sales of natural gas	719.5	655.6	1,432.2	1,630.8
Midstream services	207.8	189.3	411.7	375.6
Total	927.3	844.9	1,843.9	2,006.4
Onshore Crude Oil Pipelines & Services:				
Sales of crude oil	4,257.9	2,603.4	7,606.1	4,970.7
Midstream services	23.7	25.9	46.1	45.2
Total	4,281.6	2,629.3	7,652.2	5,015.9
Offshore Pipelines & Services:				
Sales of natural gas	0.3	0.4	0.6	0.8
Sales of crude oil	2.5	1.9	5.8	4.0
Midstream services	60.9	85.0	121.7	171.1
Total	63.7	87.3	128.1	175.9
Petrochemical & Refined Products Services:				
Sales of other petroleum and related products	1,718.7	871.7	3,101.5	1,804.3
Midstream services	188.3	130.9	380.8	259.8
Total	1,907.0	1,002.6	3,482.3	2,064.1
Total consolidated revenues	\$11,216.5	\$7,543.4	\$21,400.2	\$16,087.9
Consolidated costs and expenses				
Operating costs and expenses:				
Cost of sales related to our marketing activities	\$8,727.5	\$5,693.5	\$16,657.6	\$12,342.7
Depreciation, amortization and accretion	233.3	227.0	464.1	439.4
Losses (gains) from asset sales and related transactions	(5.2)	1.7	(23.6)	(5.6)
Non-cash asset impairment charges	--	--	--	1.5
Other operating costs and expenses	1,577.7	1,052.0	2,972.3	2,168.1
General and administrative costs	50.4	40.5	88.3	80.8
Total consolidated costs and expenses	\$10,583.7	\$7,014.7	\$20,158.7	\$15,026.9

Changes in our revenues and operating costs and expenses period-to-period are explained in part by changes in energy commodity prices. In general, higher energy commodity prices result in an increase in our revenues attributable to the sale of NGLs, natural gas, crude oil and other petroleum and related products; however, these higher commodity prices also increase the associated cost of sales as purchase costs rise.

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Note 12. Related Party Transactions

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
Revenues – related parties:				
Energy Transfer Equity and subsidiaries	\$86.7	\$59.9	\$296.9	\$246.5
Other unconsolidated affiliates	57.5	56.1	97.4	101.9
Total revenue – related parties	\$144.2	\$116.0	\$394.3	\$348.4
Costs and expenses – related parties:				
EPCO and affiliates	\$192.4	\$165.5	\$365.4	\$324.4
Energy Transfer Equity and subsidiaries	223.0	147.2	490.4	324.1
Other unconsolidated affiliates	11.4	9.5	21.6	21.7
Total costs and expenses – related parties	\$426.8	\$322.2	\$877.4	\$670.2

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

	June 30, 2011	December 31, 2010
Accounts receivable - related parties:		
EPCO and affiliates	\$0.1	\$--
Energy Transfer Equity and subsidiaries	12.0	21.4
Other unconsolidated affiliates	25.6	15.4
Total accounts receivable – related parties	\$37.7	\$36.8
Accounts payable - related parties:		
EPCO and affiliates	\$107.2	\$88.0
Energy Transfer Equity and subsidiaries	65.8	36.7
Other unconsolidated affiliates	10.2	8.4
Total accounts payable – related parties	\$183.2	\$133.1

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

§ Enterprise GP, our sole general partner.

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EPCO is a privately held company controlled collectively by the EPCO Trustees. At June 30, 2011, 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 the following limited partner interests in us:

Number of Units	Percentage of Outstanding Units
338,282,914 (1)	39.8%

(1) Includes 4,520,431 Class B units.

Dan Duncan LLC owns 100% of our general partner, Enterprise GP.

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We and Enterprise GP are both separate legal entities apart from each other and apart from EPCO and its other affiliates, with assets and liabilities that are separate from those of EPCO and its other affiliates. EPCO and its privately held subsidiaries depend on the cash distributions they receive from us (including Holdings prior to the Holdings Merger) and other investments to fund their other operations and to meet their debt obligations. The following table presents cash distributions received by EPCO and its privately held affiliates from us and Holdings for the periods presented:

	For the Six Months Ended June 30,	
	2011	2010
Enterprise	\$346.4	\$168.0
Holdings	--	116.1
Total distributions	\$346.4	\$284.1

Substantially all of the ownership interests in us that are owned or controlled by EPCO and its affiliates, other than those interests owned by 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 us.

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. We, 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.
- § 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 15 for additional information regarding our insurance programs.

Under the ASA, EPCO subleased to us (for \$1 per year) certain equipment it held pursuant to operating leases. EPCO was liable for the cash payments associated with these lease agreements. In June 2011, we paid \$5.4 million to purchase the assets from the lessor and the lease agreements were terminated. While these lease agreements were in effect, we recorded the full value of the lease payments made by EPCO on our behalf as a non-cash related party operating expense, with the offset to equity accounted for as a general contribution to our partnership.

Our operating costs and expenses include amounts paid to EPCO for the costs it incurs to operate our facilities, including the compensation of its employees. We reimburse EPCO for actual direct and indirect expenses it incurs

related to the operation of our assets. Likewise, our general and administrative costs include amounts paid to EPCO for administrative services, including the compensation of its 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

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services by each party (e.g., the allocation of legal or accounting salaries based on estimates of time spent on each entity's business and affairs). The following table presents a breakout of costs and expenses related to the ASA and other EPCO transactions for the periods presented:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
Operating costs and expenses	\$157.9	\$140.9	\$305.3	\$275.3
General and administrative expenses	34.5	24.6	60.1	49.1
Total costs and expenses	\$192.4	\$165.5	\$365.4	\$324.4

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

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

Relationships with Unconsolidated Affiliates

Many of our unconsolidated affiliates perform supporting or complementary roles to our other business operations. The following information summarizes significant related party transactions with our current unconsolidated affiliates:

- § We sell natural gas to Evangeline, which, in turn, uses the natural gas to satisfy supply commitments it has with a major Louisiana utility. Revenues from Evangeline were \$49.6 million and \$49.0 million for the three months ended June 30, 2011 and 2010, respectively. During the six months ended June 30, 2011 and 2010, revenues from Evangeline were \$80.3 million and \$86.8 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 \$3.2 million and \$3.1 million for the three months ended June 30, 2011 and 2010, respectively. During the six months ended June 30, 2011 and 2010, revenues from Promix were \$6.4 million and \$6.2 million, respectively. Expenses with Promix were \$8.7 million and \$7.5 million for the three months ended June 30, 2011 and 2010, respectively. During the six months ended June 30, 2011 and 2010, expenses with Promix were \$17.7 million and \$16.1 million, respectively.
- § We paid \$2.4 million and \$0.3 million to Centennial for other pipeline transportation services during the three months ended June 30, 2011 and 2010, respectively. During the six months ended June 30, 2011 and 2010, we paid Centennial \$2.6 million and \$2.9 million, respectively, for such services.
- § We paid \$0.3 million and \$1.6 million to Seaway for pipeline transportation and tank rentals in connection with our crude oil marketing activities during the three months ended June 30, 2011 and 2010, respectively. During the six months ended June 30, 2011 and 2010, we paid Seaway \$1.0 million and \$2.7 million, respectively, for such services.

§ We paid \$1.6 million and \$1.5 million to White River Hub primarily for firm capacity reservation fees during the three months ended June 30, 2011 and 2010, respectively. During the six months ended June 30, 2011 and 2010, we paid White River Hub \$3.3 million and \$2.9 million, respectively, of such fees.

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§ We perform management services for certain of our unconsolidated affiliates. We charged such affiliates \$3.2 million and \$2.8 million for the three months ended June 30, 2011 and 2010, respectively. During the six months ended June 30, 2011 and 2010, we charged affiliates \$6.4 million and \$5.7 million, respectively.

§ We have a long-term sales contract with a subsidiary of Energy Transfer Equity. In addition, we and another subsidiary of ETP transport natural gas on each other's systems and share operating expenses on certain pipelines. A subsidiary of ETP also sells natural gas to us. See previous table for related party revenue and expense amounts recorded by us in connection with Energy Transfer Equity.

In April 2011, we announced an intent to form a 50/50 joint venture with ETP to design and construct a proposed crude oil pipeline from Cushing, Oklahoma to Houston, Texas. The project would allow shippers greater access to the U.S. Gulf Coast-area refining complex from Cushing and add storage capacity at new facilities to be constructed and owned by the joint venture at our Houston crude oil terminal. Contingent upon receiving satisfactory shipper commitments, the proposed pipeline is projected to begin service in the fourth quarter of 2012. In May 2011, an open commitment period for shippers to contract for available capacity on the proposed pipeline was initiated. The commitment period has been extended to August 12, 2011.

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

At June 30, 2011, Duncan Energy Partners was owned 99.3% by its limited partners and 0.7% by its general partner, DEP GP, which is a wholly owned subsidiary of EPO. DEP GP is responsible for managing the business and operations of Duncan Energy Partners. DEP Operating Partnership L.P., a wholly owned subsidiary of Duncan Energy Partners, conducts substantially all of Duncan Energy Partners' business. At June 30, 2011, EPO beneficially owned 58.5% of Duncan Energy Partners' common units 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. See Note 1 for information regarding the proposed merger of Duncan Energy Partners with a subsidiary of Enterprise.

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 budgeted cost of the Haynesville Extension project is approximately \$1.5 billion (including capitalized interest), with Duncan Energy Partners' share currently estimated at \$990 million. In order to fund its capital spending 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.

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Note 13. Earnings Per Unit

The earnings per unit amounts included in these financial statements have been retroactively presented in connection with the unit-for-unit exchange that occurred under the Holdings Merger.

Basic and diluted earnings per unit amounts for periods prior to the Holdings Merger are based on net income attributable to partners, divided by the applicable weighted-average number of Holdings' units outstanding for the period adjusted for the merger exchange ratio of 1.5 Enterprise common units for each Holdings unit. For these periods, net income attributable to partners represents net income allocated to the former owners of Holdings, which was determined after amounts allocated to noncontrolling interest (which included net income allocated to Enterprise's limited partner interests that were owned by third parties and related parties other than Holdings).

Following the Holdings Merger, basic earnings per unit is computed by dividing net income attributable to our limited partner interests by the weighted-average number of our distribution-bearing units outstanding during a period (excluding the Designated Units).

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

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

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

	For the Three Months Ended June 30		For the Six Months Ended June 30,	
	2011	2010	2011	2010
BASIC EARNINGS PER UNIT				
Numerator:				
Net income attributable to partners	\$433.7	\$54.1	\$854.4	\$124.0
General partner interest in net income	--	*	--	*
Net income attributable to limited partners	\$433.7	\$54.1	\$854.4	\$124.0
Denominator:				
Common units	810.8	208.8	810.3	208.8
Time-vested restricted common units	4.3	--	4.2	--
Total	815.1	208.8	814.5	208.8
Basic earnings per unit:				
Net income attributable to partners	\$0.53	\$0.26	\$1.05	\$0.59
General partner interest in net income	--	*	--	*
Net income attributable to limited partners	\$0.53	\$0.26	\$1.05	\$0.59
DILUTED EARNINGS PER UNIT				
Numerator:				
Net income attributable to partners	\$433.7	\$54.1	\$854.4	\$124.0
General partner interest in net income	--	*	--	*
Net income attributable to limited partners	\$433.7	\$54.1	\$854.4	\$124.0
Denominator:				
Common units	810.8	208.8	810.3	208.8
Time-vested restricted common units	4.3	--	4.2	--
Class B units	4.5	--	4.5	--
Designated Units	30.6	--	30.6	--
Incremental option units	1.2	--	1.3	--
Total	851.4	208.8	850.9	208.8
Diluted earnings per unit:				
Net income attributable to partners	\$0.51	\$0.26	\$1.00	\$0.59
General partner interest in net income	--	*	--	*
Net income attributable to limited partners	\$0.51	\$0.26	\$1.00	\$0.59

* Amount is negligible

Note 14. Commitments and Contingencies

Litigation

As part of our normal business activities, we may be named as defendants in 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 fully indemnify us against losses arising from future legal proceedings.

Management has regular quarterly litigation reviews, including updates from legal counsel, to assess the possible need for accounting recognition or disclosure of these contingencies. We accrue an undiscounted liability for those contingencies where the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. We do not record a contingent liability when the likelihood of loss is probable but the amount cannot be reasonably estimated or when it is believed to be only reasonably possible or remote. For contingencies where an

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unfavorable outcome is reasonably possible and the impact would be material, we disclose the nature of the contingency and, where feasible, an estimate of the possible loss or range of loss. We will vigorously defend the partnership in litigation matters. Based on a consideration of all relevant known facts and circumstances (including insurance coverage), we do not believe the ultimate outcome of any currently pending lawsuit against us will have a material impact on our financial statements individually or in the aggregate. See Note 15 for information regarding our insurance program.

At June 30, 2011 and December 31, 2010, litigation accruals on an undiscounted basis of \$8.5 million and \$8.6 million, respectively, were recorded in our consolidated balance sheets as a component of other current liabilities. 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 accruals. In an effort to mitigate expenses associated with litigation, we may settle legal proceedings out of court.

Merger-Related Matters

We have completed a number of merger-related transactions in recent years that were material to our financial statements. Our proposed merger with Duncan Energy Partners is pending. The following discussion of litigation matters relates to these merger transactions. We do not believe that any expenditures related to such matters will be material to our financial statements. We will continue to vigorously defend the partnership in these matters.

Litigation Related to Holdings Acquisition of Ownership Interests in TEPPCO and TEPPCO GP. On February 14, 2008, Joel A. Gerber, then a purported unitholder of Holdings, filed a derivative complaint on behalf of Holdings 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. Holdings is named as a nominal defendant. The complaint alleges that the defendants, in breach of their fiduciary duties to Holdings and its unitholders, caused Holdings to purchase in May 2007 the TEPPCO GP membership interests and TEPPCO units from Mr. Duncan's affiliates at an unfair price. The complaint also alleges that Charles E. McMahan, Edwin E. Smith and Thurmon Andress, then constituting the three members of EPE Holdings' Audit, Conflicts and Governance ("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. On April 11, 2008, we filed a motion to dismiss this lawsuit with the Court of Chancery of the State of Delaware. In response to the motion to dismiss, on September 15, 2008, the plaintiff filed an amended complaint. On September 29, 2008, we filed a motion to dismiss the amended complaint with the Court of Chancery of the State of Delaware. The parties completed the briefing on the motion to dismiss on June 4, 2010. On February 8, 2011, the plaintiff filed a Motion for Leave to File a Second Amended and Supplemental Verified Complaint. On March 25, 2011, we filed a Brief in Opposition to Plaintiff's Motion for Leave to File a Second Amended and Supplemental Verified Complaint. See Note 12 for information regarding our relationship with EPCO and its affiliates.

Litigation Related to the TEPPCO Merger. On November 15, 2010, Joel A. Gerber filed a class action and derivative complaint in the Court of Chancery of the State of Delaware. The complaint asserts claims against Holdings, EPGP, EPCO and the then directors of EPE Holdings for breach of express and implied duties in connection with Holdings' sale of TEPPCO GP to us in October 2009 (the "2009 Sale Transaction") and the Holdings Merger in November 2010. The complaint also asserts claims against Mr. Duncan's estate, EPCO and us for tortious interference and unjust

enrichment in connection with the above transactions. The complaint alleges that Holdings sold TEPPCO GP to us in the 2009 Sale Transaction at an unfair price to Holdings and that the members of EPE Holdings' ACG Committee, which approved the 2009 Sale Transaction, were not independent because of their relationship with Mr. Duncan. The complaint also alleges that the terms of the Holdings Merger were unfair to Holdings' unitholders and that members of EPE Holdings' ACG committee, which approved the Holdings Merger, were not independent

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because of their relationship with Mr. Duncan. On December 13, 2010, we filed a motion to dismiss this lawsuit with the Court of Chancery of the State of Delaware. In response to the motion to dismiss, on March 18, 2011, the plaintiff filed an amended complaint. On April 1, 2011, we filed a motion to dismiss the amended complaint with the Court of Chancery of the State of Delaware.

Litigation Related to Holdings Merger. On September 9, 2010, Sanjay Israni, a purported unitholder of Holdings, filed a complaint in the Court of Chancery of the State of Delaware, as a putative class action on behalf of the unitholders of Holdings, 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. McMahan, Edwin E. Smith and B.W. Waycaster (the “Israni Complaint”). The Israni Complaint alleges, among other things, that we along with the named directors and EPCO have breached fiduciary duties in connection with the Holdings Merger (see Note 1) and that Holdings aided and abetted in these alleged breaches of fiduciary duties. On October 18, 2010, we filed a motion to dismiss this lawsuit with the Court of Chancery of the State of Delaware. On March 18, 2011, the plaintiffs filed a Stipulation and Proposed Order of Dismissal of all claims pending in that action without prejudice, with each party to bear its own costs and fees. The Court granted the Stipulation and Proposed Order of Dismissal on March 18, 2011.

On September 29, 2010, Eugene Lonergan, Sr., a purported unitholder of Holdings, filed a complaint in the Court of Chancery of the State of Delaware, as a putative class action on behalf of the unitholders of Holdings, 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. McMahan, 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 dealing, including failing to make adequate disclosures, in connection with the 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. On October 18, 2010, we filed a motion to dismiss this lawsuit with the Court of Chancery of the State of Delaware. On March 18, 2011, the plaintiffs filed a Stipulation and Proposed Order of Dismissal of all claims pending in that action without prejudice, with each party to bear its own costs and fees. The Court granted the Stipulation and Proposed Order of Dismissal on March 18, 2011.

Additionally, on September 23, 2010, Richard Fouke, a purported unitholder of Holdings, filed a complaint in the Court of Chancery of the State of Delaware, as a putative class action on behalf of the unitholders of Holdings, 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. McMahan, Edwin E. Smith and B.W. Waycaster (the “Fouke Complaint”). The Fouke Complaint alleges, among other things, that we, 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 Holdings Merger and that Holdings and the other defendants aided and abetted in the alleged breach. On October 18, 2010, we filed a motion to dismiss this lawsuit with the Court of Chancery of the State of Delaware. On July 12, 2011, the Court of Chancery entered stipulation and order of dismissal of the Fouke Complaint filed by the parties dismissing the claims without prejudice.

Litigation Related to the Duncan Merger. On March 8, 2011, Michael Crowley, a purported unitholder of Duncan Energy Partners, filed a complaint in the Court of Chancery of the State of Delaware, as a putative class action on behalf of the public unitholders of Duncan Energy Partners, captioned Michael Crowley v. Duncan Energy Partners L.P., DEP Holdings, LLC, W. Randall Fowler, Bryan F. Bulawa, William A. Bruckmann, III, Larry J. Casey, Richard S. Snell, Enterprise Products Partners L.P., Enterprise Products Holdings LLC, and Enterprise Products Operating

LLC (the “Crowley Complaint”). The Crowley Complaint alleges, among other things, that the named directors of DEP GP have breached fiduciary duties in connection with our proposal to acquire the outstanding publicly held common units of Duncan Energy Partners, that Duncan Energy Partners and DEP GP aided and abetted in these alleged breaches of fiduciary duties and that we, as the majority and controlling unitholder, along with EPO, have

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breached fiduciary duties by not acting in the minority unitholders' best interest to ensure the transaction resulting from our proposal is entirely fair.

On March 11, 2011, Sanjay Israni, a purported unitholder of Duncan Energy Partners, filed a complaint in the Court of Chancery of the State of Delaware, as a putative class action on behalf of the public unitholders of Duncan Energy Partners, captioned Sanjay Israni v. Duncan Energy Partners L.P., DEP Holdings, LLC, Enterprise Products Partners L.P., Enterprise Product Holdings LLC, Enterprise Production Operating LLC, W. Randall Fowler, Bryan F. Bulawa, William A. Bruckmann, III, Larry J. Casey, and Richard S. Snell (the "Israni Complaint II"). The Israni Complaint II alleges, among other things, that the named directors of DEP GP have breached fiduciary duties in connection with our proposal to acquire the outstanding publicly held common units of Duncan Energy Partners and that we, along with all of the other named defendants aided and abetted in these alleged breaches of fiduciary duties.

On March 28, 2011, Michael Rubin, a purported unitholder of Duncan Energy Partners, filed a complaint in the Court of Chancery of the State of Delaware, as a putative class action on behalf of the public unitholders of Duncan Energy Partners, captioned Michael Rubin v. Duncan Energy Partners L.P., DEP Holdings, LLC, W. Randall Fowler, Bryan F. Bulawa, William A. Bruckmann, III, Larry J. Casey, Richard S. Snell, Enterprise Products Partners L.P., Enterprise Products Holdings LLC, and Enterprise Products Operating LLC (the "Rubin Complaint"). The Rubin Complaint alleges, among other things, that the named directors of DEP GP have breached fiduciary duties in connection with our proposal to acquire the outstanding publicly held common units of Duncan Energy Partners, that Duncan Energy Partners and DEP GP aided and abetted in these alleged breaches of fiduciary duties and that we, as the majority and controlling unitholder, along with EPO, have breached fiduciary duties by not acting in the best interests of the minority unitholders to ensure the transaction resulting from our proposal is entirely fair.

On April 5, 2011, the plaintiffs in the Crowley Complaint, the Israni Complaint II, and the Rubin Complaint filed a Proposed Order of Consolidation and Appointment of Lead Counsel in the Court of Chancery of the State of Delaware. The court granted that order on the same day consolidating the three actions into a single consolidated action, captioned In re Duncan Energy Partners L.P. Unitholders Litigation. On June 3, 2011 the Delaware plaintiffs filed a consolidated amended complaint which alleges, among other things, breach of express and implied contractual duties contained in Duncan Energy Partners' partnership agreement by DEP GP and the named directors of DEP GP and that all defendants have aided and abetted these alleged breaches. The consolidated amended complaint also alleges that the defendants failed to provide full and fair disclosures regarding the proposed transaction.

On March 7, 2011, Merle Davis, a purported unitholder of Duncan Energy Partners, filed a petition in the 269th District Court of Harris County, Texas, as a putative class action on behalf of the unitholders of Duncan Energy Partners, captioned Merle Davis, on Behalf of Himself and All Others Similarly Situated v. Duncan Energy Partners L.P., W. Randall Fowler, Bryan F. Bulawa, William A. Bruckmann, III, Larry J. Casey, Richard S. Snell, DEP Holdings, LLC, and Enterprise Products Partners L.P. (the "Davis Petition"). The Davis Petition alleges, among other things, that we and the named directors of DEP GP have breached fiduciary duties in connection with our proposal to acquire the outstanding publicly held common units of Duncan Energy Partners and that we and Duncan Energy Partners aided and abetted in these alleged breaches of fiduciary duties.

On March 9, 2011, Donald Weilersbacher, a purported unitholder of Duncan Energy Partners, filed a petition in the 334th District Court of Harris County, Texas, as a putative class action on behalf of the unitholders of Duncan Energy Partners, captioned Donald Weilersbacher, on Behalf of Himself and All Others Similarly Situated v. Duncan Energy Partners L.P., Enterprise Products Partners L.P., DEP Holdings, LLC, W. Randall Fowler, Bryan F. Bulawa, William A. Bruckmann, III, Larry J. Casey, and Richard S. Snell (the "Weilersbacher Petition"). The Weilersbacher Petition alleges, among other things, that the named directors of DEP GP have breached fiduciary duties in connection with

our proposal to acquire the outstanding publicly held common units of Duncan Energy Partners and that we aided and abetted in these alleged breaches of fiduciary duties.

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On March 17, 2011, the plaintiffs in the Davis Petition and the Weilersbacher Petition filed a motion and proposed Order for Consolidation of Related Actions, Appointment of Interim Co-Lead Counsel, and Order Compelling Limited Expedited Discovery. Plaintiffs and defendants subsequently agreed to postpone discovery until after the plaintiffs file a consolidated petition. On March 28, 2011, the plaintiffs filed an amended motion and proposed Order for Consolidation of Related Actions and Appointment of Interim Co-Lead Counsel. On May 4, 2011, the court entered an order consolidating the cases and appointing interim lead counsel. On May 11, 2011, plaintiffs filed their consolidated petition. On June 23, 2011, the plaintiffs filed a Notice of Nonsuit Without Prejudice and the cases were dismissed without prejudice.

On July 5, 2011, Merle Davis and Donald Weilersbacher, purported unitholders of Duncan Energy Partners, filed a complaint in the United States District Court of the Southern District of Texas, Houston Division, as a putative class action on behalf of the unitholders of Duncan Energy Partners, captioned Merle Davis and Donald Weilersbacher, on Behalf of Themselves and All Others Similarly Situated vs. Duncan Energy Partners, L.P., W. Randall Fowler, Bryan F. Bulawa, William A. Bruckmann, III, Larry J. Casey, Richard Snell, DEP Holdings, LLC, and Enterprise Products Partners L.P. (the “Davis/Weilersbacher Federal Complaint”). The Davis/Weilersbacher Federal Complaint alleged, among other things, that Duncan Energy Partners, DEP GP and the named directors of DEP GP breached express and implied contractual duties in connection with our proposal to acquire Duncan Energy Partners’ outstanding publicly held common units, that all defendants aided and abetted in these alleged breaches, and that we and Duncan Energy Partners violated Section 14(a) and Section 20(a) of the Exchange Act.

On August 3, 2011, John Rinker and Arthur H. Speier, purported unitholders of Duncan Energy Partners, filed a complaint in the United States District Court of the Southern District of Texas, Houston Division, as a putative class action on behalf of the unitholders of Duncan Energy Partners, captioned John Rinker and Arthur H. Speier, on Behalf of Themselves and All Others Similarly Situated v. Duncan Energy Partners L.P., DEP Holdings, LLC, W. Randall Fowler, Bryan F. Bulawa, William A. Bruckmann, III, Larry J. Casey, Richard S. Snell and Enterprise Products Partners L.P. The Rinker/Speier complaint alleges, among other things, that Duncan Energy Partners, DEP GP and the named directors of DEP GP breached express and implied contractual duties in connection with our proposal to acquire Duncan Energy Partners’ outstanding publicly held common units, that all defendants aided and abetted in these alleged breaches, and that we and Duncan Energy Partners violated Section 14(a) and Section 20(a) of the Exchange Act.

Environmental-Related Matters

On occasion, we are assessed monetary sanctions by governmental authorities related to administrative or judicial proceedings involving environmental matters. The following is a discussion of such matters where the amount of monetary sanctions sought is in excess of \$0.1 million. We do not believe that any expenditures related to such matters will be material to our financial statements.

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.

On April 23, 2010, the West Red Line of MAPL ruptured as a result of historical external, mechanical damage to the pipeline releasing 1,669 barrels of natural gasoline. 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 do not believe that any potential payment we make in connection with these releases will have a material impact on our consolidated financial position, results of operations or cash flows.

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Redelivery Commitments

We store natural gas, NGLs and petrochemicals under various agreements that are owned by third parties. Under the terms of these agreements, we are generally required to redeliver volumes to the owner on demand. At June 30, 2011, we had approximately 23.4 MMBbls of NGL and petrochemical products and 14.3 trillion British thermal units of natural gas in our custody that were owned by third parties. We maintain insurance coverage related to such volumes that we believe is consistent with our exposure. See Note 15 for information regarding insurance matters.

Regulatory Matters

Responding to scientific reports regarding threats posed by global warming, the U.S. Congress has considered legislation to reduce emissions of greenhouse gases. In addition, some states, including states in which our facilities or operations are located such as California and New Mexico, have individually or in regional cooperation, imposed restrictions on greenhouse gas emissions under various policies and approaches, including establishing a cap on emissions, requiring efficiency measures, or providing incentives for pollution reduction, use of renewable energy, or use of fuels with lower carbon content.

The U.S. Environmental Protection Agency ("EPA") has taken action under the federal Clean Air Act ("CAA") to regulate greenhouse gas emissions. In November 2010, the EPA finalized rules expanding its Mandatory Greenhouse Gas Reporting Rule, originally promulgated in October 2009, to be applicable to the oil and natural gas industry, including certain onshore oil and natural gas production activities, which may affect certain of our existing or future operations and require the inventory and reporting of emissions. In addition, the EPA has taken the position that existing CAA provisions require an assessment of greenhouse gas emissions within the permitting process for certain large new or modified stationary sources under the EPA's Prevention of Significant Deterioration and Title V permit programs beginning in 2011. Facilities triggering permit requirements may be required to reduce greenhouse gas emissions consistent with "best available control technology" standards if deemed to be cost-effective.

These or other federal, regional and state measures could increase the operating and compliance costs of our pipelines, natural gas processing plants, fractionation plants and other facilities, and could by affecting the price of, or reducing the demand for, fossil fuels or providing competitive advantages to competing fuels and energy sources, adversely affect market demand or pricing for our products or products served by our midstream infrastructure. In addition, there have been several court cases implicating greenhouse gas emissions and climate change issues that could establish precedent that may indirectly affect our business, customers or the energy sector generally.

Any of these climate change legislative or judicial initiatives or developments could have a material impact on our financial statements; however, we are unable to provide a range of estimated future costs due to the extreme uncertainty of such matters. There is considerable public and private debate over global warming and the environmental effects of greenhouse gas emissions.

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 AA and BB in January 2011 and (iii) the repayment of Senior Notes B in February 2011, there have been no significant changes in our consolidated debt obligations since those reported in our 2010 Form 10-K. See Note 9 for additional information regarding our consolidated debt obligations.

Operating Lease Obligations

Lease and rental expense included in costs and expenses was \$21.5 million and \$15.9 million during the three months ended June 30, 2011 and 2010, respectively. For the six months ended June 30,

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2011 and 2010, lease and rental expense was \$42.0 million and \$32.3 million, respectively. There have been no material changes in our operating lease commitments since those reported in our 2010 Form 10-K.

Purchase Obligations

There have been no material changes in our consolidated purchase obligations since those reported in our 2010 Form 10-K.

Other Claims

As part of our normal business activities with joint venture partners and certain customers and suppliers, we occasionally make claims against such parties or have claims made against us as a result of disputes related to contractual agreements or similar arrangements. As of June 30, 2011, our contingent claims against such parties were approximately \$109.2 million and claims against us were approximately \$100.9 million. These matters are in various stages of assessment and the ultimate outcome of such disputes cannot be reasonably estimated at this time; however, in our opinion, the likelihood of a material impact on our consolidated financial statements from such disputes is remote. Accordingly, accruals for loss contingencies related to these matters have not been reflected in our consolidated financial statements.

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 \$53.2 million in the event of a default by Centennial. As of June 30, 2011, we have a recorded liability of \$7.5 million representing the estimated fair value of our share of the Centennial debt guaranty.

In lieu of Centennial procuring insurance to satisfy third-party claims arising from a catastrophic event, we and Centennial's other joint venture partner have entered a limited cash call agreement. We are obligated to contribute up to a maximum of \$50.0 million (in proportion to our 50% ownership interest in Centennial) in the event of a catastrophic event. At June 30, 2011, we have a recorded liability of \$3.2 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 15. Significant Risks and Uncertainties

Insurance Matters

We participate as a named insured in EPCO's insurance program, which provides us with property damage, business interruption and other insurance 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 may not fully cover every type of damage, interruption or other loss that might occur. If we were to incur a significant loss for which we were not fully insured, it could have a material impact on our financial position, results of operations and cash flows. In addition, there may be a timing difference between amounts we are required to pay in connection with a loss and amounts we receive from insurance as reimbursement. Any event that materially interrupts the revenues generated by our consolidated operations, or other losses that require us to make material

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.

From a financial accounting perspective, we expense losses up to our deductible amount, which can range from \$5.0 million to \$75.0 million depending on the nature of the loss (windstorm or non-windstorm) and the assets involved (onshore or offshore). With respect to property damage insurance claims in excess of our deductible, we record a claim receivable from our insurers for our actual costs to

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

repair the asset (or the carrying value of damaged assets we elect not to repair) when the recovery of such amounts is probable. To the extent that any of our property damage claims are later judged not recoverable, such amounts are expensed. If property damage insurance proceeds exceed our claim receivable, such excess amount is recognized as income (a gain) when either the non-refundable cash is received or we have a binding settlement agreement with a carrier that clearly states that the payment will be made.

We received cash proceeds of \$12.0 million and \$41.0 million, respectively, related to property damage claims during the three and six months ended June 30, 2010. Operating income and gross operating margin for the three and six months ended June 30, 2010 include \$10.3 million and \$18.2 million, respectively, of related gains.

With respect to business interruption insurance claims, we recognize income only when we receive non-refundable cash proceeds from insurers. For the six months ended June 30, 2010, we recognized \$1.1 million of such gains, which are a component of operating income and gross operating margin.

February 2011 West Storage Incident. On February 8, 2011, we experienced an NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility. West Storage consists of ten underground salt dome storage caverns with a storage capacity of approximately 15 MMBbls. Through the reconfiguration of product receipt and delivery capabilities and other measures, we have returned our Mont Belvieu plants and related assets to close to the same capabilities as we had prior to the incident; however, our West Storage location and associated underground storage wells remain partially inoperative at this time. Remaining repairs to this location are underway and are expected to be completed in stages by early 2012. Our insurance deductible for such property damage events was \$5.0 million, which expense was recognized in the first quarter of 2011. Based on current information, we estimate that the total cost related to this incident will approximate \$150 million. At June 30, 2011, we had \$44.8 million of estimated property damage insurance claims outstanding, including \$37.3 million associated with the fire at West Storage.

Note 16. Supplemental Cash Flow Information

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

	For the Six Months Ended June 30,	
	2011	2010
Decrease (increase) in:		
Accounts receivable – trade	\$(474.2)	\$184.5
Accounts receivable – related parties	(0.2)	9.9
Inventories	266.5	(326.4)
Prepaid and other current assets	(55.8)	(113.1)
Other assets	(34.2)	14.0
Increase (decrease) in:		
Accounts payable – trade	110.9	68.4
Accounts payable – related parties	49.9	67.5
Accrued product payables	479.0	(271.8)
Accrued interest	18.1	8.7
Other current liabilities	(10.4)	28.6

Other liabilities	11.8	(6.2)
Net effect of changes in operating accounts	\$361.4	\$(335.9)

We incurred liabilities for construction in progress that had not been paid at June 30, 2011 and December 31, 2010 of \$246.4 million and \$201.6 million, respectively. Such amounts are not included under the caption “Capital expenditures” on the Unaudited Condensed Statements of Consolidated Cash Flows.

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

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.

Proceeds from asset sales and related transactions increased \$226.4 million period-to-period, primarily from the sale of 4.45 million Energy Transfer Equity common units in May 2011 and certain non-strategic marine assets and NGL fractionation facilities during the first quarter of 2011.

See Note 10 for information regarding cash amounts attributable to noncontrolling interest.

See Note 15 for information regarding cash proceeds from insurance claims.

Note 17. Condensed Consolidating Financial Information

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

EPO has issued publicly traded debt securities. Enterprise Products Partners L.P., as the parent company of EPO, guarantees the debt obligations of EPO, with the exception of Duncan Energy Partners' debt obligations and the remaining debt obligations of TEPPCO. If EPO were to default on any of its guaranteed debt, Enterprise Products Partners L.P. would be responsible for full repayment of that obligation. EPO's consolidated subsidiaries have no significant restrictions on their ability to pay distributions or make loans to Enterprise Products Partners L.P. See Note 9 for additional information regarding our consolidated debt obligations.

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

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Balance Sheet
June 30, 2011

	Subsidiary Issuer (EPO)	EPO and Subsidiaries Other Subsidiaries (Non- guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
ASSETS							
Current assets:							
Cash and cash equivalents and restricted cash	\$ 198.8	\$ 60.1	\$ (33.3)	\$ 225.6	\$ --	\$ (0.3)	\$ 225.3
Accounts receivable – trade, net	1,647.9	2,676.2	(49.8)	4,274.3	--	--	4,274.3
Accounts receivable – related parties	(1,381.8)	1,345.4	79.6	43.2	(5.5)	--	37.7
Prepaid and other current assets	1,041.3	378.4	(18.9)	1,400.8	0.4	--	1,401.2
Total current assets	1,506.2	4,460.1	(22.4)	5,943.9	(5.1)	(0.3)	5,938.5
Property, plant and equipment, net	1,490.9	19,317.8	(9.8)	20,798.9	--	--	20,798.9
Investments in unconsolidated affiliates	23,540.1	6,248.0	(27,702.2)	2,085.9	11,259.6	(11,259.6)	2,085.9
Intangible assets, net	148.9	1,621.8	(14.1)	1,756.6	--	--	1,756.6
Goodwill	454.3	1,652.8	--	2,107.1	--	--	2,107.1
Other assets	255.2	162.9	(126.7)	291.4	--	--	291.4
Total assets	\$ 27,395.6	\$ 33,463.4	\$ (27,875.2)	\$ 32,983.8	\$ 11,254.5	\$ (11,259.9)	\$ 32,978.4
LIABILITIES AND EQUITY							
Current liabilities:							
Current maturities of debt	\$ 490.5	\$ 291.8	\$ --	\$ 782.3	\$ --	\$ --	\$ 782.3
Accounts payable – trade	252.9	550.7	(33.3)	770.3	0.3	(0.3)	770.3
Accounts payable – related parties	--	225.5	(42.3)	183.2	--	--	183.2
Accrued product payables	2,143.9	2,693.0	(50.9)	4,786.0	--	--	4,786.0
Accrued interest	269.1	2.1	(0.2)	271.0	--	--	271.0
Other current liabilities	218.4	359.6	(12.2)	565.8	--	0.2	566.0
	3,374.8	4,122.7	(138.9)	7,358.6	0.3	(0.1)	7,358.8

Total current liabilities							
Long-term debt	12,575.2	978.4	(8.9)	13,544.7	--	--	13,544.7
Other long-term liabilities	26.5	274.4	(0.4)	300.5	--	(0.9)	299.6
Commitments and contingencies							
Equity:							
Partners' and other owners' equity	11,419.1	23,852.5	(24,027.3)	11,244.3	11,254.2	(11,244.3)	11,254.2
Noncontrolling interest	--	4,235.4	(3,699.7)	535.7	--	(14.6)	521.1
Total equity	11,419.1	28,087.9	(27,727.0)	11,780.0	11,254.2	(11,258.9)	11,775.3
Total liabilities and equity	\$ 27,395.6	\$ 33,463.4	\$ (27,875.2)	\$ 32,983.8	\$ 11,254.5	\$ (11,259.9)	\$ 32,978.4

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

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

	Subsidiary Issuer (EPO)	EPO and Subsidiaries Other Subsidiaries (Non- guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
ASSETS							
Current assets:							
Cash and cash equivalents and restricted cash	\$ 97.1	\$ 70.0	\$ (2.9)	\$ 164.2	\$ --	\$ --	\$ 164.2
Accounts receivable – trade, net	1,684.1	2,127.9	(11.9)	3,800.1	--	--	3,800.1
Accounts receivable – related parties	(952.7)	927.6	63.2	38.1	(1.3)	--	36.8
Prepaid and other current assets	1,030.7	486.2	(10.9)	1,506.0	--	--	1,506.0
Total current assets	1,859.2	3,611.7	37.5	5,508.4	(1.3)	--	5,507.1
Property, plant and equipment, net	1,461.0	17,881.9	(10.0)	19,332.9	--	--	19,332.9
Investments in unconsolidated affiliates	22,640.3	6,254.0	(26,601.2)	2,293.1	11,375.5	(11,375.5)	2,293.1
Intangible assets, net	155.5	1,700.8	(14.6)	1,841.7	--	--	1,841.7
Goodwill	469.1	1,638.6	--	2,107.7	--	--	2,107.7
Other assets	296.4	126.7	(144.8)	278.3	--	--	278.3
Total assets	\$ 26,881.5	\$ 31,213.7	\$ (26,733.1)	\$ 31,362.1	\$ 11,374.2	\$ (11,375.5)	\$ 31,360.8
LIABILITIES AND EQUITY							
Current liabilities:							
Current maturities of debt	\$ --	\$ 282.3	\$ --	\$ 282.3	\$ --	\$ --	\$ 282.3
Accounts payable – trade	138.1	406.8	(2.9)	542.0	--	--	542.0
Accounts payable – related parties	--	204.3	(71.2)	133.1	--	--	133.1
Accrued product payables	2,057.2	2,124.8	(17.2)	4,164.8	--	--	4,164.8
Accrued interest	251.3	1.8	(0.2)	252.9	--	--	252.9
Other current liabilities	217.2	294.7	(6.9)	505.0	--	0.1	505.1
	2,663.8	3,314.7	(98.4)	5,880.1	--	0.1	5,880.2

Total current liabilities							
Long-term debt	12,663.7	626.4	(8.9)	13,281.2	--	--	13,281.2
Other long-term liabilities							
	48.0	251.5	(0.1)	299.4	--	(0.8)	298.6
Commitments and contingencies							
Equity:							
Partners' and other owners' equity							
	11,506.0	23,176.8	(23,321.2)	11,361.6	11,374.2	(11,361.6)	11,374.2
Noncontrolling interest							
	--	3,844.3	(3,304.5)	539.8	--	(13.2)	526.6
Total equity	11,506.0	27,021.1	(26,625.7)	11,901.4	11,374.2	(11,374.8)	11,900.8
Total liabilities and equity	\$ 26,881.5	\$ 31,213.7	\$ (26,733.1)	\$ 31,362.1	\$ 11,374.2	\$ (11,375.5)	\$ 31,360.8

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

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
Three Months Ended June 30, 2011

	EPO and Subsidiaries			Enterprise Products Partners L.P.			
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Revenues	\$ 7,959.5	\$ 7,194.7	\$ (3,937.7)	\$ 11,216.5	\$ --	\$ --	\$ 11,216.5
Costs and expenses:							
Operating costs and expenses	7,824.2	6,646.7	(3,937.6)	10,533.3	--	--	10,533.3
General and administrative costs	3.4	43.8	--	47.2	3.2	--	50.4
Total costs and expenses	7,827.6	6,690.5	(3,937.6)	10,580.5	3.2	--	10,583.7
Equity in income of unconsolidated affiliates	492.8	24.9	(506.6)	11.1	436.9	(436.9)	11.1
Operating income	624.7	529.1	(506.7)	647.1	433.7	(436.9)	643.9
Other income (expense):							
Interest expense	(184.0)	(6.2)	1.9	(188.3)	--	--	(188.3)
Other, net	1.9	0.3	(1.9)	0.3	--	--	0.3
Total other expense, net	(182.1)	(5.9)	--	(188.0)	--	--	(188.0)
Income before provision for income taxes	442.6	523.2	(506.7)	459.1	433.7	(436.9)	455.9
Provision for income taxes	(5.7)	(1.6)	--	(7.3)	--	(0.1)	(7.4)
Net income	436.9	521.6	(506.7)	451.8	433.7	(437.0)	448.5
Net loss (income) attributable to noncontrolling interest	--	(7.5)	(7.5)	(15.0)	--	0.2	(14.8)
Net income attributable to entity	\$ 436.9	\$ 514.1	\$ (514.2)	\$ 436.8	\$ 433.7	\$ (436.8)	\$ 433.7

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

	EPO and Subsidiaries			Enterprise Holdings			
	Subsidiary	Other	EPO and Subsidiaries	Consolidated	Eliminations	Consolidated	

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	Issuer (EPO)	Subsidiaries (Non-guarantor)	Subsidiaries Eliminations and Adjustments	EPO and Subsidiaries	Products Partners L.P. (Guarantor)	and EPGP	and Adjustments	Total
Revenues	\$ 5,658.5	\$ 4,787.3	\$ (2,902.4)	\$ 7,543.4	\$ --	\$ --	\$ --	\$ 7,543.4
Costs and expenses:								
Operating costs and expenses	5,550.4	4,325.8	(2,902.0)	6,974.2	--	--	--	6,974.2
General and administrative costs	2.9	32.8	--	35.7	2.2	2.6	--	40.5
Total costs and expenses	5,553.3	4,358.6	(2,902.0)	7,009.9	2.2	2.6	--	7,014.7
Equity in income of unconsolidated affiliates	419.3	42.4	(445.0)	16.7	359.4	130.1	(495.2)	11.0
Operating income	524.5	471.1	(445.4)	550.2	357.2	127.5	(495.2)	539.7
Other income (expense):								
Interest expense	(164.1)	(7.0)	2.5	(168.6)	--	(10.6)	--	(179.2)
Other, net	2.6	0.3	(2.5)	0.4	--	--	--	0.4
Total other expense, net	(161.5)	(6.7)	--	(168.2)	--	(10.6)	--	(178.8)
Income before provision for income taxes	363.0	464.4	(445.4)	382.0	357.2	116.9	(495.2)	360.9
Provision for income taxes	(3.4)	(3.1)	--	(6.5)	--	--	--	(6.5)
Net income	359.6	461.3	(445.4)	375.5	357.2	116.9	(495.2)	354.4
Net loss (income) attributable to noncontrolling interest	--	6.4	(22.7)	(16.3)	--	--	(284.0)	(300.3)
Net income attributable to entity	\$ 359.6	\$ 467.7	\$ (468.1)	\$ 359.2	\$ 357.2	\$ 116.9	\$ (779.2)	\$ 54.1

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

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
Six Months Ended June 30, 2011

	EPO and Subsidiaries			Enterprise Products Partners L.P.			
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Revenues	\$ 16,284.3	\$ 13,273.4	\$ (8,157.5)	\$ 21,400.2	\$ --	\$ --	\$ 21,400.2
Costs and expenses:							
Operating costs and expenses	16,002.4	12,225.3	(8,157.3)	20,070.4	--	--	20,070.4
General and administrative costs	4.3	77.5	--	81.8	6.5	--	88.3
Total costs and expenses	16,006.7	12,302.8	(8,157.3)	20,152.2	6.5	--	20,158.7
Equity in income of unconsolidated affiliates	950.8	56.7	(980.2)	27.3	860.9	(860.9)	27.3
Operating income	1,228.4	1,027.3	(980.4)	1,275.3	854.4	(860.9)	1,268.8
Other income (expense):							
Interest expense	(363.0)	(12.9)	3.8	(372.1)	--	--	(372.1)
Other, net	3.9	0.7	(3.8)	0.8	--	--	0.8
Total other expense, net	(359.1)	(12.2)	--	(371.3)	--	--	(371.3)
Income before provision for income taxes	869.3	1,015.1	(980.4)	904.0	854.4	(860.9)	897.5
Provision for income taxes	(8.5)	(5.9)	--	(14.4)	--	(0.1)	(14.5)
Net income	860.8	1,009.2	(980.4)	889.6	854.4	(861.0)	883.0
Net loss (income) attributable to noncontrolling interest	--	(10.9)	(18.2)	(29.1)	--	0.5	(28.6)
Net income attributable to entity	\$ 860.8	\$ 998.3	\$ (998.6)	\$ 860.5	\$ 854.4	\$ (860.5)	\$ 854.4

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

	EPO and Subsidiaries			Enterprise Holdings			
	Subsidiary	Other	EPO and Subsidiaries	Consolidated	Eliminations	Consolidated	

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	Issuer (EPO)	Subsidiaries (Non-guarantor)	Subsidiaries Eliminations and Adjustments	EPO and Subsidiaries	Products Partners L.P. (Guarantor)	and EPGP	and Adjustments	Total
Revenues	\$ 12,615.9	\$ 9,400.3	\$ (5,928.3)	\$ 16,087.9	\$ --	\$ --	\$ --	\$ 16,087.9
Costs and expenses:								
Operating costs and expenses	12,396.5	8,478.1	(5,928.5)	14,946.1	--	--	--	14,946.1
General and administrative costs	2.9	68.4	--	71.3	4.2	5.3	--	80.8
Total costs and expenses	12,399.4	8,546.5	(5,928.5)	15,017.4	4.2	5.3	--	15,026.9
Equity in income of unconsolidated affiliates	833.0	95.9	(896.2)	32.7	739.2	272.1	(1,006.4)	37.6
Operating income	1,049.5	949.7	(896.0)	1,103.2	735.0	266.8	(1,006.4)	1,098.6
Other income (expense):								
Interest expense	(307.9)	(14.4)	5.1	(317.2)	--	(19.9)	--	(337.1)
Other, net	5.4	0.2	(5.1)	0.5	--	--	--	0.5
Total other expense, net	(302.5)	(14.2)	--	(316.7)	--	(19.9)	--	(336.6)
Income before provision for income taxes	747.0	935.5	(896.0)	786.5	735.0	246.9	(1,006.4)	762.0
Provision for income taxes	(8.3)	(6.9)	--	(15.2)	--	--	--	(15.2)
Net income	738.7	928.6	(896.0)	771.3	735.0	246.9	(1,006.4)	746.8
Net loss (income) attributable to noncontrolling interest	--	6.6	(39.0)	(32.4)	--	--	(590.4)	(622.8)
Net income attributable to entity	\$ 738.7	\$ 935.2	\$ (935.0)	\$ 738.9	\$ 735.0	\$ 246.9	\$ (1,596.8)	\$ 124.0

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

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Cash Flows
Six Months Ended June 30, 2011

	Subsidiary Issuer (EPO)	EPO and Subsidiaries Other Subsidiaries (Non- guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Operating activities:							
Net income	\$ 860.8	\$ 1,009.2	\$ (980.4)	\$ 889.6	\$ 854.4	\$ (861.0)	\$ 883.0
Adjustments to reconcile net income to cash provided by operating activities:							
Depreciation, amortization and accretion	56.6	428.9	(0.7)	484.8	--	--	484.8
Equity in income of unconsolidated affiliates	(950.8)	(56.7)	980.2	(27.3)	(860.9)	860.9	(27.3)
Distributions received from unconsolidated affiliates	115.3	111.9	(142.4)	84.8	979.8	(979.8)	84.8
Net effect of changes in operating accounts and other operating activities	1,076.0	(383.2)	(365.1)	327.7	1.5	--	329.2
Cash provided by operating activities	1,157.9	1,110.1	(508.4)	1,759.6	974.8	(979.9)	1,754.5
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(50.6)	(1,659.2)	--	(1,709.8)	--	--	(1,709.8)
Other investing activities	(466.5)	231.9	452.2	217.6	(49.2)	49.2	217.6
Cash used in investing activities	(517.1)	(1,427.3)	452.2	(1,492.2)	(49.2)	49.2	(1,492.2)
Financing activities:							
Borrowings under debt agreements	3,372.1	419.0	--	3,791.1	--	--	3,791.1
Repayments of debt	(2,976.0)	(57.5)	--	(3,033.5)	--	--	(3,033.5)
Cash distributions paid to partners	(979.8)	(440.0)	440.0	(979.8)	(966.5)	979.8	(966.5)
	--	(72.8)	38.0	(34.8)	--	--	(34.8)

Cash distributions paid
to noncontrolling
interest

Cash contributions from noncontrolling interest	--	449.4	(446.6)	2.8	--	(0.2)	2.6
Net cash proceeds from issuance of common units	--	--	--	--	45.1	--	45.1
Cash contributions from members	49.2	5.6	(5.6)	49.2	--	(49.2)	--
Other financing activities	(18.5)	--	--	(18.5)	(4.2)	--	(22.7)
Cash provided by (used in) financing activities	(553.0)	303.7	25.8	(223.5)	(925.6)	930.4	(218.7)
Net change in cash and cash equivalents	87.8	(13.5)	(30.4)	43.9	--	(0.3)	43.6
Cash and cash equivalents, January 1	0.5	67.9	(2.9)	65.5	--	--	65.5
Cash and cash equivalents, June 30	\$ 88.3	\$ 54.4	\$ (33.3)	\$ 109.4	\$ --	\$ (0.3)	\$ 109.1

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

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

	EPO and Subsidiaries			Enterprise Products		Holdings		Eliminations	
	Subsidiary	Other	EPO and	Consolidated	Partners	and	and	and	Consolidated
	Issuer	Subsidiaries	Eliminations	EPO and	L.P.	EPGP	Adjustments	Adjustments	Total
	(EPO)	(Non-guarantor)	Adjustments	Subsidiaries	(Guarantor)				
Operating activities:									
Net income	\$ 738.7	\$ 928.6	\$ (896.0)	\$ 771.3	\$ 735.0	\$ 246.9	\$ (1,006.4)		\$ 746.8
Adjustments to reconcile net income to cash provided by operating activities:									
Depreciation, amortization and accretion	45.7	406.4	(0.7)	451.4	--	2.1	--		453.5
Equity in income of unconsolidated affiliates	(833.0)	(95.9)	896.2	(32.7)	(739.2)	(272.1)	1,006.4		(37.6)
Distributions received from unconsolidated affiliates	88.0	85.4	(114.6)	58.8	838.7	317.0	(1,113.2)		101.3
Net effect of changes in operating accounts and other operating activities	384.9	(870.9)	140.5	(345.5)	1.4	0.6	(0.1)		(343.6)
Cash provided by operating activities	424.3	453.6	25.4	903.3	835.9	294.5	(1,113.3)		920.4
Investing activities:									
Capital expenditures, net of contributions in aid of construction costs	63.2	(801.3)	--	(738.1)	--	--	--		(738.1)
Cash used for business combinations	(2.2)	(1,218.0)	--	(1,220.2)	--	--	--		(1,220.2)
	(1,440.1)	59.0	1,447.6	66.5	(988.9)	(51.5)	1,040.4		66.5

Other investing activities								
Cash used in investing activities	(1,379.1)	(1,960.3)	1,447.6	(1,891.8)	(988.9)	(51.5)	1,040.4	(1,891.8)
Financing activities:								
Borrowings under debt agreements	3,435.7	103.1	--	3,538.8	--	55.1	--	3,593.9
Repayments of debt	(2,191.9)	(23.1)	--	(2,215.0)	--	(41.7)	--	(2,256.7)
Cash distributions paid to partners	(838.7)	(109.7)	109.7	(838.7)	(830.9)	(274.9)	1,794.9	(149.6)
Cash distributions paid to noncontrolling interest	--	(52.5)	15.9	(36.6)	--	--	(683.9)	(720.5)
Cash contributions from noncontrolling interest	--	213.2	(211.3)	1.9	--	--	960.0	961.9
Net cash proceeds from issuance of common units	--	--	--	--	990.1	--	(990.1)	--
Cash contributions from members	988.9	1,387.6	(1,387.6)	988.9	--	19.8	(1,008.7)	--
Other financing activities	(13.5)	--	--	(13.5)	(3.6)	--	0.6	(16.5)
Cash provided by (used in) financing activities	1,380.5	1,518.6	(1,473.3)	1,425.8	155.6	(241.7)	72.8	1,412.5
Effect of exchange rate changes on cash	--	0.1	--	0.1	--	--	--	0.1
Net change in cash and cash equivalents	425.7	11.9	(0.3)	437.3	2.6	1.3	(0.1)	441.1
Cash and cash equivalents, January 1	14.4	46.3	(6.2)	54.5	--	0.7	0.1	55.3
Cash and cash equivalents, June 30	\$ 440.1	\$ 58.3	\$ (6.5)	\$ 491.9	\$ 2.6	\$ 2.0	\$ --	\$ 496.5

Note 18. Subsequent Event

Sale of Energy Transfer Equity Common Units

In July 2011, we sold an additional 4,114,136 Energy Transfer Equity common units in two separate transactions for a combined \$167.7 million. Proceeds from these transactions were used for general partnership purposes, including funding of capital expenditures. Following the July transactions, we own 30,411,954 Energy Transfer Equity common units representing approximately 13.6% of their common units outstanding.

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

For the three and six months ended June 30, 2011 and 2010.

The following information should be read in conjunction with our unaudited condensed consolidated financial statements and accompanying notes included in this quarterly report on Form 10-Q. The following information and such unaudited condensed consolidated financial statements should also be read in conjunction with the audited financial statements and related notes, together with our discussion and analysis of financial position and results of operations, included in our annual report on Form 10-K for the year ended December 31, 2010, as filed on March 1, 2011 (the "2010 Form 10-K"). Our financial statements have been prepared in accordance with generally accepted accounting principles ("GAAP") in the United States.

Key References Used in this Quarterly Report

Unless the context requires otherwise, references to "we," "us," "our," "Enterprise" or "Enterprise Products Partners" are intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries. References to "EPO" mean Enterprise Products Operating LLC, which is a wholly owned subsidiary of Enterprise, and its consolidated subsidiaries, through which Enterprise conducts substantially all of its business. Enterprise is managed by its general partner, Enterprise Products Holdings LLC ("Enterprise GP"), which is a wholly owned subsidiary of Dan Duncan LLC, a Delaware limited liability company.

On September 3, 2010, Enterprise GP Holdings L.P. ("Holdings"), Enterprise, Enterprise GP, Enterprise Products GP, LLC ("EPGP," the former general partner of Enterprise) and Enterprise ETE LLC ("Holdings MergerCo," a Delaware limited liability company and a wholly owned subsidiary of Enterprise) entered into a merger agreement (the "Holdings Merger Agreement"). On November 22, 2010, the Holdings Merger Agreement was approved by the unitholders of Holdings and the merger of Holdings with and into Holdings MergerCo and related transactions were completed, with Holdings MergerCo surviving such merger (collectively, we refer to these transactions as the "Holdings Merger"). Enterprise's membership interests in Holdings MergerCo were subsequently contributed to EPO. For additional information regarding the Holdings Merger, see "Basis for Financial Statement Presentation" within this Item 2.

The membership interests of Dan Duncan LLC are owned of record by a voting trust, the current trustees ("DD LLC Trustees") of which are: (i) Randa Duncan Williams, who is also a director of Enterprise GP; (ii) Dr. Ralph S. Cunningham, who is also a director and the Chairman of Enterprise GP and one of three managers of Dan Duncan LLC; and (iii) Richard H. Bachmann, who is also a director of Enterprise GP and one of three managers of Dan Duncan LLC.

References to "EPCO" mean Enterprise Products Company and its privately held affiliates. A majority of the outstanding voting capital stock of EPCO is owned of record by a voting trust, the current trustees ("EPCO Trustees") of which 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 and Chief Executive Officer ("CEO") of EPCO. Ms. Williams, Dr. Cunningham and Mr. Bachmann are also currently directors of EPCO.

References to "Duncan Energy Partners" mean Duncan Energy Partners L.P. (NYSE: DEP), which is a consolidated subsidiary of EPO. References to "DEP GP" mean DEP Holdings, LLC, which is the general partner of Duncan Energy Partners and a wholly owned subsidiary of EPO. See "Significant Recent Developments" included under this Item 2 for information regarding the proposed merger of Duncan Energy Partners with a subsidiary of Enterprise.

References to “TEPPCO” and “TEPPCO GP” mean TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (which is the general partner of TEPPCO), respectively, prior to their

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mergers with our subsidiaries on October 26, 2009. We refer to such related mergers both individually and in the aggregate as the “TEPPCO Merger.”

References to “Energy Transfer Equity” mean the business and operations of Energy Transfer Equity, L.P. (NYSE: ETE) and its consolidated subsidiaries, which include Energy Transfer Partners, L.P. (“ETP”) and Regency Energy Partners LP (“RGNC”). The general partner of Energy Transfer Equity is LE GP, LLC (“LE GP”). We own noncontrolling interests in Energy Transfer Equity, which we account for using the equity method of accounting.

Duncan Energy Partners and Energy Transfer Equity electronically file certain documents with the U.S. Securities and Exchange Commission (“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.

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

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

Cautionary Note Regarding Forward-Looking Statements

This discussion contains various forward-looking statements and information based on our beliefs and those of our general partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as “anticipate,” “project,” “expect,” “plan,” “seek,” “goal,” “estimate,” “forecast,” “intend,” “could,” “believe,” “may,” “potential” and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our general partner believe that the expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any assurances that such expectations will prove to be correct. Forward-looking statements are subject to a variety of

risks, uncertainties and assumptions as described in more detail under Item 1A “Risk Factors” included in our 2010 Form 10-K. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements. The forward-looking statements in this quarterly report speak only as of the date hereof. Except as required by federal and state securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason.

Overview of Business

We are a publicly traded Delaware limited partnership, the common units of which are listed on the NYSE under the ticker symbol “EPD.” We were formed in April 1998 to own and operate certain natural gas liquids (“NGLs”) related businesses of EPCO and are now a leading North American provider of midstream energy services to producers and consumers of natural gas, NGLs, crude oil, refined products and certain petrochemicals. Our midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States, Canada and the Gulf of Mexico with domestic consumers and international markets. Our assets include approximately 50,200 miles of onshore and offshore pipelines; 190 MMBbls of storage capacity for NGLs, refined products and crude oil; and 27 Bcf of natural gas storage capacity.

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Our midstream energy operations include: natural gas gathering, treating, processing, transportation and storage; NGL transportation, fractionation, storage, and import and export terminaling; crude oil and refined products transportation, storage, and terminaling; offshore production platforms; petrochemical transportation and services; and a marine transportation business that operates primarily on the United States inland and Intracoastal Waterway systems and in the Gulf of Mexico. We have 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.

We conduct substantially all of our business through EPO and are owned 100% by our limited partners from an economic perspective. Enterprise GP owns a non-economic general partner interest in us.

Basis of Financial Statement Presentation

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 financial information of businesses that we control (e.g., Duncan Energy Partners). Our general purpose consolidated financial statements present those investments over which we do not have control as unconsolidated affiliates (e.g., our equity method investment in Energy Transfer Equity). Noncontrolling interest reflects third-party and related party ownership of our consolidated subsidiaries.

Prior to the Holdings Merger, Enterprise was a consolidated subsidiary of Holdings, which was Enterprise's parent. Upon completion of the Holdings Merger, Holdings merged with and into a wholly owned subsidiary of Enterprise. The Holdings Merger resulted in Holdings being considered the surviving consolidated entity for accounting purposes, while Enterprise Products Partners L.P. is the surviving consolidated entity for legal and reporting purposes. For accounting purposes, Holdings is deemed the acquirer of the noncontrolling interest in Enterprise that were previously recognized in Holdings' consolidated financial statements (i.e., the acquisition of Enterprise's limited partner interests that were owned by parties other than Holdings).

As a result of the Holdings Merger, Enterprise's consolidated financial and operating results prior to November 22, 2010 have been presented as if Enterprise were Holdings from an accounting perspective (i.e., the financial statements of Holdings became the historical financial statements of Enterprise). While it was a publicly traded partnership, Holdings (NYSE: EPE) electronically filed its annual and quarterly consolidated financial statements with the SEC. You can access this information at www.sec.gov.

The primary differences between Holdings' and Enterprise's consolidated results of operations were (i) general and administrative costs incurred by Holdings and EPGP (our former general partner); (ii) equity in income of Holdings' noncontrolling ownership interests in Energy Transfer Equity; and (iii) interest expense associated with Holdings' debt. In addition, for periods prior to November 22, 2010, the net assets, income, cash distributions and contributions and other amounts attributable to Enterprise's limited partner interests that were owned by third parties and related parties other than Holdings are presented as a component of noncontrolling interest. See Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report for additional information regarding our noncontrolling interest.

Historical limited partner units outstanding and earnings per unit amounts presented in our financial statements have been retroactively presented in connection with the 1.5 to one unit-for-unit exchange that occurred under the Holdings Merger. See Note 13 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report for additional information regarding earnings per unit.

Significant Recent Developments

The following information highlights significant developments since January 1, 2011 through the date of this filing (August 9, 2011), including (i) information relevant to an understanding of our financial

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condition, changes in financial condition or results of operations, and (ii) certain unusual or infrequent events or transactions and known trends or uncertainties that have had or that we reasonably expect may have a material impact on our revenues or income from continuing operations.

Enterprise to Build Sixth NGL Fractionator at Mont Belvieu, Texas Complex

In June 2011, we announced plans to construct a sixth NGL fractionator at our Mont Belvieu, Texas facility that will increase capacity there by 75 MBPD. The new fractionation facility will accommodate continued growth of liquids-rich natural gas production from the prolific Eagle Ford Shale basin in South Texas. All necessary approvals and permits have been obtained and we have started construction of the new facility, which is projected to begin service in late 2012. At that time, we will have the capability to fractionate more than 450 MBPD of NGLs at our Mont Belvieu complex. System-wide our net fractionation capacity will increase to more than 800 MBPD.

Enterprise to Extend Eagle Ford Shale Crude Oil Pipeline System

On May 3, 2011, we announced plans to build an 80-mile extension of our 350 MBPD Eagle Ford Shale crude oil pipeline, which would allow us to serve growing production areas in the southwestern portion of the supply basin. The Phase II project, which is being designed with a capacity of 200 MBPD, would originate in Wilson County, Texas at the terminus of our previously announced 140-mile Phase I segment, and extend to a site near Gardendale, Texas in La Salle County, where a new central delivery point is planned for construction that will feature 500,000 barrels of storage. Phase I is projected to begin service by the second quarter of 2012, with Phase II set to commence operations in the first quarter of 2013. When completed, the approximately 220-mile crude oil pipeline system will provide Eagle Ford Shale producers with access to the Texas Gulf Coast refining complex through our integrated midstream network.

Enterprise and ETP to form pipeline joint venture

On April 26, 2011, we announced an intent to form a 50/50 joint venture with ETP to design and construct a crude oil pipeline from Cushing, Oklahoma to Houston, Texas. The project would allow greater access to the U.S. Gulf Coast-area refining complex and add approximately 500,000 barrels of storage capacity at new facilities to be constructed and owned by the joint venture at our Houston crude oil terminal. The pipeline would provide an outlet for more than 400 MBPD of crude oil supplies which are currently stranded at the Cushing hub and priced at a substantial discount to imported crude oil on the Gulf Coast. The pipeline would also give refiners on the Gulf Coast improved access to growing supplies of domestic crude oil production and an alternative to higher priced crude oil imports, which represent their largest source of supply. Contingent upon receiving satisfactory shipper commitments, the proposed pipeline is projected to begin service in the fourth quarter of 2012. In May 2011, an open commitment period for shippers to contract for available capacity on the proposed pipeline was initiated. The commitment period has been extended to August 12, 2011.

Expansion of Houston Ship Channel Import/Export Terminal

On March 29, 2011, we announced the expansion of our import/export terminal on the Houston Ship Channel. The expansion project is expected to nearly double the fully refrigerated export loading capacity for propane and other NGLs at the facility to more than 10,000 barrels per hour, while enhancing its ability to load multiple vessels simultaneously. We expect to complete the expansion in the second half of 2012.

Agreement and Plan of Merger with Duncan Energy Partners

On April 28, 2011, we entered into an Agreement and Plan of Merger (the “Duncan Merger Agreement”), by and among Enterprise, Enterprise GP, EPD MergerCo LLC (“Duncan MergerCo,” a Delaware limited liability company and a wholly owned subsidiary of Enterprise), Duncan Energy Partners and DEP GP. At the effective time of the merger, Duncan MergerCo will merge with and into Duncan

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Energy Partners, pursuant to the Duncan Merger Agreement, with Duncan Energy Partners surviving the merger as a wholly owned subsidiary of Enterprise (the “Duncan Merger”), and all of the outstanding Duncan Energy Partners common units at the effective time of the merger will be cancelled and converted into the right to receive common units representing limited partner interests in Enterprise based on an exchange rate of 1.01 Enterprise common units for each Duncan Energy Partners common unit.

On September 7, 2011, Duncan Energy Partners will host a special meeting of its unitholders to consider and vote upon approval of the Duncan Merger Agreement and the Duncan Merger. The Duncan Merger Agreement and the Duncan Merger must be approved by the affirmative vote or consent of holders of (i) a majority of the outstanding common units of Duncan Energy Partners and (ii) a majority of the Duncan Energy Partners common units owned by the Duncan Unaffiliated Unitholders (as defined in the Duncan Merger Agreement) that actually vote for or against such approval. In connection with the Duncan Merger Agreement, we, Duncan Energy Partners and Enterprise GTM Holdings L.P., a Delaware limited partnership and a wholly owned subsidiary of Enterprise (“Enterprise GTM”), entered into a Voting Agreement, dated as of April 28, 2011 (the “Voting Agreement”), pursuant to which Enterprise GTM and Enterprise agreed to vote any of the Duncan Energy Partners common units owned by them or their subsidiaries in favor of the adoption of the Duncan Merger Agreement and the Duncan Merger at any meeting of the Duncan Energy Partners unitholders, including the 33,783,587 Duncan Energy Partners common units currently directly owned by Enterprise GTM (representing approximately 58.5% of the outstanding common units of Duncan Energy Partners). The Voting Agreement will terminate upon the termination of the Duncan Merger Agreement.

The Duncan Merger Agreement contains customary representations, warranties and covenants by each of the parties. Completion of the Duncan Merger is conditioned upon, among other things: (i) requisite Duncan Energy Partners unitholder approval of the Duncan Merger Agreement and the Duncan Merger; (ii) applicable regulatory approvals; (iii) the absence of certain legal injunctions or impediments prohibiting the transactions; (iv) the effectiveness of a registration statement on Form S-4 with respect to the issuance by Enterprise of the Enterprise common units in connection with the Duncan Merger (the Form S-4 was declared effective by the SEC on August 1, 2011); (v) the receipt of certain tax opinions; and (vi) approval for the listing of the Enterprise common units issued in connection with the Duncan Merger on the NYSE.

Incident at Mont Belvieu Storage Facility

On February 8, 2011, we experienced an NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility. West Storage consists of ten underground salt dome storage caverns with a storage capacity of approximately 15 MMBbls. Through the reconfiguration of product receipt and delivery capabilities and other measures, we have returned our Mont Belvieu plants and related assets to close to the same capabilities as we had prior to the incident; however, our West Storage location and associated underground storage wells remain partially inoperative at this time. Remaining repairs to this location are underway and are expected to be completed in stages by early 2012. Our insurance deductible for such property damage events was \$5.0 million, which expense was recognized in our earnings for the first quarter of 2011.

Based on current information, we estimate that the total cost related to this incident will approximate \$150 million. We participate as a named insured in EPCO’s insurance program, which provides us with property damage, business interruption and other insurance coverage, the scope and amounts of which we believe are customary and prudent for the nature and extent of our operations. See Note 15 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report for information regarding insurance matters.

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Results of Operations

Selected Price and Volumetric Data

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

	Natural Gas, \$/MMBtu (1)	Ethane, \$/gallon (2)	Propane, \$/gallon (2)	Normal Butane, \$/gallon (2)	Isobutane, \$/gallon (2)	Natural Gasoline, \$/gallon (2)	Polymer Grade Propylene, \$/pound (3)	Refinery Grade Propylene, \$/pound (3)	Crude Oil, \$/barrel (4)
2010									
1st Quarter	\$ 5.30	\$ 0.73	\$ 1.24	\$ 1.52	\$ 1.64	\$ 1.82	\$ 0.63	\$ 0.54	\$ 78.72
2nd Quarter	\$ 4.09	\$ 0.55	\$ 1.08	\$ 1.47	\$ 1.58	\$ 1.81	\$ 0.65	\$ 0.44	\$ 78.03
3rd Quarter	\$ 4.38	\$ 0.48	\$ 1.07	\$ 1.38	\$ 1.43	\$ 1.71	\$ 0.58	\$ 0.44	\$ 76.20
4th Quarter	\$ 3.80	\$ 0.64	\$ 1.26	\$ 1.62	\$ 1.68	\$ 2.00	\$ 0.59	\$ 0.49	\$ 85.17
2010 Averages	\$ 4.39	\$ 0.60	\$ 1.16	\$ 1.50	\$ 1.58	\$ 1.84	\$ 0.61	\$ 0.48	\$ 79.53
2011									
1st Quarter	\$ 4.11	\$ 0.66	\$ 1.37	\$ 1.75	\$ 1.85	\$ 2.27	\$ 0.76	\$ 0.68	\$ 94.10
2nd Quarter	\$ 4.32	\$ 0.78	\$ 1.49	\$ 1.87	\$ 2.02	\$ 2.48	\$ 0.89	\$ 0.79	\$ 102.56
2011 Averages	\$ 4.21	\$ 0.72	\$ 1.43	\$ 1.81	\$ 1.94	\$ 2.38	\$ 0.82	\$ 0.73	\$ 98.33

(1) Natural gas prices are based on Henry-Hub I-FERC commercial index prices.

(2) NGL prices for ethane, propane, normal butane, isobutane and natural gasoline are based on Mont Belvieu Non-TET commercial index prices as reported by Oil Price Information Service.

(3) Polymer-grade propylene prices represent average contract pricing for such product as reported by Chemical Market Associates, Inc. ("CMAI"). Refinery grade propylene prices represent weighted-average spot prices for such product as reported by CMAI.

(4) Crude oil prices are based on commercial index prices for West Texas Intermediate as measured on the New York Mercantile Exchange ("NYMEX").

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
NGL Pipelines & Services, net:				
NGL transportation volumes (MBPD)	2,253	2,194	2,309	2,217
NGL fractionation volumes (MBPD)	545	463	547	468
Equity NGL production (MBPD)	120	125	119	124
Fee-based natural gas processing (MMcf/d)	3,687	2,985	3,692	2,833
Onshore Natural Gas Pipelines & Services, net:				
Natural gas transportation volumes (BBtus/d)	11,891	11,418	11,804	11,300
Onshore Crude Oil Pipelines & Services, net:				
Crude oil transportation volumes (MBPD)	642	678	654	675
Offshore Pipelines & Services, net:				
Natural gas transportation volumes (BBtus/d)	1,039	1,312	1,097	1,359
Crude oil transportation volumes (MBPD)	279	322	289	338
Platform natural gas processing (MMcf/d)	417	568	431	600
Platform crude oil processing (MBPD)	19	17	17	18
Petrochemical & Refined Products Services, net:				
Butane isomerization volumes (MBPD)	103	99	96	86
Propylene fractionation volumes (MBPD)	68	79	71	79
Octane enhancement production volumes (MBPD)	18	13	15	12
Transportation volumes, primarily refined products and petrochemicals (MBPD)	761	857	752	831
Total, net:				
NGL, crude oil, refined products and petrochemical transportation volumes (MBPD)	3,935	4,051	4,004	4,061
Natural gas transportation volumes (BBtus/d)	12,930	12,730	12,901	12,659
Equivalent transportation volumes (MBPD) (1)	7,338	7,401	7,399	7,392

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

Comparison of Results of Operations

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
Revenues	\$11,216.5	\$7,543.4	\$21,400.2	\$16,087.9
Operating costs and expenses	10,533.3	6,974.2	20,070.4	14,946.1
General and administrative costs	50.4	40.5	88.3	80.8

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Equity in income of unconsolidated affiliates	11.1	11.0	27.3	37.6
Operating income	643.9	539.7	1,268.8	1,098.6
Interest expense	188.3	179.2	372.1	337.1
Provision for income taxes	7.4	6.5	14.5	15.2
Net income	448.5	354.4	883.0	746.8
Net income attributable to noncontrolling interest	14.8	300.3	28.6	622.8
Net income attributable to partners	433.7	54.1	854.4	124.0

For information regarding amounts attributable to noncontrolling interest, see Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
NGL Pipelines & Services	\$497.7	\$441.0	\$1,002.1	\$878.3
Onshore Natural Gas Pipelines & Services	161.1	106.9	320.3	237.2
Onshore Crude Oil Pipelines & Services	67.8	25.9	99.6	52.6
Offshore Pipelines & Services	53.4	82.8	114.7	163.9
Petrochemical & Refined Products Services	139.8	158.1	252.2	278.1
Other Investments	2.7	(5.7)	9.0	4.9
Total segment gross operating margin	\$922.5	\$809.0	\$1,797.9	\$1,615.0

For a reconciliation of non-GAAP gross operating margin to GAAP operating income and further to GAAP income before provision for income taxes, see “Other Items – Non-GAAP Reconciliations” included within this Item 2. For additional information regarding our business segments, see Note 11 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
NGL Pipelines & Services:				
Sales of NGLs	\$3,831.5	\$2,804.4	\$7,888.6	\$6,468.5
Sales of other petroleum and related products	0.7	0.7	1.3	1.2
Midstream services	204.7	174.2	403.8	355.9
Total	4,036.9	2,979.3	8,293.7	6,825.6
Onshore Natural Gas Pipelines & Services:				
Sales of natural gas	719.5	655.6	1,432.2	1,630.8
Midstream services	207.8	189.3	411.7	375.6
Total	927.3	844.9	1,843.9	2,006.4
Onshore Crude Oil Pipelines & Services:				
Sales of crude oil	4,257.9	2,603.4	7,606.1	4,970.7
Midstream services	23.7	25.9	46.1	45.2
Total	4,281.6	2,629.3	7,652.2	5,015.9
Offshore Pipelines & Services:				
Sales of natural gas	0.3	0.4	0.6	0.8
Sales of crude oil	2.5	1.9	5.8	4.0
Midstream services	60.9	85.0	121.7	171.1
Total	63.7	87.3	128.1	175.9
Petrochemical & Refined Products Services:				
Sales of petrochemical and refined products	1,718.7	871.7	3,101.5	1,804.3
Midstream services	188.3	130.9	380.8	259.8
Total	1,907.0	1,002.6	3,482.3	2,064.1
Total consolidated revenues	\$11,216.5	\$7,543.4	\$21,400.2	\$16,087.9

Comparison of Three Months Ended June 30, 2011 with Three Months Ended June 30, 2010

Revenues for the second quarter of 2011 were \$11.22 billion compared to \$7.54 billion for the second quarter of 2010, a \$3.67 billion quarter-to-quarter increase. Consolidated revenues from the sale of NGLs, natural gas, crude oil and petrochemicals and refined products increased \$3.59 billion quarter-to-quarter primarily due to higher energy commodity sales prices and crude oil sales volumes. Consolidated revenues from the sale of NGLs and natural gas increased \$1.03 billion and \$63.8 million quarter-to

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quarter, respectively, due to higher sales prices during the second quarter of 2011 compared to the second quarter of 2010. Crude oil sales revenues increased \$1.66 billion quarter-to-quarter attributable to both higher crude oil sales prices and volumes. Consolidated revenues from the sale of petrochemicals and refined products increased \$847.0 million quarter-to-quarter primarily due to higher propylene and refined products sales prices during the second quarter of 2011 compared to the second quarter of 2010. Consolidated revenues also increased \$75.0 million quarter-to-quarter due to (i) the addition of revenues from businesses we acquired or assets we constructed and placed into service since the second quarter of 2010 (e.g., the trucking business we acquired from EPCO in September 2010, the start-up of our fourth NGL fractionator in Mont Belvieu in November 2010, and the start-up of newly constructed natural gas gathering systems in the Haynesville Shale supply basin) and (ii) the timing of the State Line and Fairplay acquisitions in May 2010 (i.e., the second quarter of 2010 includes only a partial quarter of revenues from these acquired gathering systems).

Operating costs and expenses were \$10.53 billion for the second quarter of 2011 compared to \$6.97 billion for the second quarter of 2010, a \$3.56 billion quarter-to-quarter increase. The cost of sales of our marketing activities increased \$3.03 billion quarter-to-quarter primarily due to higher energy commodity prices and crude oil sales volumes. The operating costs and expenses of our natural gas processing plants increased \$367.5 million quarter-to-quarter primarily due to higher natural gas processing volumes and energy commodity prices in the second quarter of 2011 relative to the second quarter of 2010. In general, higher natural gas prices result in increased plant thermal reduction costs at our natural gas processing plants; likewise, higher NGL prices result in increased operating costs associated with percent-of-proceeds and margin-band types of natural gas processing contracts. Consolidated operating costs and expenses also increased \$66.2 million quarter-to-quarter due to (i) the addition of operating costs from businesses we acquired or assets we constructed and placed into service since the second quarter of 2010 and (ii) the timing of the State Line and Fairplay acquisitions in May 2010 (i.e., the second quarter of 2010 includes only a partial quarter of operating costs from these acquired gathering systems).

Changes in our revenues and operating costs and expenses quarter-to-quarter are explained in part by changes in energy commodity prices. For example, higher energy commodity prices result in an increase in revenues attributable to the sale of NGLs, natural gas, crude oil and petrochemicals and refined products; however, these same higher energy commodity prices also increase the associated cost of sales as purchase prices rise. The weighted-average indicative market price for NGLs was \$1.50 per gallon during the second quarter of 2011 versus \$1.11 per gallon during the second quarter of 2010 – a 35% quarter-to-quarter increase. Our determination of the weighted-average indicative market price for NGLs is based on U.S. Gulf Coast prices for such products at Mont Belvieu, Texas, which is the primary industry hub for domestic NGL production. The market price of natural gas (as measured at Henry Hub in Louisiana) averaged \$4.32 per MMBtu during the second quarter of 2011 versus \$4.09 per MMBtu during the second quarter of 2010 – a 6% quarter-to-quarter increase. Also, the market price of crude oil (as measured on the NYMEX) averaged \$102.56 per barrel during the second quarter of 2011 compared to \$78.03 per barrel during the second quarter of 2010 – a 31% quarter-to-quarter increase. See “Selected Price and Volumetric Data” included within this Item 2 for historical energy commodity pricing information relevant to our business.

General and administrative costs were \$50.4 million for the second quarter of 2011 compared to \$40.5 million for the second quarter of 2010. The \$9.9 million quarter-to-quarter increase in general and administrative costs is primarily due to costs associated with the proposed Duncan Merger and higher employee compensation expenses.

Equity earnings from unconsolidated affiliates were \$11.1 million for the second quarter of 2011 compared to \$11.0 million for the second quarter of 2010. A quarter-to-quarter increase in equity earnings of \$8.4 million from Energy Transfer Equity was offset by the effects of lower throughput volumes during the second quarter of 2011 on pipeline assets owned by Seaway Crude Pipeline Company (“Seaway”), Centennial Pipeline LLC (“Centennial”) and our investees operating in the Gulf of Mexico.

Operating income for the second quarter of 2011 was \$643.9 million compared to \$539.7 million for the second quarter of 2010. Collectively, the aforementioned changes in consolidated revenues, costs

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and expenses and equity earnings resulted in a \$104.2 million quarter-to-quarter increase in operating income.

Interest expense increased to \$188.3 million for the second quarter of 2011 from \$179.2 million for the second quarter of 2010. The \$9.1 million quarter-to-quarter increase in interest expense is primarily due to a higher average outstanding debt principal balance during the second quarter of 2011 compared to the second quarter of 2010. Average debt principal outstanding increased to \$14.23 billion during the second quarter of 2011 from \$13.05 billion during the second quarter of 2010.

Consolidated net income increased \$94.1 million quarter-to-quarter to \$448.5 million for the second quarter of 2011 from \$354.4 million for the second quarter of 2010. Net income attributable to noncontrolling interests was \$14.8 million for the second quarter of 2011 compared to \$300.3 million for the second quarter of 2010, which included \$284.2 million attributable to the limited partners of Enterprise other than Holdings. For periods prior to the Holdings Merger (e.g., the second quarter of 2010), that portion of Enterprise's net income attributable to its limited partner interests owned by third parties and related parties other than Holdings is presented as a component of net income attributable to noncontrolling interests. See Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report for information regarding noncontrolling interests. Net income attributable to partners increased \$379.6 million quarter-to-quarter to \$433.7 million for the second quarter of 2011 compared to \$54.1 million for the second quarter of 2010.

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

NGL Pipelines & Services. Gross operating margin from this business segment was \$497.7 million for the second quarter of 2011 compared to \$441.0 million for the second quarter of 2010, a \$56.7 million quarter-to-quarter increase.

Gross operating margin from our natural gas processing and related NGL marketing business was \$303.2 million for the second quarter of 2011 compared to \$267.9 million for the second quarter of 2010, a \$35.3 million quarter-to-quarter increase. Gross operating margin from our NGL marketing activities increased \$32.2 million quarter-to-quarter due to higher sales margins. Gross operating margin from our Louisiana natural gas processing plants increased \$8.9 million quarter-to-quarter primarily due to higher equity NGL production volumes and processing margins during the second quarter of 2011 compared to the second quarter of 2010. Natural gas processing activities on the Fairplay gathering system, which we acquired in May 2010, contributed \$3.2 million of the quarter-to-quarter increase in gross operating margin. Collectively, gross operating margin from the remainder of our natural gas processing activities decreased \$9.0 million quarter-to-quarter primarily due to lower equity NGL production and processing margins at our natural gas processing plants located in the Rocky Mountains during the second quarter of 2011 compared to the second quarter of 2010.

Gross operating margin from our NGL pipelines and related storage business was \$142.6 million for the second quarter of 2011 compared to \$138.9 million for the second quarter of 2010, a \$3.7 million quarter-to-quarter increase. Total NGL transportation volumes increased to 2,253 MBPD during the second quarter of 2011 from 2,194 MBPD during the second quarter of 2010. Gross operating margin from our Mid-America Pipeline System, Seminole Pipeline and related terminals increased \$10.4 million quarter-to-quarter primarily due to higher transportation revenues attributable to an increase in volumes delivered under higher tariffs during the second quarter of 2011 compared to the second quarter of 2010. Gross operating margin from our Dixie Pipeline decreased \$7.0 million quarter-to-quarter primarily due lower throughput volumes and costs attributable to pipeline integrity testing.

Gross operating margin from our NGL fractionation business was \$51.9 million for the second quarter of 2011 compared to \$34.2 million for the second quarter of 2010, a \$17.7 million quarter-to-quarter increase. Our NGL fractionation volumes were 545 MBPD during the second quarter of 2011 compared to 463 MBPD during the second quarter of 2010. Gross operating margin from our Mont Belvieu NGL fractionators increased \$11.3 million quarter-to-quarter primarily due to higher NGL

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fractionation volumes and fees. During the fourth quarter of 2010, we placed into service a fourth NGL fractionator at our Mont Belvieu complex, which added 75 MBPD of NGL fractionation capacity at this key industry hub. Gross operating margin from our Norco NGL fractionation facility increased \$4.3 million quarter-to-quarter primarily due to higher NGL prices, which resulted in higher revenues associated with percent-of-liquids contracts and product blending activities. Gross operating margin from our Hobbs NGL fractionation facility increased \$3.8 million quarter-to-quarter due to higher fractionation volumes and fees. Results for the second quarter of 2011 do not include any contributions from our former Colorado NGL fractionators, which we sold during March 2011. These fractionation facilities contributed \$1.6 million of gross operating margin for the second quarter of 2010.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was \$161.1 million for the second quarter of 2011 compared to \$106.9 million for the second quarter of 2010, a \$54.2 million quarter-to-quarter increase. Onshore natural gas transportation volumes were 11.89 TBtus/d during the second quarter of 2011 compared to 11.42 TBtus/d during the second quarter of 2010.

Gross operating margin from our onshore natural gas pipelines and related marketing business was \$150.6 million for the second quarter of 2011 compared to \$95.4 million for the second quarter of 2010, a \$55.2 million quarter-to-quarter increase. Gross operating margin from our natural gas marketing activities increased \$27.2 million quarter-to-quarter due to higher sales margins and improved mark-to-market results related to certain derivative contracts. Gross operating margin from our Texas Intrastate System increased \$14.6 million quarter-to-quarter primarily due to higher firm capacity reservation revenues and natural gas throughput volumes. Increased natural gas production volumes from the Eagle Ford Shale supply basin resulted in stronger demand for our natural gas transportation services during the second quarter of 2011 compared to the same period last year. Gross operating margin from our San Juan Gathering System increased \$9.3 million quarter-to-quarter largely due to increased volumes and higher fee-based revenues. Our State Line and Fairplay natural gas gathering systems, which we acquired in May 2010, contributed \$8.1 million of the quarter-to-quarter increase in gross operating margin. Gross operating margin from the remainder of our onshore natural gas pipelines and related marketing business decreased \$4.0 million quarter-to-quarter primarily due to lower gathering volumes on our Jonah and Carlsbad Gathering Systems.

Gross operating margin from our natural gas storage business was \$10.5 million for the second quarter of 2011 compared to \$11.5 million for the second quarter of 2010. The \$1.0 million quarter-to-quarter decrease in gross operating margin is primarily due to higher operating expenses associated with underground storage cavern leaching activities at our Petal natural gas storage facility during the second quarter of 2011.

Onshore Crude Oil Pipelines & Services. Gross operating margin from this business segment was \$67.8 million for the second quarter of 2011 compared to \$25.9 million for the second quarter of 2010, a \$41.9 million quarter-to-quarter increase. Total onshore crude oil transportation volumes were 642 MBPD during the second quarter of 2011 compared to 678 MBPD during the second quarter of 2010. Gross operating margin from our crude oil marketing and related activities increased \$35.2 million quarter-to-quarter primarily due to higher sales volumes and margins. Our crude oil marketing activities benefited from increased crude oil production volumes from the Eagle Ford Shale, Barnett Shale and West Texas supply basins. Collectively, gross operating margin from our South Texas System, West Texas System, Red River Pipeline and Basin Pipeline increased \$9.6 million quarter-to-quarter primarily due to a 61 MBPD increase in throughput volumes. Equity earnings from our investment in Seaway decreased \$5.2 million quarter-to-quarter primarily due to lower volumes delivered to Cushing, Oklahoma from the Texas Gulf Coast during the second quarter of 2011 compared to the second quarter of 2010. Net to our interest, throughput volumes on the Seaway pipeline system decreased 97 MBPD quarter-to-quarter. Collectively, gross operating margin from the remainder of our onshore crude oil businesses increased \$2.3 million quarter-to-quarter primarily due to improved operating results from our terminal operations in Midland, Texas and Cushing, Oklahoma.

Offshore Pipelines & Services. Gross operating margin from this business segment was \$53.4 million for the second quarter of 2011 compared to \$82.8 million for the second quarter of 2010, a \$29.4 million quarter-to-quarter decrease. Results for the second quarter of 2010 benefited from \$10.3 million of

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gains related to insurance proceeds. Excluding the effects of insurance proceeds, gross operating margin from this business segment decreased \$19.1 million quarter-to-quarter primarily due to the effects of last year's federal offshore drilling moratorium, which was in effect from May 2010 to October 2010, and the ongoing deliberations of federal authorities to approve drilling and well workover permits. Although crude oil and natural gas drilling activity has resumed on a limited basis, certain of our offshore pipeline and platform assets continue to experience reduced throughput volumes, as existing wells experience natural production declines. We expect that drilling activity in the Gulf of Mexico will increase in the future as federal agencies allow exploration and production companies to proceed with the drilling of new wells.

Gross operating margin from our offshore crude oil pipeline business was \$18.6 million for the second quarter of 2011 compared to \$25.9 million for the second quarter of 2010, a \$7.3 million quarter-to-quarter decrease. Total offshore crude oil transportation volumes averaged 279 MBPD during the second quarter of 2011 compared to 322 MBPD during the second quarter of 2010. Collectively, equity earnings from our investments in Poseidon Oil Pipeline Company, L.L.C. ("Poseidon") and Cameron Highway Oil Pipeline Company ("Cameron Highway") decreased \$4.3 million quarter-to-quarter primarily due to lower throughput volumes. Net to our interest, crude oil throughput volumes on the Poseidon and Cameron Highway pipelines decreased 43 MBPD quarter-to-quarter. In addition, gross operating margin from our Shenzi Oil Pipeline decreased \$2.3 million quarter-to-quarter primarily due to an 18 MBPD decrease in throughput volumes. Collectively, gross operating margin from the remainder of our offshore crude oil pipeline business decreased \$0.7 million quarter-to-quarter primarily due to higher operating costs and expenses on our Constitution Oil Pipeline during the second quarter of 2011 compared to the second quarter of 2010.

Gross operating margin from our offshore natural gas pipeline business was \$7.0 million for the second quarter of 2011 compared to \$14.4 million for the second quarter of 2010, a \$7.4 million quarter-to-quarter decrease. Total offshore natural gas transportation volumes were 1,039 BBtus/d during the second quarter of 2011 versus 1,312 BBtus/d during the second quarter of 2010. Gross operating margin from our Independence Trail pipeline decreased \$4.0 million quarter-to-quarter primarily due to lower transportation volumes. Natural gas transportation volumes on our Independence Trail pipeline decreased to 477 BBtus/d during the second quarter of 2011 from 635 BBtus/d during the second quarter of 2010 as a result of lower volumes from the Independence Hub platform (see below). Gross operating margin from our High Island Offshore System decreased \$5.0 million quarter-to-quarter primarily due to the second quarter of 2010 including \$4.2 million of revenues attributable to a rate case settlement. Collectively, gross operating margin from the remainder of our offshore natural gas pipeline business increased \$1.6 million quarter-to-quarter primarily due to lower operating expenses on our Viosca Knoll Gathering System during the second quarter of 2011 compared to the second quarter of 2010.

Gross operating margin from our offshore platform services business was \$27.8 million for the second quarter of 2011 compared to \$32.2 million for the second quarter of 2010, a \$4.4 million quarter-to-quarter decrease. On a net basis to our interest, platform natural gas processing volumes were 417 MMcf/d during the second quarter of 2011 compared to 568 MMcf/d during the second quarter of 2010. The quarter-to-quarter decrease in gross operating margin is primarily due to lower natural gas processing volumes from production fields served by our Independence Hub platform as a result of depletion at existing wells, the watering-out of certain wells, and the impact of the federal offshore drilling moratorium which has slowed the drilling of new wells.

Petrochemical & Refined Products Services. Gross operating margin from this business segment was \$139.8 million for the second quarter of 2011 compared to \$158.1 million for the second quarter of 2010, an \$18.3 million quarter-to-quarter decrease.

Gross operating margin from propylene fractionation and related activities was \$31.2 million for the second quarter of 2011 compared to \$67.6 million for the second quarter of 2010, a \$36.4 million quarter-to-quarter decrease. Propylene fractionation volumes were 68 MBPD during the second quarter of 2011 compared to 79 MBPD

during the second quarter of 2010. The quarter-to-quarter decrease in gross operating margin is primarily due to lower propylene fractionation volumes and sales margins during the second quarter of 2011 compared to the second quarter of 2010. Results for the second quarter of 2010

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benefited from the combined effects of high demand for propylene and lower propylene production from third-party petrochemical facilities, while second quarter 2011 volumes were lower due to refinery turnarounds.

Gross operating margin from butane isomerization was \$34.7 million for the second quarter of 2011 compared to \$26.2 million for the second quarter of 2010, an \$8.5 million quarter-to-quarter increase. Butane isomerization volumes increased to 103 MBPD during the second quarter of 2011 from 99 MBPD during the second quarter of 2010. The quarter-to-quarter increase in gross operating margin is primarily due to higher isomerization volumes and commodity prices, which resulted in increased by-product production and associated sales margins.

Gross operating margin from octane enhancement was \$37.2 million for the second quarter of 2011 compared to \$10.9 million for the second quarter of 2010. The \$26.3 million quarter-to-quarter increase in gross operating margin is primarily due to higher sales volumes and margins during the second quarter of 2011 compared to the second quarter of 2010. Production volumes from our Mont Belvieu octane enhancement facility were 18 MBPD during the second quarter of 2011 compared to 13 MBPD during the second quarter of 2010.

Gross operating margin from our refined products pipelines and related activities was \$22.2 million for the second quarter of 2011 compared to \$30.9 million for the second quarter of 2010, an \$8.7 million quarter-to-quarter decrease. Pipeline transportation volumes for the refined products business decreased to 635 MBPD during the second quarter of 2011 from 713 MBPD during the second quarter of 2010. Gross operating margin from our Products Pipeline System decreased \$6.3 million quarter-to-quarter primarily due to higher operating expenses for maintenance and pipeline integrity projects during the second quarter of 2011 compared to the second quarter of 2010. Equity earnings from our investment in Centennial decreased \$1.4 million quarter-to-quarter primarily due to lower transportation volumes. Net to our interest, transportation volumes on the Centennial pipeline decreased 17 MBPD quarter-to-quarter. Gross operating margin from the marketing of refined products decreased \$1.0 million quarter-to-quarter.

Gross operating margin from marine transportation and other services was \$14.5 million for the second quarter of 2011 compared to \$22.5 million for the second quarter of 2010. The \$8.0 million quarter-to-quarter decrease in gross operating margin is primarily due to the second quarter of 2010 including a one-time \$6.2 million benefit recorded in operating expenses for the marine transportation business.

Other Investments. Our equity earnings from Energy Transfer Equity were \$2.7 million for the second quarter of 2011 compared to a loss of \$5.7 million for the second quarter of 2010, an \$8.4 million quarter-to-quarter increase. According to financial statements filed with the SEC, Energy Transfer Equity reported operating income of \$260.6 million for the second quarter of 2011 compared to \$179.3 million for the second quarter of 2010. The \$81.3 million quarter-to-quarter increase in Energy Transfer Equity's operating income is primarily due to earnings generated from recently acquired businesses and newly constructed assets, principally a NGL storage, fractionation and transportation business acquired in May 2011 and ETP's Tiger pipeline that was placed into service in December 2010. Collectively, other income and expense items for Energy Transfer Equity added a net \$47.1 million of earnings quarter-to-quarter primarily due to improved earnings from non-hedged interest rate derivatives of \$24.4 million, higher equity earnings from unconsolidated affiliates of \$16.6 million due to acquisitions and the second quarter of 2010 results including an impairment charge of \$52.6 million related to an unconsolidated affiliate, all of which were partially offset by a \$52.5 million increase in interest expense. Our equity income from this investment was reduced by \$8.4 million and \$9.1 million of excess cost amortization for the second quarters of 2011 and 2010, respectively.

Comparison of Six Months Ended June 30, 2011 with Six Months Ended June 30, 2010

Revenues for the first six months of 2011 were \$21.40 billion compared to \$16.09 billion for the first six months of 2010, a \$5.31 billion period-to-period increase. Consolidated revenues from the sale of NGLs increased \$1.42 billion period-to-period primarily due to higher sales prices during the first six

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months of 2011 compared to the first six months of 2010. Revenues from the sale of natural gas decreased \$198.8 million period-to-period due to lower sales prices and volumes. Crude oil sales revenues increased \$2.64 billion period-to-period attributable to both higher sales prices and volumes. Consolidated revenues from the sale of petrochemicals and refined products increased \$1.30 billion period-to-period primarily due to higher propylene and refined products sales prices during the first six months of 2011 compared to the first six months of 2010. Consolidated revenues also increased \$156.3 million period-to-period due to (i) the addition of revenues from businesses we acquired or assets we constructed and placed into service since the second quarter of 2010 and (ii) the timing of the State Line and Fairplay acquisitions in May 2010 (i.e., 2010 includes only a partial period of revenues from these acquired gathering systems).

Operating costs and expenses were \$20.07 billion for the first six months of 2011 compared to \$14.95 billion for the first six months of 2010, a \$5.12 billion period-to-period increase. The cost of sales of our marketing activities increased \$4.31 billion period-to-period primarily due to higher crude oil sales volumes and, with the exception of natural gas, higher energy commodity prices. The operating costs and expenses of our natural gas processing plants increased \$526.7 million period-to-period primarily due to higher natural gas processing volumes and NGL prices in the first six months of 2011 relative to the first six months of 2010. In general, higher NGL prices result in increased operating costs associated with percent-of-proceeds and margin-band types of natural gas processing contracts. Consolidated operating costs and expenses also increased \$134.6 million period-to-period due to (i) the addition of operating costs from businesses we acquired or assets we constructed and placed into service since the second quarter of 2010 and (ii) the timing of the State Line and Fairplay acquisitions in May 2010 (i.e., 2010 includes only a partial period of operating costs from these acquired gathering systems).

Changes in our revenues and operating costs and expenses period-to-period are explained in part by changes in energy commodity prices. The weighted-average indicative market price for NGLs was \$1.43 per gallon during the first six months of 2011 versus \$1.17 per gallon during the first six months of 2010 – a 22% period-to-period increase. The Henry Hub market price of natural gas averaged \$4.21 per MMBtu during the first six months of 2011 versus \$4.70 per MMBtu during the first six months of 2010 – a 10% period-to-period decrease. The NYMEX crude oil market price averaged \$98.33 per barrel during the first six months of 2011 compared to \$78.37 per barrel during the first six months of 2010 – a 25% period-to-period increase.

General and administrative costs were \$88.3 million for the first six months of 2011 compared to \$80.8 million for the first six months of 2010. The \$7.5 million period-to-period increase in general and administrative costs is primarily due to costs associated with the proposed Duncan Merger and higher employee compensation expenses.

Equity earnings from our unconsolidated affiliates were \$27.3 million for the first six months of 2011 compared to \$37.6 million for the first six months of 2010, a \$10.3 million period-to-period decrease. Collectively, equity earnings from pipeline assets owned by Seaway, Centennial and our investees operating in the Gulf of Mexico decreased \$19.7 million period-to-period primarily due to lower throughput volumes during the first six months of 2011 compared to the first six months of 2010. Equity earnings from Energy Transfer Equity increased \$4.1 million period-to-period as discussed below. Collectively, equity earnings from our other investments increased \$5.3 million period-to-period primarily due to improved results from our investments in midstream energy companies operating in southern Louisiana.

Operating income for the first six months of 2011 was \$1.27 billion compared to \$1.10 billion for the first six months of 2010. Collectively, the aforementioned changes in consolidated revenues, costs and expenses and equity earnings resulted in a \$170.2 million period-to-period increase in operating income.

Interest expense increased to \$372.1 million for the first six months of 2011 from \$337.1 million for the first six months of 2010. The \$35.0 million period-to-period increase in interest expense is primarily due to a higher average

outstanding debt principal balance during the first six months of 2011 compared to the first six months of 2010. Average debt principal outstanding increased to \$14.18 billion during the first six months of 2011 from \$12.72 billion during the first six months of 2010.

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Consolidated net income increased \$136.2 million period-to-period to \$883.0 million for the first six months of 2011 from \$746.8 million for the first six months of 2010. Net income attributable to noncontrolling interests was \$28.6 million for the first six months of 2011 compared to \$622.8 million for the first six months of 2010, which included \$590.7 million attributable to the limited partners of Enterprise other than Holdings. For periods prior to the Holdings Merger (e.g., the first six months of 2010), that portion of Enterprise's net income attributable to its limited partner interests owned by third parties and related parties other than Holdings is presented as a component of net income attributable to noncontrolling interests. Net income attributable to partners increased \$730.4 million period-to-period to \$854.4 million for the first six months of 2011 from \$124.0 million for the first six months of 2010.

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

NGL Pipelines & Services. Gross operating margin from this business segment was \$1.00 billion for the first six months of 2011 compared to \$878.3 million for the first six months of 2010, a \$123.8 million period-to-period increase.

Gross operating margin from our natural gas processing and related NGL marketing business was \$580.9 million for the first six months of 2011 compared to \$527.6 million for the first six months of 2010, a \$53.3 million period-to-period increase. Gross operating margin from our NGL marketing activities increased \$49.4 million period-to-period primarily due to higher sales margins. Gross operating margin from our Louisiana natural gas processing plants increased \$10.5 million period-to-period primarily due to higher equity NGL production volumes and processing margins during the first six months of 2011 compared to the first six months of 2010. Natural gas processing activities on the Fairplay gathering system, which we acquired in May 2010, contributed \$7.1 million of the period-to-period increase in gross operating margin. Gross operating margin from our natural gas processing plants located in the Rocky Mountains decreased \$7.6 million period-to-period primarily due to lower equity NGL production volumes at our Pioneer natural gas processing facility, which experienced scheduled downtime for maintenance activities in June 2011. Collectively, gross operating margin from the remainder of our natural gas processing activities decreased \$6.1 million period-to-period primarily due to lower equity NGL production volumes in Texas and higher maintenance expenses at our Chaco natural gas processing facility during the first six months of 2011 compared to the first six months of 2010.

Gross operating margin from our NGL pipelines and related storage business was \$322.5 million for the first six months of 2011 compared to \$289.0 million for the first six months of 2010, a \$33.5 million period-to-period increase. Total NGL transportation volumes increased to 2,309 MBPD during the first six months of 2011 from 2,217 MBPD during the first six months of 2010. Gross operating margin from our Mid-America Pipeline System, Seminole Pipeline and related NGL terminals increased \$22.0 million period-to-period primarily due to higher transportation revenues attributable to an increase in volumes delivered under higher tariffs during the first six months of 2011 compared to the first six months of 2010. Gross operating margin from our NGL storage activities increased \$8.4 million period-to-period primarily due to an increase in storage and terminalling fees, which was partially offset by the \$5.0 million property damage deductible we expensed in February 2011 related to the West Storage incident at our Mont Belvieu complex. See "Significant Recent Developments" within this Item 2 for information regarding a February 2011 NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility. Collectively, gross operating margin from our Louisiana NGL Pipeline System and Lou-Tex NGL Pipeline increased \$6.3 million period-to-period primarily due to a 41 MBPD increase in throughput volumes. Gross operating margin from the Dixie Pipeline decreased \$8.4 million period-to-period primarily due to a 16 MBPD decrease in transportation volumes and higher pipeline integrity expenses during the first six months of 2011. Gross operating margin from the remainder of our NGL pipelines and related storage business increased \$5.2 million period-to-period primarily due to increased net operational measurement and well gains during the first six months of 2011 when compared to the first six months of 2010.

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Gross operating margin from our NGL fractionation business was \$98.7 million for the first six months of 2011 compared to \$61.7 million for the first six months of 2010, a \$37.0 million period-to-period increase. Our NGL fractionation volumes were 547 MBPD during the first six months of 2011 compared to 468 MBPD during the first six months of 2010. Gross operating margin from our Mont Belvieu NGL fractionators increased \$29.9 million period-to-period primarily due to higher NGL fractionation volumes and fees. During the fourth quarter of 2010, we placed into service a fourth NGL fractionator at our Mont Belvieu complex, which added 75 MBPD of NGL fractionation capacity at this key industry hub. Gross operating margin from our Norco NGL fractionation facility increased \$5.0 million period-to-period primarily due to higher NGL prices, which resulted in higher revenues associated with percent-of-liquids contracts and product blending activities. Collectively, gross operating margin from the remainder of our NGL fractionation business increased \$2.1 million period-to-period primarily due to higher NGL fractionation volumes in South Texas and higher fees at our Hobbs NGL fractionation facility.

Onshore Natural Gas Pipelines & Services. Gross operating margin from this business segment was \$320.3 million for the first six months of 2011 compared to \$237.2 million for the first six months of 2010, an \$83.1 million period-to-period increase. Onshore natural gas transportation volumes were 11.80 TBtus/d during the first six months of 2011 compared to 11.30 TBtus/d during the first six months of 2010.

Gross operating margin from our onshore natural gas pipelines and related marketing business was \$296.6 million for the first six months of 2011 compared to \$211.4 million for the first six months of 2010, an \$85.2 million period-to-period increase. Gross operating margin from our natural gas marketing activities increased \$33.0 million period-to-period primarily due to higher sales margins. Our State Line and Fairplay natural gas gathering systems, which we acquired in May 2010, contributed \$22.9 million of the period-to-period increase in gross operating margin. Gross operating margin from our Texas Intrastate System increased \$24.0 million period-to-period primarily due to higher firm capacity reservation revenues and increased natural gas throughput volumes produced from the Eagle Ford Shale supply basin. Gross operating margin from our San Juan Gathering System increased \$10.1 million period-to-period primarily due to increased volumes and higher fee-based revenues. Gross operating margin from the remainder of our onshore natural gas pipelines and related marketing business decreased \$4.8 million period-to-period primarily due to lower gathering volumes on our Jonah Gathering System.

Gross operating margin from our natural gas storage business was \$23.7 million for the first six months of 2011 compared to \$25.8 million for the first six months of 2010. The \$2.1 million period-to-period decrease in gross operating margin is primarily due to lower demand for interruptible natural gas storage services and higher operating expenses at our Mississippi facilities during the first six months of 2011.

Onshore Crude Oil Pipelines & Services. Gross operating margin from this business segment was \$99.6 million for the first six months of 2011 compared to \$52.6 million for the first six months of 2010, a \$47.0 million period-to-period increase. Total onshore crude oil transportation volumes were 654 MBPD during the first six months of 2011 compared to 675 MBPD during the first six months of 2010. Gross operating margin from our crude oil marketing and related activities increased \$40.8 million period-to-period primarily due to higher sales volumes and margins. Our crude oil marketing activities benefited from increased crude oil production volumes from the Eagle Ford Shale, Barnett Shale and West Texas supply basins. Collectively, gross operating margin from our South Texas System, West Texas System, Red River Pipeline and Basin Pipeline increased \$12.4 million period-to-period primarily due to a 51 MBPD increase in throughput volumes. Equity earnings from our investment in Seaway decreased \$8.0 million period-to-period primarily due to lower volumes delivered to Cushing, Oklahoma from the Texas Gulf Coast during the first six months of 2011 compared to the first six months of 2010. Net to our interest, throughput volumes on the Seaway pipeline system decreased 73 MBPD period-to-period. Collectively, gross operating margin from the remainder of our onshore crude oil businesses increased \$1.8 million period-to-period primarily due to improved operating results from our terminal operations in Midland, Texas and Cushing, Oklahoma.

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Offshore Pipelines & Services. Gross operating margin from this business segment was \$114.7 million for the first six months of 2011 compared to \$163.9 million for the first six months of 2010, a \$49.2 million period-to-period decrease. Results for the first six months of 2010 include \$19.3 million of gains related to insurance proceeds. Excluding the effects of insurance proceeds, gross operating margin from this business segment decreased \$29.9 million period-to-period primarily due to the effects of last year's federal offshore drilling moratorium and the ongoing deliberations of federal authorities to approve drilling and well workover permits.

Gross operating margin from our offshore crude oil pipeline business was \$39.1 million for the first six months of 2011 compared to \$51.2 million for the first six months of 2010, a \$12.1 million period-to-period decrease. Total offshore crude oil transportation volumes averaged 289 MBPD during the first six months of 2011 compared to 338 MBPD during the first six months of 2010. Collectively, equity earnings from our investments in Poseidon and Cameron Highway decreased \$7.3 million period-to-period primarily due to lower throughput volumes. Net to our interest, crude oil throughput volumes on the Poseidon and Cameron Highway pipelines decreased 40 MBPD period-to-period. Collectively, gross operating margin from the remainder of our offshore crude oil pipeline business decreased \$4.8 million period-to-period primarily due to a 26 MBPD decrease in throughput volumes on our Shenzhi and Constitution Oil Pipelines.

Gross operating margin from our offshore natural gas pipeline business was \$17.7 million for the first six months of 2011 compared to \$26.3 million for the first six months of 2010, an \$8.6 million period-to-period decrease. Total offshore natural gas transportation volumes were 1,097 BBtus/d during the first six months of 2011 versus 1,359 BBtus/d during the first six months of 2010. Gross operating margin from our Independence Trail pipeline decreased \$9.2 million period-to-period primarily due to lower transportation volumes. Natural gas transportation volumes on our Independence Trail pipeline decreased to 494 BBtus/d during the first six months of 2011 from 676 BBtus/d during the first six months of 2010 as a result of lower volumes from the Independence Hub platform (see below). Gross operating margin from our High Island Offshore System decreased \$3.6 million period-to-period primarily due to the first six months of 2010 including \$4.2 million of revenues attributable to a rate case settlement. Collectively, gross operating margin from the remainder of our offshore natural gas pipeline business increased \$4.2 million period-to-period primarily due to lower operating expenses on our Viosca Knoll Gathering System during the first six months of 2011 compared to the first six months of 2010.

Gross operating margin from our offshore platform services business was \$57.9 million for the first six months of 2011 compared to \$67.1 million for the first six months of 2010, a \$9.2 million period-to-period decrease. On a net basis to our interest, platform natural gas processing volumes were 431 MMcf/d during the first six months of 2011 compared to 600 MMcf/d during the first six months of 2010. The period-to-period decrease in gross operating margin is primarily due to lower natural gas processing volumes from production fields served by our Independence Hub platform as a result of depletion at existing wells, the watering-out of certain wells, and the impact of the federal offshore drilling moratorium which has slowed the drilling of new wells.

Petrochemical & Refined Products Services. Gross operating margin from this business segment was \$252.2 million for the first six months of 2011 compared to \$278.1 million for the first six months of 2010, a \$25.9 million period-to-period decrease.

Gross operating margin from propylene fractionation and related activities was \$80.0 million for the first six months of 2011 compared to \$110.7 million for the first six months of 2010, a \$30.7 million period-to-period decrease. Propylene fractionation volumes were 71 MBPD during the first six months of 2011 compared to 79 MBPD during the first six months of 2010. The period-to-period decrease in gross operating margin is primarily due to lower propylene fractionation volumes and sales margins during the first six months of 2011 compared to the first six months of 2010. Results for the first six months of 2010 benefited from the combined effects of high demand for propylene and lower propylene production from third-party petrochemical facilities.

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Gross operating margin from butane isomerization was \$60.4 million for the first six months of 2011 compared to \$41.0 million for the first six months of 2010, a \$19.4 million period-to-period increase. Butane isomerization volumes increased to 96 MBPD during the first six months of 2011 from 86 MBPD during the first six months of 2010. The period-to-period increase in gross operating margin is primarily due to higher isomerization volumes and commodity prices, which resulted in increased by-product production and associated sales margins.

Gross operating margin from octane enhancement was \$43.3 million for the first six months of 2011 compared to \$15.0 million for the first six months of 2010. The \$28.3 million period-to-period increase in gross operating margin is primarily due to higher sales volumes and margins and lower maintenance expenses during the first six months of 2011 compared to the first six months of 2010. Production volumes from our Mont Belvieu octane enhancement facility were 15 MBPD during the first six months of 2011 compared to 12 MBPD during the first six months of 2010.

Gross operating margin from our refined products pipelines and related activities was \$40.5 million for the first six months of 2011 compared to \$79.8 million for the first six months of 2010, a \$39.3 million period-to-period decrease. Pipeline transportation volumes for the refined products business decreased to 638 MBPD during the first six months of 2011 from 698 MBPD during the first six months of 2010. Gross operating margin from our Products Pipeline System decreased \$34.7 million period-to-period primarily due to lower throughput volumes and higher operating expenses during the first six months of 2011 compared to the first six months of 2010. Equity earnings from our investment in Centennial decreased \$3.7 million period-to-period primarily due to lower transportation volumes. Net to our interest, transportation volumes on the Centennial pipeline decreased 13 MBPD period-to-period. Gross operating margin from the marketing of refined products decreased \$0.9 million period-to-period.

Of the total period-to-period decrease in gross operating margin from the Products Pipeline System, we estimate that \$13.7 million is due to lower revenues and higher operating expenses attributable to the impact of a pipeline leak that occurred in New York state in the third quarter of 2010. Following our repair of the leak, the affected segment of pipe was tested and returned to service in February 2011. The remaining \$21.0 million period-to-period decrease in gross operating margin from our Products Pipeline System is primarily due to lower volumes originating on the Gulf Coast for delivery to Midwest and Northeast U.S. markets and higher operating costs such as expenses for maintenance and pipeline integrity projects.

Gross operating margin from marine transportation and other services was \$28.0 million for the first six months of 2011 compared to \$31.6 million for the first six months of 2010, a \$3.6 million period-to-period decrease. Gross operating margin from marine transportation decreased \$7.1 million period-to-period primarily due to higher operating expenses. Gross operating margin from other services increased \$3.5 million period-to-period primarily due to our acquisition of trucking operations from EPCO in September 2010.

Other Investments. Our equity earnings from Energy Transfer Equity were \$9.0 million for the first six months of 2011 compared to \$4.9 million for the first six months of 2010, a \$4.1 million period-to-period increase. According to financial statements filed with the SEC, Energy Transfer Equity reported operating income of \$624.8 million for the first six months of 2011 compared to \$518.2 million for the first six months of 2010. The \$106.6 million period-to-period increase in Energy Transfer Equity's operating income is primarily due to earnings generated from recently acquired businesses and newly constructed assets, principally a NGL storage, fractionation and transportation business acquired in May 2011 and ETP's Tiger pipeline that was placed into service in December 2010. Collectively, other income and expense items for Energy Transfer Equity added a net \$21.5 million to earnings period-to-period primarily due to improved earnings from non-hedged interest rate derivatives of \$40.3 million, higher equity earnings from unconsolidated affiliates of \$35.9 million due to acquisitions and the first six months of 2010 including an impairment charge of \$52.6 million related to an unconsolidated affiliate, all of which was partially offset by a \$98.7 million period-to-period increase in interest expense. Our equity income from this investment was reduced by \$17.5

million and \$18.3 million of excess cost amortization during the first six months of 2011 and 2010, respectively.

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Liquidity and Capital Resources

At June 30, 2011, we had \$2.24 billion of liquidity, which is defined as unrestricted cash on hand plus available borrowing capacity under our consolidated revolving credit facilities, including \$382.5 million of available borrowing capacity under Duncan Energy Partners' revolving credit facility. Our primary cash requirements are for routine operating expenses, debt service, working capital, capital expenditures, business combinations and distributions to partners. We expect to fund our short-term cash requirements for operating expenses and sustaining capital expenditures using operating cash flows and borrowings under revolving credit facilities. Our expenditures for long-term productive assets (e.g., business expansion projects and acquisitions) are expected to be funded by a variety of sources (either separately or in combination) including the use of operating cash flows, borrowings under credit facilities, proceeds from the issuance of additional equity and debt securities and divestitures. We expect to fund cash distributions to partners primarily with operating cash flows. Our debt service requirements are expected to be funded by operating cash flows and/or refinancing arrangements. It is our belief that we will continue to have adequate liquidity and capital resources to fund expected recurring operating and investing activities.

We had approximately \$14.29 billion of principal amounts outstanding under consolidated debt agreements at June 30, 2011. In January 2011, EPO issued an aggregate of \$1.5 billion in principal amount of senior unsecured notes. EPO issued \$750.0 million in principal amount of 5-year senior unsecured notes ("Senior Notes AA") at 99.901% of their principal amount and \$750.0 million in principal amount of 30-year senior unsecured notes ("Senior Notes BB") at 99.317% of their principal amount. Net proceeds from the issuance of Senior Notes AA and BB were used (i) to repay \$450.0 million in aggregate principal amount of Senior Notes B that matured in February 2011, (ii) to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and (iii) for general company purposes. For additional information regarding our consolidated debt obligations, see Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

We may issue additional equity or debt securities to assist us in meeting our future liquidity and capital spending requirements. In July 2010, Enterprise, including EPO, filed a universal shelf registration statement (the "2010 Shelf") with the SEC. The 2010 Shelf allows Enterprise and EPO (on a standalone basis) to issue an unlimited amount of equity and debt securities, respectively. In January 2011, EPO utilized the 2010 Shelf to issue its Senior Notes AA and BB.

Enterprise also has a registration statement on file with the SEC in connection with its distribution reinvestment plan ("DRIP"). After taking into account limited partner units issued under this registration statement through June 30, 2011, Enterprise may issue an additional 27,389,108 common units under its DRIP. The following table reflects the number of common units issued and the net cash proceeds received from Enterprise's DRIP during the six months ended June 30, 2011:

	Number of Common Units Issued	Net Cash Proceeds
February 2011 issuance	474,706	\$19.6
May 2011 issuance	551,058	21.9
Total	1,025,764	\$41.5

In May 2011, Enterprise's employee unit purchase plan ("EUPP") reached the maximum 1,200,000 common units permitted under the plan and was terminated. A total of 86,141 common units were issued in 2011 under the EUPP, which generated net cash proceeds of \$3.6 million.

Net cash proceeds received in 2011 from Enterprise's DRIP and EUPP were used to temporarily reduce borrowings outstanding under EPO's Multi-Year Revolving Credit Facility and for general partnership purposes.

We own noncontrolling limited partner interests in Energy Transfer Equity, which, at June 30, 2011, totaled 34,526,090 common units. Our equity investments are a part of our long-term business

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strategy; however, we may from time-to-time elect to divest of a portion of our equity investments in order to redeploy capital. In May 2011, we sold 4,450,000 Energy Transfer Equity common units for net cash proceeds of \$165.8 million and recorded a gain of \$5.4 million on the sale. In July 2011, we sold an additional 4,114,136 Energy Transfer Equity common units in two separate transactions for a combined \$167.7 million. Proceeds from these transactions were used for general partnership purposes, including the funding of capital expenditures. Following the July transactions, we own 30,411,954 Energy Transfer Equity common units representing approximately 13.6% of their common units outstanding.

After giving effect to the limited waivers described below, we were in compliance with the financial covenants of our consolidated debt agreements at June 30, 2011.

Duncan Energy Partners' revolving credit and term loan agreements include various operating and financial covenants, including provisions for maintaining a leverage ratio (i.e., a debt to Consolidated Adjusted EBITDA ratio (as such terms are defined in the underlying lending agreements)) of less than 5.00x as of the last day of any fiscal quarter. Principally as a result of increased capital spending on the Haynesville Extension project and working capital needs, Duncan Energy Partners leverage ratio at June 30, 2011 was determined to be 5.04x, which (but for the waivers described below) would have exceeded the maximum leverage ratio allowed under its lending agreements. Duncan Energy Partners expects that its leverage ratio as of September 30, 2011 will also exceed 5.00x. However, after the Haynesville Extension enters full commercial operations (expected in the fourth quarter of 2011), Duncan Energy Partners anticipates that the ratio will be less than 5.00x as of December 31, 2011.

As a result of the foregoing, Duncan Energy Partners and its lenders entered into limited waiver agreements on June 30, 2011 with respect to the quarterly leverage ratio covenant. The leverage ratio covenant is waived for the fiscal quarters ending June 30, 2011 and September 30, 2011. The limited waiver agreements will provide Duncan Energy Partners additional financial flexibility in light of its capital spending requirements for the Haynesville Extension natural gas pipeline project. If the proposed merger with Duncan Energy Partners is approved, we expect to refinance its debt on terms customary with our other credit facilities.

Credit Ratings

At August 9, 2011, the investment-grade credit ratings of EPO's senior unsecured debt securities were: Baa3 from Moody's Investor Services ("Moody's"); BBB- from Fitch Ratings; and BBB- from Standard and Poor's. In March 2011, Moody's reaffirmed its corporate credit rating of EPO and revised its outlook for EPO's business from "stable" to "positive." On August 1, 2011, Fitch Ratings reaffirmed its corporate credit rating of EPO and revised its outlook for EPO's business from "stable" to "positive." EPO's credit ratings reflect only the view of a rating agency and should not be interpreted as a recommendation to buy, sell or hold any of our securities. A credit rating can be revised upward or downward or withdrawn at any time by a rating agency, if it determines that circumstances warrant such a change. A credit rating from one rating agency should be evaluated independently of credit ratings from other rating agencies.

A downgrade of EPO's credit ratings could result in us posting financial collateral in connection with our guaranty of Centennial's debt, which was \$53.2 million at June 30, 2011. Furthermore, we may enter into contracts in connection with our commodity and interest rate hedging activities that may require the posting of financial collateral if EPO's credit ratings were downgraded below investment grade.

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Cash Flows from Operating, Investing and Financing Activities

The following table summarizes our consolidated cash flows from operating, investing and financing activities for the periods presented (dollars in millions). For information regarding the individual components of our cash flow amounts, please refer to the Unaudited Condensed Statements of Consolidated Cash Flows included under Item 1 of this quarterly report.

	For the Six Months Ended June 30,	
	2011	2010
Net cash flows provided by operating activities	\$1,754.5	\$920.4
Cash used in investing activities	1,492.2	1,891.8
Cash provided by (used in) financing activities	(218.7)	1,412.5

Net cash flows provided by operating activities are largely dependent on earnings from our consolidated business activities. As a result, these cash flows are exposed to certain risks. We operate predominantly in the midstream energy industry. We provide products and services to producers and consumers of natural gas, NGLs, crude oil, refined products and certain petrochemicals. The products that we process, sell or transport are principally used as fuel for residential, agricultural and commercial heating; as feedstocks in petrochemical manufacturing; and in the production of motor gasoline. Reduced demand for our services or products by industrial customers, whether because of a decline in general economic conditions, reduced demand for the end products made with our products, or increased competition from other service providers or producers due to pricing differences or other reasons, could have a negative impact on our earnings and operating cash flows. For a more complete discussion of these and other risk factors pertinent to our business, see “Risk Factors” under Item 1A of our 2010 Form 10-K.

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

Comparison of Six Months Ended June 30, 2011 with Six Months Ended June 30, 2010

Operating Activities. The \$834.1 million increase in net cash flows provided by operating activities was primarily due to the following:

- § Net cash flows from consolidated operations (excluding cash distributions received from unconsolidated affiliates and cash payments for interest) increased \$875.0 million period-to-period. The increase in operating cash flow is generally due to increased profitability and the timing of related cash receipts and disbursements.
- § Cash payments for interest increased \$24.4 million period-to-period primarily due to an increase in debt obligations. Our average debt principal outstanding was \$14.18 billion during the six months ended June 30, 2011 compared to \$12.72 billion during the six months ended June 30, 2010.
- § Distributions received from unconsolidated affiliates decreased \$16.5 million period-to-period primarily due to reduced distributions from Seaway, Poseidon and Skelly-Belvie Pipeline Company, L.L.C.

Investing Activities. The \$399.6 million decrease in cash used for investing activities was primarily due to the following:

- § Capital spending for property, plant and equipment, net of contributions in aid of construction costs, increased \$971.7 million period-to-period primarily due to our Eagle Ford Shale and Haynesville Shale expansion projects. For additional information related to our capital spending program, see “Liquidity and Capital Resources –

Capital Spending” included within this Item 2.

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§ Restricted cash related to our hedging activities increased \$17.5 million (a cash outflow) during the six months ended June 30, 2011 due to increases in the margin requirements of our commodity hedging positions. During the six months ended June 30, 2010, restricted cash related to our hedging activities decreased \$52.6 million (a cash inflow) due to decreases in such margin requirements.

§ Cash used for business combinations decreased \$1.22 billion period-to-period, primarily due to the acquisition of the State Line and Fairplay natural gas gathering systems for approximately \$1.2 billion in May 2010.

§ Proceeds from asset sales and related transactions increased \$226.4 million period-to-period, primarily from sales of certain marine assets and a non-strategic NGL fractionation facility during the first quarter of 2011 and the sale of 4.45 million Energy Transfer Equity common units for \$165.8 million in May 2011.

Financing Activities. Cash used in financing activities was \$218.7 million for the six months ended June 30, 2011 compared to cash provided by financing activities of \$1.41 billion for the six months ended June 30, 2010.

As discussed under “Basis of Financial Statement Presentation” within this Item 2, the financial statements of Enterprise prior to the Holdings Merger were those of Holdings. As a result, cash distributions paid to partners for the six months ended June 30, 2010 represent payments to the former unitholders of Holdings whereas cash distributions paid to partners for the six months ended June 30, 2011 represent payments to the unitholders of Enterprise. Also, cash distributions paid to noncontrolling interest for six months ended June 30, 2010 include cash payments to the unitholders of Enterprise (other than Holdings). Cash contributions from noncontrolling interest for the six months ended June 30, 2010 primarily represent proceeds from Enterprise’s equity offerings (other than purchases by Holdings).

In general, the \$1.63 billion period-to-period change in cash flows from financing activities was primarily due to the following:

§ Net borrowings under our consolidated debt agreements decreased \$579.6 million period-to-period. This decrease was primarily due to EPO issuing \$1.5 billion in senior notes (Senior Notes AA and BB) and repaying its \$450 million Senior Notes B during the first quarter of 2011 compared to the issuance of \$2.0 billion in senior notes (Senior Notes X, Y and Z) in the second quarter of 2010.

§ Cash distributions to partners and noncontrolling interest were a combined \$1.0 billion for the six months ended June 30, 2011 compared to \$870.1 million for the six months ended June 30, 2010. The increase in cash distributions is primarily due to an increase in the number of distribution-bearing common units outstanding and the quarterly distribution rates of Enterprise.

§ Cash contributions from noncontrolling interest were \$2.6 million for the six months ended June 30, 2011 compared to \$961.9 million for the six months ended June 30, 2010. The issuance of common units by Enterprise (other than to Holdings) during the six months ended June 30, 2010 generated \$960.0 million of net cash proceeds. Net cash proceeds from the issuance of Enterprise common units during the six months ended June 30, 2011 were \$45.1 million.

Capital Spending

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

Shale and Eagle Ford Shale producing regions.

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

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

	For the Six Months Ended June 30,	
	2011	2010
Capital spending for property, plant and equipment, net of contributions in aid of construction costs	\$1,709.8	\$738.1
Capital spending for business combinations	--	1,220.2
Capital spending for intangible assets	3.6	--
Capital spending for investments in unconsolidated affiliates	11.8	10.2
Total capital spending	\$1,725.2	\$1,968.5

Based on information currently available, we estimate our consolidated capital spending for the remainder of 2011 will be approximately \$2.23 billion, which includes estimated expenditures of \$2.1 billion for growth capital projects and \$130 million for sustaining capital expenditures.

The preceding forecast of consolidated capital expenditures is based on our announced strategic operating and growth plans, which are dependent upon our ability to generate the required funds from either operating cash flows or other means, including borrowings under debt agreements, issuance of additional debt and equity securities, and potential divestitures. We may revise our forecast of capital spending due to factors beyond our control, such as weather related issues, changes in supplier prices or adverse economic conditions. Furthermore, our forecast of capital spending may change as a result of decisions made by management at a later date, which may include the addition of costs associated with unforeseen acquisition opportunities.

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

At June 30, 2011, we had approximately \$1.38 billion in purchase commitments outstanding that relate to our capital spending for property, plant and equipment. These commitments primarily relate to construction projects involving natural gas pipeline projects in the Eagle Ford Shale and Haynesville Shale.

Pipeline Integrity Costs

Our pipelines are subject to safety programs administered by the U.S. Department of Transportation (“DOT”). This federal agency has issued safety regulations containing requirements for the development of integrity management programs for hazardous liquid pipelines (e.g., NGL, crude oil, refined products and petrochemical pipelines) and natural gas pipelines. In general, these regulations require companies to assess the condition of their pipelines in certain high consequence areas (as defined by the regulation) and to perform any necessary repairs.

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The following table summarizes our pipeline integrity costs, including those attributable to DOT regulations, for the periods presented (dollars in millions):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
Expensed	\$14.1	\$10.0	\$21.8	\$19.4
Capitalized	16.0	10.8	26.7	13.5
Total	\$30.1	\$20.8	\$48.5	\$32.9

We expect the cost of our pipeline integrity program, irrespective of whether such costs are capitalized or expensed, to approximate \$69.0 million for the remainder of 2011. The cost of our pipeline integrity program was \$79.8 million for the year ended December 31, 2010.

Critical Accounting Policies and Estimates

A discussion of our critical accounting policies and estimates is included in our 2010 Form 10-K. The following estimates, in our opinion, are subjective in nature, require the exercise of professional judgment and involve complex analysis:

- § depreciation methods and estimated useful lives of property, plant and equipment;
- § measuring recoverability of long-lived assets and equity method investments;
- § amortization methods and estimated useful lives of qualifying intangible assets;
- § methods we employ to measure the fair value of goodwill;
- § revenue recognition policies and the use of estimates when recording revenue and expense accruals;
- § reserves for environmental matters and litigation contingencies; and
- § natural gas imbalances.

When used in the preparation of our consolidated financial statements, such estimates are based on our current knowledge and understanding of the underlying facts and circumstances and may be revised as a result of actions we take in the future. Changes in these estimates will occur as a result of the passage of time and the occurrence of future events. Subsequent changes in these estimates may have a significant impact on our consolidated financial position, results of operations and cash flows.

Recent Accounting Developments

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

Other Items

Contractual Obligations

With the exception of (i) routine fluctuations in the balance of our consolidated revolving credit facilities, (ii) the issuance of Senior Notes AA and BB in January 2011 and (iii) the repayment of Senior Notes B in February 2011, there have been no significant changes in our contractual obligations since those reported in our 2010 Form 10-K. For additional information regarding our consolidated debt obligations, see Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Insurance Matters

We participate as a named insured in EPCO's insurance program, which provides us with property damage, business interruption and other insurance 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

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adequate insurance coverage on our behalf, insurance may not fully cover every type of damage, interruption or other loss that might occur. If we were to incur a significant loss for which we were not fully insured, it could have a material impact on our financial position, results of operations and cash flows. In addition, there may be a timing difference between amounts we are required to pay in connection with a loss and amounts we receive from insurance as reimbursement. Any event that materially interrupts the revenues generated by our consolidated operations, or other losses that require us to make material 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.

For additional information regarding insurance matters, see Note 15 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

See “Significant Recent Developments” for information regarding a February 2011 NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility.

Non-GAAP Reconciliations

The following table presents a reconciliation of total segment gross operating margin to operating income and further to income before provision for income taxes for the periods presented (dollars in millions):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010
Total segment gross operating margin	\$922.5	\$809.0	\$1,797.9	\$1,615.0
Adjustments to reconcile total segment gross operating margin to operating income:				
Depreciation, amortization and accretion in operating costs and expenses	(233.3)	(227.0)	(464.1)	(439.4)
Non-cash asset impairment charges	--	--	--	(1.5)
Operating lease expenses paid by EPCO	(0.1)	(0.1)	(0.3)	(0.3)
Gains (losses) from asset sales and related transactions in operating costs and expenses	5.2	(1.7)	23.6	5.6
General and administrative costs	(50.4)	(40.5)	(88.3)	(80.8)
Operating income	643.9	539.7	1,268.8	1,098.6
Other expense, net	(188.0)	(178.8)	(371.3)	(336.6)
Income before provision for income taxes	\$455.9	\$360.9	\$897.5	\$762.0

Off-Balance Sheet Arrangements

In March 2011, Evangeline made the final scheduled payment of \$3.2 million on its subordinated note payable. Following this payment, Evangeline no longer has any debt obligations.

In April 2011, we refinanced the Poseidon revolving credit facility. The new replacement facility matures in April 2015 and has a borrowing capacity of \$125 million. At June 30, 2011, the principal amount outstanding under the Poseidon revolving credit facility was \$92.0 million.

Except for the matters noted above, there have been no other significant changes in our off-balance sheet arrangements since those reported in our 2010 Form 10-K.

Regulatory Matters

For information about regulatory risks involving climate change and greenhouse gas emissions, see Note 14 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Related Party Transactions

On April 28, 2011, we, our general partner and two of our subsidiaries entered into a definitive merger agreement with Duncan Energy Partners and DEP GP. See “Significant Recent Developments”

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within this Item 2 for information regarding the proposed merger of Duncan Energy Partners with a subsidiary of Enterprise. For additional information regarding our related party transactions, see Note 12 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Item 1 of this quarterly report.

Item 3. Quantitative and Qualitative Disclosures about Market Risk.

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

Our exposures to market risk have not changed materially since those reported under Item 7A, “Quantitative and Qualitative Disclosures About Market Risk,” included in our 2010 Form 10-K.

We assess the risk of each of our derivative instrument portfolios using a sensitivity analysis model. The sensitivity analysis applied to each portfolio measures the potential income or loss (i.e., the change in fair value of the derivative instrument portfolio) based upon a hypothetical 10% movement in the underlying interest rates or quoted market prices (as applicable) at the dates indicated. In addition to these variables, the fair value of each portfolio is influenced by fluctuations in the notional amounts of the instruments and the discount rates used to determine the present values.

The calculated results of the sensitivity analysis model do not reflect the impact that the same hypothetical price movement would have on the hedged exposures to which they relate. Therefore, the impact on the fair value of a derivative instrument resulting from a change in interest rates or quoted market prices (as applicable) would normally be offset by a corresponding gain or loss on the hedged debt instrument, inventory value or forecasted transaction assuming: (i) the derivative instrument functions effectively as a hedge of the underlying risk, (ii) the derivative instrument is not closed out in advance of its expected term; and (iii) the hedged forecasted transaction occurs within the expected time period. When considering that the majority of our derivative portfolios are designated as hedges, the sensitivities presented in the quantitative disclosures would most often be expected to have corresponding offsets.

We routinely review the effectiveness of our derivative instrument portfolios in light of current market conditions. If changes in market conditions or exposures warrant, the nature and volume of derivative instruments may change depending on the specific exposures being managed.

Interest Rate Derivative Instruments

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

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The following table summarizes our portfolio of interest rate swaps outstanding at June 30, 2011 reflected as fair value hedges or mark-to-market instruments:

Hedged Transaction	Number and Type of Derivative(s) Employed	Notional Amount	Period of Hedge	Rate Swap	Accounting Treatment
Senior Notes C	1 fixed-to-floating swap	\$100.0	1/04 to 2/13	6.4% to 2.3%	Fair value hedge
Senior Notes G	3 fixed-to-floating swaps	\$300.0	10/04 to 10/14	5.6% to 1.4%	Fair value hedge
Senior Notes P	7 fixed-to-floating swaps	\$400.0	6/09 to 8/12	4.6% to 2.7%	Fair value hedge
Senior Notes AA	10 fixed-to-floating swaps	\$750.0	1/11 to 2/16	3.2% to 1.2%	Fair value hedge
Non-Hedged Swaps	2 floating-to-fixed swaps	\$250.0	9/07 to 8/11	0.3% to 4.8%	Mark-to-market
Non-Hedged Swaps	6 floating-to-fixed swaps	\$600.0	5/10 to 7/14	0.3% to 2.0%	Mark-to-market

The following table summarizes our portfolio of forward starting interest rate swaps outstanding at June 30, 2011. The purpose of these derivative instruments (accounted for as cash flow hedges) is to 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	10 forward starting swaps	\$500.0	2/12	4.5%	Cash flow hedge
Future debt offering	5 forward starting swaps	\$250.0	8/12	3.9%	Cash flow hedge
Future debt offering	16 forward starting swaps	\$1,000.0	3/13	3.7%	Cash flow hedge

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

Scenario	Resulting Classification	Swap Fair Value at June 30, 2011	Swap Fair Value at July 19, 2011
FV assuming no change in underlying interest rates	Asset	\$51.3	\$63.7
FV assuming 10% increase in underlying interest rates	Asset	45.8	58.7
FV assuming 10% decrease in underlying interest rates	Asset	56.9	68.6

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

Scenario	Resulting Classification	Swap Fair Value at	
		June 30, 2011	July 19, 2011
FV assuming no change in underlying interest rates	Liability	\$(21.0)	\$(64.2)
FV assuming 10% increase in underlying interest rates	Asset (Liability)	33.6	(12.3)
FV assuming 10% decrease in underlying interest rates	Liability	(77.7)	(117.9)

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 such price risks, we enter into commodity derivative instruments such as physical forward agreements, futures contracts, fixed-for-float swaps, basis swaps and options contracts.

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 natural gas processing activities. We achieve this objective by using physical

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and financial instruments to lock in the purchase prices of natural gas consumed as PTR and the sales prices of the related NGL products. This program consists of (i) the forward sale of a portion of our expected equity NGL production at fixed prices through December 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.

At June 30, 2011, this program had hedged future estimated gross margins (before plant operating expenses) of \$378.1 million on 9.7 MMBbls of forecasted NGL forward sales transactions and equivalent PTR volumes extending through December 2011. At July 29, 2011, this program had hedged future estimated gross margins (before plant operating expenses) of \$404.0 million on 11.0 MMBbls of forecasted NGL forward sales transactions and equivalent PTR volumes extending through December 2011.

§ 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.

Certain basis swaps, basis spread options and other financial derivative instruments not designated as hedging instruments are used to manage market risks associated with anticipated purchases and sales of natural gas necessary to optimize our owned and contractually committed transportation and storage capacity.

There is some uncertainty involved in the timing of these transactions often due to the development of more favorable profit opportunities or when spreads are insufficient to cover variable costs thus reducing the likelihood that the transactions will occur as originally forecasted. As a result of this timing uncertainty, these derivative instruments do not qualify for hedge accounting even though they are effective at managing the risk exposures of these assets.

The earnings volatility caused by fluctuations in non-cash, mark-to-market earnings cannot be predicted and the impact to earnings could be material.

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The following table summarizes our commodity derivative instruments outstanding at June 30, 2011:

Derivative Purpose	Volume (1)		Accounting Treatment
	Current (2)	Long-Term (2)	
Derivatives designated as hedging instruments:			
Enterprise:			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction (“PTR”) (3)	31.9 Bcf	n/a	Cash flow hedge
Forecasted sales of NGLs (4)	6.6 MMBbbls	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchases of NGLs	0.1 MMBbbls	n/a	Cash flow hedge
Forecasted sales of octane enhancement products	2.0 MMBbbls	n/a	Cash flow hedge
Natural gas marketing:			
Natural gas storage inventory management activities	2.8 Bcf	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products	2.3 MMBbbls	n/a	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products	2.3 MMBbbls	n/a	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products	1.1 MMBbbls	n/a	Cash flow hedge
Forecasted sales of refined products	1.2 MMBbbls	n/a	Cash flow hedge
Crude oil marketing:			
Forecasted purchases of crude oil	1.1 MMBbbls	n/a	Cash flow hedge
Forecasted sales of crude oil	1.9 MMBbbls	n/a	Cash flow hedge
Derivatives not designated as hedging instruments:			
Enterprise:			
Natural gas risk management activities (5,6)	385.8 Bcf	69.0 Bcf	Mark-to-market
Refined products risk management activities (6)	3.4 MMBbbls	n/a	Mark-to-market
Crude oil risk management activities (6)	5.7 MMBbbls	n/a	Mark-to-market

Duncan Energy Partners:

Natural gas risk management activities (6)	0.2 Bcf	n/a	Mark-to-market
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(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 designated as cash flow hedges, derivatives designated as fair value hedges and derivatives not designated as hedging instruments is June 2012, January 2012 and December 2013, respectively.

(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) Forecasted sales of NGL volumes under Natural gas processing exclude 1.6 MMBbls of additional hedges executed under contracts that have been designated as normal sales agreements.

(5) Current and long-term volumes include approximately 75.5 Bcf and 2.8 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.

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

Scenario	Resulting Classification	Portfolio Fair Value at	
		June 30, 2011	July 19, 2011
FV assuming no change in underlying commodity prices	Liability	\$(0.7)	\$(3.7)
FV assuming 10% increase in underlying commodity prices	Liability	(5.9)	(9.2)
FV assuming 10% decrease in underlying commodity prices	Asset	4.4	1.8

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

Scenario	Resulting Classification	Portfolio Fair Value at June 30, 2011 July 19, 2011	
FV assuming no change in underlying commodity prices	Liability	\$(74.7)	\$(97.6)
FV assuming 10% increase in underlying commodity prices	Liability	(129.7)	(153.2)
FV assuming 10% decrease in underlying commodity prices	Liability	(19.7)	(41.9)

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

Scenario	Resulting Classification	Portfolio Fair Value at June 30, 2011 July 19, 2011	
FV assuming no change in underlying commodity prices	Asset	\$11.4	\$12.8
FV assuming 10% increase in underlying commodity prices	Asset	10.8	14.3
FV assuming 10% decrease in underlying commodity prices	Asset	12.1	11.3

Item 4. Controls and Procedures.

Disclosure Controls and Procedures

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

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

Changes in Internal Control over Financial Reporting

There were no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the second quarter of 2011, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

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

PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

For information regarding our litigation matters, see Note 14, “Commitments and Contingencies – Litigation,” of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report, which is incorporated herein by reference.

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Item 1A. Risk Factors.

Security holders and potential investors in our securities should carefully consider the risk factors set forth in our 2010 Form 10-K, in addition to other information in such annual report. The risk factors set forth in our 2010 Form 10-K are important factors that could cause our actual results to differ materially from those contained in any written or oral forward-looking statements made by us or on our behalf.

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

As of June 30, 2011, we and our affiliates could repurchase up to 618,400 additional common units under the December 1998 Common Unit Repurchase Program. We did not repurchase any of our common units in connection with this program during the six months ended June 30, 2011.

The following table summarizes our repurchase activity during 2011 in connection with other arrangements:

Period	Total Number of Units Purchased	Average Price Paid per Unit	Total Number of Units Purchased as Part of Publicly Announced Plans	Maximum Number of Units That May Yet Be Purchased Under the Plans
February 2011 (1)	91,126	\$ 43.00	--	--
May 2011 (2)	135,475	\$ 41.63	--	--

(1) Of the 336,227 restricted common units that vested in February 2011 and converted to common units, 91,126 units were sold back to us by employees to cover related withholding tax requirements.

(2) Of the 492,318 restricted common units that vested in May 2011 and converted to common units, 135,475 units were sold back to us by employees to cover related withholding tax requirements.

Item 3. Defaults Upon Senior Securities.

None.

Item 4. (Removed and Reserved).

Item 5. Other Information.

None.

Item 6. Exhibits.

Exhibit
Number

Exhibit*

- 2.1 Merger Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed December 15, 2003).
- 2.2 Amendment No. 1 to Merger Agreement, dated as of August 31, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed September 7, 2004).

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2.3	Parent Company Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.2 to Form 8-K filed December 15, 2003).
2.4	Amendment No. 1 to Parent Company Agreement, dated as of April 19, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.1 to Form 8-K filed April 21, 2004).
2.5	Purchase and Sale Agreement (Gas Plants), dated as of December 15, 2003, by and between El Paso Corporation, El Paso Field Services Management, Inc., El Paso Transmission, L.L.C., El Paso Field Services Holding Company and Enterprise Products Operating L.P. (incorporated by reference to Exhibit 2.4 to Form 8-K filed December 15, 2003).
2.6	Agreement and Plan of Merger, dated as of June 28, 2009, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Sub B LLC, TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed June 29, 2009).
2.7	Agreement and Plan of Merger, dated as of June 28, 2009, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Sub A LLC, TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (incorporated by reference to Exhibit 2.2 to Form 8-K filed June 29, 2009).
2.8	Agreement and Plan of Merger, dated as of September 3, 2010, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise ETE LLC, Enterprise GP Holdings L.P. and EPE Holdings, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed September 7, 2010).
2.9	Agreement and Plan of Merger, dated as of September 3, 2010, by and among Enterprise Products GP, LLC, Enterprise GP Holdings L.P. and EPE Holdings, LLC (incorporated by reference to Exhibit 2.2 to Form 8-K filed September 7, 2010).
2.10	Contribution Agreement, dated as of September 30, 2010, by and between Enterprise Products Company and Enterprise Products Partners L.P. (incorporated by reference to Exhibit 2.1 to Form 8-K filed October 1, 2010).
2.11	Agreement and Plan of Merger, dated as of April 28, 2011, by and among Enterprise Products Partners L.P., Enterprise Products Holdings LLC, EPD MergerCo LLC, Duncan Energy Partners L.P. and DEP Holdings, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed April 29, 2011).
3.1	Certificate of Limited Partnership of Enterprise Products Partners L.P. (incorporated by reference to Exhibit 3.6 to Form 10-Q filed November 9, 2007).
3.2	Certificate of Amendment to Certificate of Limited Partnership of Enterprise Products Partners L.P., filed on November 22, 2010 with the Delaware Secretary of State (incorporated by reference to Exhibit 3.6 to Form 8-K filed November 23, 2010).
3.3	Sixth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated November 22, 2010 (incorporated by reference to Exhibit 3.2 to Form 8-K filed November 23, 2010).
3.4	Certificate of Formation of EPE Holdings, LLC (incorporated by reference to Exhibit 3.3 to Form S-1/A Registration Statement, Reg. No. 333-124320, filed by Enterprise GP Holdings L.P. on July 22, 2005).
3.5	Certificate of Amendment to Certificate of Formation of EPE Holdings, LLC, filed on November 22, 2010 with the Delaware Secretary of State (incorporated by reference to Exhibit 3.5 to Form 8-K filed November 23, 2010).
3.6	Fourth Amended and Restated Limited Liability Company Agreement of EPE Holdings, LLC dated effective as of November 22, 2010 (incorporated by reference to Exhibit 3.3 to Form 8-K filed November 23, 2010).

- 3.7 First Amendment to Fourth Amended and Restated Limited Liability Company Agreement of EPE Holdings, LLC, dated effective as of November 23, 2010 (changing name to Enterprise Products Holdings LLC) (incorporated by reference to Exhibit 3.4 to Form 8-K filed November 23, 2010).

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3.8	Company Agreement of Enterprise Products Operating LLC dated June 30, 2007 (incorporated by reference to Exhibit 3.3 to Form 10-Q filed August 8, 2007).
3.9	Certificate of Incorporation of Enterprise Products OLPGP, Inc., dated December 3, 2003 (incorporated by reference to Exhibit 3.5 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
3.10	Bylaws of Enterprise Products OLPGP, Inc., dated December 8, 2003 (incorporated by reference to Exhibit 3.6 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
4.1	Form of Common Unit certificate (incorporated by reference to Exhibit 4.1 to Form S-1/A Registration Statement, Reg. No. 333-52537, filed July 21, 1998).
4.2	Indenture, dated as of March 15, 2000, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed March 10, 2000).
4.3	First Supplemental Indenture, dated as of January 22, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.4	Second Supplemental Indenture, dated as of February 14, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 10-K filed March 31, 2003).
4.5	Third Supplemental Indenture, dated as of June 30, 2007, among Enterprise Products Operating L.P., as Original Issuer, Enterprise Products Partners L.P., as Parent Guarantor, Enterprise Products Operating LLC, as New Issuer, and U.S. Bank National Association, as successor Trustee (incorporated by reference to Exhibit 4.55 to Form 10-Q filed August 8, 2007).
4.6	Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed October 6, 2004).
4.7	First Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed October 6, 2004).
4.8	Second Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 6, 2004).
4.9	Third Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed October 6, 2004).
4.10	Fourth Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 6, 2004).
4.11	Fifth Supplemental Indenture, dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed March 3, 2005).
4.12	Sixth Supplemental Indenture, dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed March 3, 2005).
4.13	Seventh Supplemental Indenture, dated as of June 1, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.46 to Form 10-Q filed November 4, 2005).

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4.14	Eighth Supplemental Indenture, dated as of July 18, 2006, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006).
4.15	Ninth Supplemental Indenture, dated as of May 24, 2007, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed May 24, 2007).
4.16	Tenth Supplemental Indenture, dated as of June 30, 2007, among Enterprise Products Operating L.P., as Original Issuer, Enterprise Products Partners L.P., as Parent Guarantor, Enterprise Products Operating LLC, as New Issuer, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.54 to Form 10-Q filed August 8, 2007).
4.17	Eleventh Supplemental Indenture, dated as of September 4, 2007, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed September 5, 2007).
4.18	Twelfth Supplemental Indenture, dated as of April 3, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed April 3, 2008).
4.19	Thirteenth Supplemental Indenture, dated as of April 3, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed April 3, 2008).
4.20	Fourteenth Supplemental Indenture, dated as of December 8, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed December 8, 2008).
4.21	Fifteenth Supplemental Indenture, dated as of June 10, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed June 10, 2009).
4.22	Sixteenth Supplemental Indenture, dated as of October 5, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.23	Seventeenth Supplemental Indenture, dated as of October 27, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed October 28, 2009).
4.24	Eighteenth Supplemental Indenture, dated as of October 27, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed October 28, 2009).
4.25	Nineteenth Supplemental Indenture, dated as of May 20, 2010, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed May 20, 2010).
4.26	Twentieth Supplemental Indenture, dated as of January 13, 2011, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed January 13, 2011).
4.27	Global Note representing \$350.0 million principal amount of 6.375% Series B Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.28	Global Note representing \$499.2 million principal amount of 6.875% Series B Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 10-K filed March 31, 2003).

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4.29	Global Notes representing \$450.0 million principal amount of 7.50% Senior Notes due 2011 (incorporated by reference to Exhibit 4.1 to Form 8-K filed January 25, 2001).
4.30	Global Note representing \$500.0 million principal amount of 5.60% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.17 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005).
4.31	Global Note representing \$150.0 million principal amount of 5.60% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.18 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005).
4.32	Global Note representing \$350.0 million principal amount of 6.65% Series B Senior Notes due 2034 with attached Guarantee (incorporated by reference to Exhibit 4.19 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005).
4.33	Global Note representing \$250.0 million principal amount of 5.00% Series B Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.31 to Form 10-Q filed November 4, 2005).
4.34	Global Note representing \$250.0 million principal amount of 5.75% Series B Senior Notes due 2035 with attached Guarantee (incorporated by reference to Exhibit 4.32 to Form 10-Q filed November 4, 2005).
4.35	Global Note representing \$500.0 million principal amount of 4.95% Senior Notes due 2010 with attached Guarantee (incorporated by reference to Exhibit 4.47 to Form 10-Q filed November 4, 2005).
4.36	Form of Junior Subordinated Note, including Guarantee (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006).
4.37	Global Note representing \$800.0 million principal amount of 6.30% Senior Notes due 2017 with attached Guarantee (incorporated by reference to Exhibit 4.38 to Form 10-Q filed November 9, 2007).
4.38	Form of Global Note representing \$400.0 million principal amount of 5.65% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed April 3, 2008).
4.39	Form of Global Note representing \$700.0 million principal amount of 6.50% Senior Notes due 2019 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed April 3, 2008).
4.40	Form of Global Note representing \$500.0 million principal amount of 9.75% Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed December 8, 2008).
4.41	Form of Global Note representing \$500.0 million principal amount of 4.60% Senior Notes due 2012 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed June 10, 2009).
4.42	Form of Global Note representing \$500.0 million principal amount of 5.25% Senior Notes due 2020 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.43	Form of Global Note representing \$600.0 million principal amount of 6.125% Senior Notes due 2039 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.44	Form of Global Note representing \$490.5 million principal amount of 7.625% Senior Notes due 2012 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 28, 2009).
4.45	Form of Global Note representing \$182.6 million principal amount of 6.125% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed October 28, 2009).
4.46	Form of Global Note representing \$237.6 million principal amount of 5.90% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 28, 2009).
4.47	Form of Global Note representing \$349.7 million principal amount of 6.65% Senior Notes due 2018 with attached Guarantee (incorporated by reference to Exhibit 4.6 to Form 8-K filed October 28, 2009).

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4.48	Form of Global Note representing \$399.6 million principal amount of 7.55% Senior Notes due 2038 with attached Guarantee (incorporated by reference to Exhibit 4.7 to Form 8-K filed October 28, 2009).
4.49	Form of Global Note representing \$285.8 million principal amount of 7.000% Junior Subordinated Notes due 2067 with attached Guarantee (incorporated by reference to Exhibit 4.8 to Form 8-K filed October 28, 2009).
4.50	Form of Global Note representing \$400.0 million principal amount of 3.70% Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed May 20, 2010).
4.51	Form of Global Note representing \$1.0 billion principal amount of 5.20% Senior Notes due 2020 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed May 20, 2010).
4.52	Form of Global Note representing \$600.0 million principal amount of 6.45% Senior Notes due 2040 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed May 20, 2010).
4.53	Form of Global Note representing \$750.0 million principal amount of 3.20% Senior Notes due 2016 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed January 13, 2011).
4.54	Form of Global Note representing \$750.0 million principal amount of 5.95% Senior Notes due 2041 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed January 13, 2011).
4.55	Replacement Capital Covenant, dated May 24, 2007, executed by Enterprise Products Operating L.P. and Enterprise Products Partners L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 99.1 to Form 8-K filed May 24, 2007).
4.56	First Amendment to Replacement Capital Covenant dated August 25, 2006, executed by Enterprise Products Operating L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 99.2 to Form 8-K filed August 25, 2006).
4.57	Replacement Capital Covenant, dated October 27, 2009, among Enterprise Products Operating LLC and Enterprise Products Partners L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 4.9 to Form 8-K filed October 28, 2009).
4.58	Indenture, dated February 20, 2002, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as Subsidiary Guarantors, and First Union National Bank, NA, as Trustee (incorporated by reference to Exhibit 99.2 to the Form 8-K filed by TEPPCO Partners, L.P. on February 20, 2002).
4.59	First Supplemental Indenture, dated February 20, 2002, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as Subsidiary Guarantors, and First Union National Bank, NA, as Trustee (incorporated by reference to Exhibit 99.3 to the Form 8-K filed by TEPPCO Partners, L.P. on February 20, 2002).
4.60	Second Supplemental Indenture, dated June 27, 2002, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as Initial Subsidiary Guarantors, Val Verde Gas Gathering Company, L.P., as New Subsidiary Guarantor, and Wachovia Bank, National Association, formerly known as First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.6 to the Form 10-Q filed by TEPPCO Partners, L.P. on August 14, 2002).
4.61	Third Supplemental Indenture, dated January 20, 2003, by and among TEPPCO Partners, L.P. as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Jonah Gas Gathering Company and Val Verde Gas Gathering Company, L.P. as Subsidiary Guarantors, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.7 to the Form 10-K filed by TEPPCO Partners, L.P. on March 21, 2003).
4.62	Full Release of Guarantee, dated July 31, 2006, by Wachovia Bank, National Association, as Trustee, in favor of Jonah Gas Gathering Company (incorporated by reference to Exhibit 4.8 to the Form 10-Q filed by TEPPCO Partners, L.P. on November 7, 2006).

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- 4.63 Fourth Supplemental Indenture, dated June 30, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Val Verde Gas Gathering Company, L.P., TE Products Pipeline Company, LLC and TEPPCO Midstream Companies, LLC, as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.3 to the Form 8-K filed by TE Products Pipeline Company, LLC on July 6, 2007).
- 4.64 Fifth Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.11 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008).
- 4.65 Sixth Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.12 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008).
- 4.66 Seventh Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.13 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008).
- 4.67 Eighth Supplemental Indenture, dated October 27, 2009, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.1 to the Form 8-K filed by TEPPCO Partners, L.P. on October 28, 2009).
- 4.68 Full Release of Guarantee, dated November 23, 2009, of TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P. by U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.64 to Form 10-K filed on March 1, 2010).
- 4.69 Indenture, dated May 14, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 99.1 of the Form 8-K filed by TEPPCO Partners, L.P. on May 15, 2007).
- 4.70 First Supplemental Indenture, dated May 18, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TEPPCO Partners, L.P. on May 18, 2007).
- 4.71 Replacement of Capital Covenant, dated May 18, 2007, executed by TEPPCO Partners, L.P., TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P. in favor of the covered debt holders described therein (incorporated by reference to Exhibit 99.1 to the Form 8-K of TEPPCO Partners, L.P. on May 18, 2007).
- 4.72 Second Supplemental Indenture, dated as of June 30, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Existing Subsidiary Guarantors, TE Products Pipeline Company, LLC and TEPPCO Midstream Companies, LLC, as New Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to

Exhibit 4.2 to the Form 8-K filed by TE Products Pipeline Company, LLC on July 6, 2007).

- 4.73 Third Supplemental Indenture, dated as of October 27, 2009, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TEPPCO Partners, L.P. on October 28, 2009).

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4.74	Full Release of Guarantee, dated as of November 23, 2009, of TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P. by The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.70 to Form 10-K filed on March 1, 2010).
10.1	Voting Agreement, dated as of April 28, 2011, by and among Duncan Energy Partners L.P. Enterprise Products Partners L.P. and Enterprise GTM Holdings L.P. (incorporated by reference to Exhibit 10.1 to Form 8-K filed April 29, 2011).
12.1#	Computation of ratio of earnings to fixed charges for the six months ended June 30, 2011 and for each of the four years ended December 31, 2010, 2009, 2008 and 2007.
31.1#	Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise Products Partners L.P. for the June 30, 2011 quarterly report on Form 10-Q.
31.2#	Sarbanes-Oxley Section 302 certification of W. Randall Fowler for Enterprise Products Partners L.P. for the June 30, 2011 quarterly report on Form 10-Q.
32.1#	Section 1350 certification of Michael A. Creel for the June 30, 2011 quarterly report on Form 10-Q.
32.2#	Section 1350 certification of W. Randall Fowler for the June 30, 2011 quarterly report on Form 10-Q.
101.CAL#	XBRL Calculation Linkbase Document
101.DEF#	XBRL Definition Linkbase Document
101.INS#	XBRL Instance Document
101.LAB#	XBRL Labels Linkbase Document
101.PRE#	XBRL Presentation Linkbase Document
101.SCH#	XBRL Schema Document

* With respect to any exhibits incorporated by reference to any Exchange Act filings, the Commission file numbers for Enterprise Products Partners L.P., Enterprise GP Holdings L.P, TEPPCO Partners, L.P. and TE Products Pipeline Company, LLC are 1-14323, 1-32610, 1-10403 and 1-13603, respectively.

Filed with this report.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on August 9, 2011.

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

By: Enterprise Products Holdings LLC, as
General Partner

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