

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 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, 2013

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 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

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

Accelerated filer

Smaller reporting company

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

Yes No

There were 915,422,738 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, 2013. Our common units trade on the New York Stock Exchange under the ticker symbol "EPD."

**ENTERPRISE PRODUCTS PARTNERS L.P.
TABLE OF CONTENTS**

		<u>Page No.</u>
PART I. FINANCIAL INFORMATION.		
Item 1.	Financial Statements.	
	Unaudited Condensed Consolidated Balance Sheets	2
	Unaudited Condensed Statements of Consolidated Operations	3
	Unaudited Condensed Statements of Consolidated Comprehensive Income	4
	Unaudited Condensed Statements of Consolidated Cash Flows	5
	Unaudited Condensed Statements of Consolidated Equity	6
	Notes to Unaudited Condensed Consolidated Financial Statements:	
	1. Partnership Operations, Organization and Basis of Presentation	7
	2. General Accounting Matters	8
	3. Equity-based Awards	10
	4. Derivative Instruments, Hedging Activities and Fair Value Measurements	13
	5. Inventories	21
	6. Property, Plant and Equipment	22
	7. Investments in Unconsolidated Affiliates	24
	8. Intangible Assets and Goodwill	26
	9. Debt Obligations	28
	10. Equity and Distributions	30
	11. Business Segments	33
	12. Related Party Transactions	37
	13. Earnings Per Unit	38
	14. Commitments and Contingencies	39
	15. Insurance Matters	40
	16. Supplemental Cash Flow Information	40
	17. Condensed Consolidating Financial Information	41
Item 2.	Management's Discussion and Analysis of Financial Condition and Results of Operations.	49
Item 3.	Quantitative and Qualitative Disclosures about Market Risk.	72
Item 4.	Controls and Procedures.	75
PART II. OTHER INFORMATION.		
Item 1.	Legal Proceedings.	76
Item 1A.	Risk Factors.	76
Item 2.	Unregistered Sales of Equity Securities and Use of Proceeds.	76
Item 3.	Defaults Upon Senior Securities.	76
Item 4.	Mine Safety Disclosures.	76
Item 5.	Other Information.	77
Item 6.	Exhibits.	77
	Signatures	85

PART I. FINANCIAL INFORMATION.

Item 1. Financial Statements.

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

ASSETS	June 30, 2013	December 31, 2012
Current assets:		
Cash and cash equivalents	\$ 45.3	\$ 16.1
Restricted cash	26.3	4.3
Accounts receivable – trade, net of allowance for doubtful accounts of \$12.2 at June 30, 2013 and \$13.2 at December 31, 2012	4,651.5	4,350.9
Accounts receivable – related parties	19.8	2.5
Inventories	1,411.4	1,088.4
Prepaid and other current assets	425.7	380.9
Total current assets	6,580.0	5,843.1
Property, plant and equipment, net	25,566.1	24,846.4
Investments in unconsolidated affiliates	1,938.8	1,394.6
Intangible assets, net of accumulated amortization of \$1,098.0 at June 30, 2013 and \$1,050.0 at December 31, 2012	1,513.2	1,566.8
Goodwill	2,080.0	2,086.8
Other assets	198.8	196.7
Total assets	\$ 37,876.9	\$ 35,934.4
LIABILITIES AND EQUITY		
Current liabilities:		
Current maturities of debt (see Note 9)	\$ 540.0	\$ 1,546.6
Accounts payable – trade	777.4	764.5
Accounts payable – related parties	142.0	127.1
Accrued product payables	4,770.4	4,476.2
Accrued interest	303.6	300.8
Other current liabilities	339.7	540.5
Total current liabilities	6,873.1	7,755.7
Long-term debt (see Note 9)	16,429.6	14,655.2
Deferred tax liabilities	37.2	22.5
Other long-term liabilities	184.2	205.0
Commitments and contingencies (see Note 14)		
Equity: (see Note 10)		
Partners' equity:		
Limited partners:		
Common units (915,434,963 units outstanding at June 30, 2013 and 898,813,337 units outstanding at December 31, 2012)	14,400.4	13,439.6
Class B units (4,520,431 units outstanding at June 30, 2013 and December 31, 2012)	118.5	118.5
Total limited partners' equity	14,518.9	13,558.1
Accumulated other comprehensive loss	(363.0)	(370.4)
Total partners' equity	14,155.9	13,187.7
Noncontrolling interests	196.9	108.3
Total equity	14,352.8	13,296.0
Total liabilities and equity	\$ 37,876.9	\$ 35,934.4

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
Revenues:				
Third parties	\$ 11,142.6	\$ 9,764.2	\$ 22,519.8	\$ 20,985.9
Related parties	6.7	25.6	12.6	56.4
Total revenues (see Note 11)	11,149.3	9,789.8	22,532.4	21,042.3
Costs and expenses:				
Operating costs and expenses:				
Third parties	10,143.0	8,788.0	20,349.2	19,106.8
Related parties	224.2	221.5	438.4	369.9
Total operating costs and expenses	10,367.2	9,009.5	20,787.6	19,476.7
General and administrative costs:				
Third parties	17.5	16.7	37.2	40.3
Related parties	28.0	25.8	57.8	48.5
Total general and administrative costs	45.5	42.5	95.0	88.8
Total costs and expenses (see Note 11)	10,412.7	9,052.0	20,882.6	19,565.5
Equity in income of unconsolidated affiliates	37.6	11.3	82.1	21.2
Operating income	774.2	749.1	1,731.9	1,498.0
Other income (expense):				
Interest expense	(200.2)	(186.6)	(396.1)	(373.1)
Interest income	0.3	0.1	0.5	0.4
Other, net (see Note 2)	(0.6)	13.1	(0.9)	71.5
Total other expense, net	(200.5)	(173.4)	(396.5)	(301.2)
Income before income taxes	573.7	575.7	1,335.4	1,196.8
Benefit from (provision for) income taxes (see Note 2)	(20.4)	(8.5)	(26.8)	25.9
Net income	553.3	567.2	1,308.6	1,222.7
Net income attributable to noncontrolling interests (see Note 10)	(0.8)	(0.9)	(2.6)	(5.1)
Net income attributable to limited partners	\$ 552.5	\$ 566.3	\$ 1,306.0	\$ 1,217.6
Earnings per unit: (see Note 13)				
Basic earnings per unit	\$ 0.62	\$ 0.66	\$ 1.48	\$ 1.42
Diluted earnings per unit	\$ 0.60	\$ 0.64	\$ 1.43	\$ 1.37

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
Net income	\$ 553.3	\$ 567.2	\$ 1,308.6	\$ 1,222.7
Other comprehensive income (loss):				
Cash flow hedges:				
Commodity derivative instruments:				
Changes in fair value of cash flow hedges	34.1	105.0	(13.5)	45.4
Reclassification of gains and losses to net income	(7.2)	14.2	0.1	36.2
Interest rate derivative instruments:				
Changes in fair value of cash flow hedges	--	(84.0)	6.7	(55.1)
Reclassification of losses to net income	7.8	3.7	13.7	6.4
Total cash flow hedges	34.7	38.9	7.0	32.9
Change in funded status of pension and postretirement plans, net of tax	0.4	--	0.4	(1.2)
Proportionate share of other comprehensive income of unconsolidated affiliate	--	--	--	1.0
Change in fair value of available-for-sale equity securities	--	(15.8)	--	--
Total other comprehensive income	35.1	23.1	7.4	32.7
Comprehensive income	588.4	590.3	1,316.0	1,255.4
Comprehensive income attributable to noncontrolling interests	(0.8)	(0.9)	(2.6)	(5.1)
Comprehensive income attributable to limited partners	\$ 587.6	\$ 589.4	\$ 1,313.4	\$ 1,250.3

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

	For the Six Months Ended June 30,	
	2013	2012
Operating activities:		
Net income	\$ 1,308.6	\$ 1,222.7
<i>Reconciliation of net income to net cash flows provided by operating activities:</i>		
Depreciation, amortization and accretion	599.8	537.7
Non-cash asset impairment charges	38.1	14.5
Equity in income of unconsolidated affiliates	(82.1)	(21.2)
Distributions received from unconsolidated affiliates	119.3	50.5
Gains attributable to asset sales and insurance recoveries (see Note 16)	(58.2)	(100.3)
Deferred income tax expense (benefit)	14.8	(64.9)
Changes in fair market value of derivative instruments	(1.2)	(21.6)
Net effect of changes in operating accounts (see Note 16)	(409.2)	(280.3)
Other operating activities	1.0	1.2
Net cash flows provided by operating activities	<u>1,530.9</u>	<u>1,338.3</u>
Investing activities:		
Capital expenditures	(1,447.3)	(1,813.1)
Contributions in aid of construction costs	14.9	10.0
Decrease (increase) in restricted cash	(22.0)	38.5
Investments in unconsolidated affiliates	(547.9)	(125.5)
Proceeds from asset sales and insurance recoveries (see Note 16)	199.2	1,156.7
Other investing activities	0.5	(16.4)
Cash used in investing activities	<u>(1,802.6)</u>	<u>(749.8)</u>
Financing activities:		
Borrowings under debt agreements	7,064.5	2,414.6
Repayments of debt	(6,281.6)	(1,891.0)
Debt issuance costs	(23.7)	(7.5)
Monetization of interest rate derivative instruments (see Note 4)	(168.8)	(77.6)
Cash distributions paid to limited partners (see Note 10)	(1,171.9)	(1,068.6)
Cash distributions paid to noncontrolling interests	(4.7)	(8.1)
Cash contributions from noncontrolling interests (see Note 10)	95.9	5.9
Net cash proceeds from the issuance of common units	835.4	61.5
Acquisition of treasury units	(35.8)	(19.1)
Other financing activities	(8.4)	(3.9)
Cash provided by (used in) financing activities	<u>300.9</u>	<u>(593.8)</u>
Net change in cash and cash equivalents	<u>29.2</u>	<u>(5.3)</u>
Cash and cash equivalents, January 1	<u>16.1</u>	<u>19.8</u>
Cash and cash equivalents, June 30	<u>\$ 45.3</u>	<u>\$ 14.5</u>

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

	Partners' Equity			
	Limited Partners	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
Balance, December 31, 2012	\$ 13,558.1	\$ (370.4)	\$ 108.3	\$ 13,296.0
Net income	1,306.0	--	2.6	1,308.6
Cash distributions paid to limited partners	(1,171.9)	--	--	(1,171.9)
Cash distributions paid to noncontrolling interests	--	--	(4.7)	(4.7)
Cash contributions from noncontrolling interests	--	--	95.9	95.9
Net cash proceeds from the issuance of common units	835.4	--	--	835.4
Amortization of fair value of equity-based awards	35.6	--	--	35.6
Cash flow hedges	--	7.0	--	7.0
Other	(44.3)	0.4	(5.2)	(49.1)
Balance, June 30, 2013	\$ 14,518.9	\$ (363.0)	\$ 196.9	\$ 14,352.8

	Partners' Equity			
	Limited Partners	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
Balance, December 31, 2011	\$ 12,464.8	\$ (351.4)	\$ 105.9	\$ 12,219.3
Net income	1,217.6	--	5.1	1,222.7
Cash distributions paid to limited partners	(1,068.6)	--	--	(1,068.6)
Cash distributions paid to noncontrolling interests	--	--	(8.1)	(8.1)
Cash contributions from noncontrolling interests	--	--	5.9	5.9
Net cash proceeds from the issuance of common units	61.5	--	--	61.5
Amortization of fair value of equity-based awards	31.8	--	--	31.8
Cash flow hedges	--	32.9	--	32.9
Other	(22.1)	(0.2)	1.0	(21.3)
Balance, June 30, 2012	\$ 12,685.0	\$ (318.7)	\$ 109.8	\$ 12,476.1

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

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

**KEY REFERENCES USED 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 Products Partners L.P. conducts 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 Texas limited liability company.

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 and Chairman of the Board of Enterprise GP; (ii) Dr. Ralph S. Cunningham, who is also a director of Enterprise GP; and (iii) Richard H. Bachmann, who is also a director of Enterprise GP. Each of the DD LLC Trustees also currently serves as one of the three managers of Dan Duncan LLC.

References to “EPCO” mean Enterprise Products Company, a Texas corporation, 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 also serves as Chairman of EPCO; (ii) Dr. Cunningham, who also serves as a Vice Chairman of EPCO; and (iii) Mr. Bachmann, who also serves as the President and Chief Executive Officer (“CEO”) of EPCO. Each of the EPCO Trustees is also a director of EPCO.

References to “TEPPCO” mean TEPPCO Partners, L.P. prior to its merger with one of our wholly owned subsidiaries in October 2009 (the “TEPPCO Merger”).

Note 1. Partnership Operations, Organization and Basis of Presentation

General

We are a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange (“NYSE”) under the ticker symbol “EPD.” 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 petrochemicals.

Our integrated midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States (“U.S.”), Canada and Gulf of Mexico with domestic consumers and international markets. Our midstream energy operations include: natural gas gathering, treating, processing, transportation and storage; NGL transportation, fractionation, storage, and import and export terminals; crude oil gathering, transportation, storage and terminals; offshore production platforms; petrochemical and refined products transportation and services; and a marine transportation business that operates primarily on the U.S. inland and Intracoastal Waterway systems and in the Gulf of Mexico. Our assets include approximately 50,000 miles of onshore and offshore pipelines; 200 million barrels (“MMBbls”) of storage capacity for NGLs, petrochemicals, refined products and crude oil; and 14 billion cubic feet (“Bcf”) of natural gas storage capacity. In addition, our asset portfolio includes 24 natural gas processing plants, 21 NGL and propylene fractionators, six offshore hub platforms located in the Gulf of Mexico, a butane isomerization complex, NGL import and export terminals, and octane enhancement and high-purity isobutylene production facilities.

We have five reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services; and (v) Petrochemical & Refined Products Services. All activities included in our former sixth reportable business segment,

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

Other Investments, ceased on January 18, 2012, which was the date we discontinued using the equity method to account for our previously held investment in Energy Transfer Equity L.P. (together with its subsidiaries, “Energy Transfer Equity”) (see “Liquidation of Investment in Energy Transfer Equity” under Note 7).

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 under the collective common control of the DD LLC Trustees and the EPCO Trustees. We have no employees. All of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to an administrative services agreement (the “ASA”) or by other service providers. See Note 12 for information regarding the ASA and other related party matters.

Note 2. General Accounting Matters

Our results of operations for the three and six months ended June 30, 2013 are not necessarily indicative of results expected for the full year of 2013. 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 U.S. Securities and Exchange Commission (“SEC”).

These Unaudited Condensed Consolidated Financial Statements and the Notes thereto should be read in conjunction with the Audited Consolidated Financial Statements and Notes thereto included in our annual report on Form 10-K for the year ended December 31, 2012 (the “2012 Form 10-K”) filed with the SEC on March 1, 2013.

Allowance for Doubtful Accounts

Our allowance for doubtful accounts is determined based on specific identification and estimates of future uncollectible accounts. The following table presents our allowance for doubtful accounts activity for the periods indicated:

	For the Six Months			
	Ended June 30,			
	2013		2012	
Balance at beginning of period	\$	13.2	\$	13.4
Charged to costs and expenses		0.4		--
Deductions		(1.4)		(0.4)
Balance at end of period	\$	12.2	\$	13.0

Contingencies

Certain conditions may exist as of the date our consolidated 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 such 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.

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

For contingencies where an unfavorable outcome is reasonably possible and the impact would be material, we disclose the nature of the contingency and, if 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 futures, swaps, options, forward contracts and other arrangements to manage price risks associated with inventories, firm commitments, interest rates, foreign currencies and certain anticipated future commodity transactions. To qualify for hedge accounting, the hedged item must expose us to risk and the related derivative instrument must reduce the exposure to that risk and meet specific hedge documentation requirements related to designation dates, expectations for hedge effectiveness and the probability that hedged future transactions will occur as forecasted. We formally designate derivative instruments as hedges and document and assess their effectiveness at inception of the hedge and on a monthly basis thereafter. Forecasted transactions are evaluated for the probability of occurrence and are periodically back-tested once the forecasted period has passed to determine whether similarly forecasted transactions are probable of occurring in the future.

For certain physical forward commodity derivative contracts, we apply the normal purchase/normal sale exception, whereby changes in the mark-to-market values of such contracts are not recognized in income. As a result, the revenues and expenses associated with such physical contract transactions are recognized during the period when volumes are physically delivered or received. Physical forward commodity contracts subject to this exception are evaluated for the probability of future delivery and are periodically back-tested once the forecasted period has passed to determine whether similar forward contracts are probable of physical delivery in the future.

See Note 4 for additional information regarding our derivative instruments.

Estimates

Preparing our consolidated financial statements in conformity with U.S. GAAP requires us to make estimates that affect amounts presented in the financial statements. Our most significant estimates relate to (i) the useful lives and depreciation/amortization methods used for fixed and identifiable intangible assets; (ii) measurement of fair value and projections used in impairment testing of fixed and intangible assets (including goodwill); (iii) contingencies; and (iv) revenue and expense accruals.

Actual results could differ materially from our estimates. On an ongoing basis, we review our estimates based on currently available information. Any changes in the facts and circumstances underlying our estimates may require us to update such estimates, which could have a material impact on our consolidated financial statements.

Provision for Income Taxes

Provision for income taxes for the second quarter of 2013 increased \$11.9 million when compared to the second quarter of 2012 primarily due to Texas Margin Tax accruals. In June 2013, the State of Texas enacted certain changes to the Texas Margin Tax which lowered the tax rate and expanded the scope of depreciation deductions. As a result of these changes, current income tax expense decreased \$7.2 million and our deferred income tax expense (related to book/tax depreciation timing differences) increased \$20.3 million, for a net \$13.1 million expense in the second quarter of 2013.

We recognized a net income tax expense of \$26.8 million for the first six months of 2013 compared to a net income tax benefit of \$25.9 million for the same period in 2012. The \$52.7 million period-to-period change is primarily due to (i) a \$46.5 million benefit recorded in the first quarter of 2012 related to the conversion of certain of our subsidiaries to limited liability companies and (ii) the \$13.1 million of expense recorded in June 2013 related to the Texas Margin Tax (as discussed above).

The \$46.5 million net income tax benefit recorded in 2012 is attributable to the difference between deferred income taxes accrued by the applicable subsidiaries through the date of conversion and any current income tax due

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

in connection with the conversions. After taking into account certain tax loss carryforward amounts, we paid \$22.0 million in federal income taxes in connection with the conversions.

Other Non-Operating Income (Expense)

The following table presents the components of “Other, net” as presented on our Unaudited Condensed Statements of Consolidated Operations for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
Gain on sales of available-for-sale securities of Energy Transfer Equity (1)	\$ --	\$ 15.5	\$ --	\$ 68.8
Distribution income from Energy Transfer Equity	--	--	--	4.1
Other	(0.6)	(2.4)	(0.9)	(1.4)
Total	<u>\$ (0.6)</u>	<u>\$ 13.1</u>	<u>\$ (0.9)</u>	<u>\$ 71.5</u>

(1) See Note 7 for information regarding the liquidation of our investment in limited partnership units of Energy Transfer Equity.

Restricted Cash

Restricted cash represents amounts held in bank accounts as margin in support of our commodity derivative instruments portfolio and related physical natural gas, crude oil, refined products and NGL purchases. Additional cash may be restricted to maintain this portfolio as commodity prices fluctuate or deposit requirements change. At June 30, 2013 and December 31, 2012, our restricted cash amounts were \$26.3 million and \$4.3 million, respectively. See Note 4 for information regarding our derivative instruments and hedging activities.

Note 3. Equity-based Awards

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
Restricted common unit awards	\$ 18.3	\$ 15.7	\$ 34.9	\$ 30.5
Unit option awards	0.2	0.3	0.6	1.0
Other (1)	0.1	0.5	0.3	1.4
Total	<u>\$ 18.6</u>	<u>\$ 16.5</u>	<u>\$ 35.8</u>	<u>\$ 32.9</u>

(1) Primarily represents expense associated with unit appreciation rights (“UARs”), phantom units and similar awards.

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

At June 30, 2013, EPCO’s significant long-term incentive plans applicable to us were the Enterprise Products 1998 Long-Term Incentive Plan (“1998 Plan”) and the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan (“2008 Plan”). After giving effect to awards granted under the 1998 Plan and 2008 Plan through June 30, 2013, a total of 1,155,077 and 4,307,512 additional common units could be issued under these plans, respectively.

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

Restricted Common Unit Awards

Restricted common unit awards allow recipients to acquire our common units (at no cost to the recipient apart from service or other conditions) once a defined vesting period expires, subject to customary forfeiture provisions. As used in the context of EPCO's long-term incentive plans, the term "restricted common unit" represents a time-vested unit. Restricted common unit awards generally vest at a rate of 25% per year beginning one year after the grant date. 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.

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

	Number of Units	Weighted- Average Grant Date Fair Value per Unit (1)
Restricted common units at December 31, 2012	3,893,486	\$ 40.87
Granted (2,3)	1,748,476	\$ 57.15
Vested (3)	(1,830,010)	\$ 34.71
Forfeited	(120,882)	\$ 45.98
Restricted common units at June 30, 2013	3,691,070	\$ 51.46

- (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 during 2013 was \$99.9 million based on a grant date market price of our common units ranging from \$57.11 to \$59.74 per unit. An estimated annual forfeiture rate of 3.9% was applied to these awards.
- (3) Includes awards granted to the independent directors of the board of directors of Enterprise GP as part of their annual compensation for 2013. A total of 9,296 restricted common unit awards were issued to the independent directors of Enterprise GP, which immediately 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 to limited partners. Since these restricted common units are participating securities, such distributions are included in "Cash distributions paid to limited partners" as presented on our Unaudited Condensed Statements of Consolidated Cash Flows.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
Cash distributions paid to restricted common unitholders	\$ 3.0	\$ 3.0	\$ 5.6	\$ 5.4
Total intrinsic value of restricted common unit awards that vested during period	54.0	30.1	106.4	62.7

For the EPCO group of companies, the unrecognized compensation cost associated with restricted common unit awards was an aggregate \$109.4 million at June 30, 2013, of which our allocated share of the cost is currently estimated to be \$100.3 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.1 years.

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

Unit Option Awards

EPCO's long-term incentive plans provide for the issuance of non-qualified incentive options. These unit option awards are denominated in our common units. When issued, the exercise price of each unit option award may be no less than the market price of our common units on the date of grant. In general, unit option awards have a vesting period of four years from the date of grant and expire at the end of the calendar year following the year of vesting (e.g., an option vesting on May 29, 2012 will expire on December 31, 2013). However, unit option awards only become exercisable at certain times during the calendar year following the year in which they vest (typically the months of February, May, August and November).

The fair value of each unit option award is estimated on the date of grant using a Black-Scholes option pricing model. Compensation expense recorded in connection with unit option awards is based on the grant date fair value, net of an allowance for estimated forfeitures, over the requisite service or vesting period. The following table presents unit option award activity for the period indicated:

	Number of Units	Weighted- Average Strike Price (dollars/unit)	Weighted- Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (1)
Unit option awards at December 31, 2012	2,761,140	\$ 27.41	2.0	\$ 13.0
Exercised	(736,140)	\$ 29.95		
Unit option awards at June 30, 2013	<u>2,025,000</u>	\$ 26.49	<u>1.8</u>	\$ 51.4
Options exercisable at June 30, 2013	<u> --</u>	\$ --	<u> --</u>	\$ --

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

In order to fund its unit option award-related obligations, EPCO may purchase common units at fair value either in the open market or directly from us. When employees exercise unit option awards, 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 unit option awards during the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
Total intrinsic value of unit option awards exercised during period	\$ 3.4	\$ --	\$ 19.8	\$ 14.0
Cash received from EPCO in connection with the exercise of unit option awards	2.0	--	11.5	10.2
Unit option award-related cash reimbursements to EPCO	3.4	--	19.8	14.0

For the EPCO group of companies, the unrecognized compensation cost associated with unit option awards was an aggregate \$0.3 million at June 30, 2013, of which our allocated share of the cost is currently estimated to be \$0.3 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 0.6 years.

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

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 assets, liabilities and certain anticipated future transactions, we use derivative instruments such as 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 Unaudited Condensed Consolidated Balance Sheets unless such instruments meet certain normal purchase/normal sale criteria. While all derivatives are required to be reported at fair value on the balance sheet, changes in fair value of 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 not probable of 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 Hedging Activities

We may utilize interest rate swaps, forward starting swaps 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. Interest rate swaps exchange the stated interest rate paid on a notional amount of existing debt for the fixed or floating interest rate stipulated in the derivative instrument. Forward starting swaps perform a similar function except that they are associated with interest rates underlying anticipated future issuances of debt.

The following table summarizes our portfolio of interest rate swaps at June 30, 2013:

Hedged Transaction	Number and Type of Derivatives Outstanding	Notional Amount	Period of Hedge	Rate Swap	Accounting Treatment
Senior Notes AA	10 fixed-to-floating swaps	\$750.0	1/2011 to 2/2016	3.2% to 1.3%	Fair value hedge
Undesignated swaps	6 floating-to-fixed swaps	\$600.0	5/2010 to 7/2014	0.3% to 2.0%	Mark-to-market

In February 2012, we settled 11 fixed-to-floating interest rate swaps having an aggregate notional amount of \$800.0 million, resulting in gains totaling \$37.7 million. These gains are being amortized to earnings (as a decrease in interest expense) using the effective interest method over the forecasted hedged period of three years.

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

At December 31, 2012, our portfolio of forward starting interest rate swaps consisted of 16 derivative instruments having an aggregate notional amount of \$1.0 billion. Forward starting swaps hedge the expected underlying benchmark interest rates related to future issuances of debt. We accounted for these derivative instruments as cash flow hedges. In connection with the issuance of Senior Notes II and HH in March 2013 (see Note 9), we settled all 16 forward starting swaps that were outstanding at December 31, 2012, which resulted in cash payments totaling \$168.8 million. These losses are a component of accumulated other comprehensive income and are being amortized to earnings (as an increase in interest expense) over the forecasted hedge period of ten years using the effective interest method.

In connection with the issuance of Senior Notes EE in February 2012, we settled ten forward starting swaps having an aggregate notional amount of \$500.0 million, resulting in cash payments totaling \$115.3 million. These losses are a component of accumulated other comprehensive income and are being amortized to earnings (as an increase in interest expense) over the forecasted hedge period of ten years using the effective interest method.

Commodity Hedging Activities

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 contracts, futures contracts, fixed-for-float swaps, basis swaps and option contracts. The following table summarizes our portfolio of commodity derivative instruments outstanding at June 30, 2013 (volume measures as noted):

Derivative Purpose	Volume (1)		Accounting Treatment
	Current (2)	Long-Term (2)	
<u>Derivatives designated as hedging instruments:</u>			
Octane enhancement:			
Forecasted purchases of NGLs (MMBbls)	1.1	n/a	Cash flow hedge
Forecasted sales of octane enhancement products (MMBbls)	2.2	0.1	Cash flow hedge
Natural gas marketing:			
Forecasted sales of natural gas (Bcf)	2.3	n/a	Cash flow hedge
Natural gas storage inventory management activities (Bcf)	10.0	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	3.3	n/a	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	7.1	n/a	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products (MMBbls)	0.1	n/a	Cash flow hedge
Forecasted sales of refined products (MMBbls)	0.1	n/a	Cash flow hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	2.6	n/a	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	3.0	n/a	Cash flow hedge
<u>Derivatives not designated as hedging instruments:</u>			
Natural gas risk management activities (Bcf) (3,4)	145.7	24.0	Mark-to-market
Refined products risk management activities (MMBbls) (4)	0.5	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (4)	8.5	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 January 2015, February 2014 and March 2016, respectively.
- (3) Current and long-term volumes include 63.9 Bcf and 1.2 Bcf, respectively, of physical derivative instruments that are predominantly priced at a marked-based index plus a premium or minus a discount related to location differences.
- (4) Reflects the use of derivative instruments to manage risks associated with transportation, processing and storage assets.

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

At June 30, 2013, our predominant commodity hedging strategies consisted of (i) hedging anticipated future contracted sales of NGLs, crude oil, and related products associated with volumes held in inventory and (ii) hedging the fair value of natural gas and refined products in inventory. The following information summarizes these hedging strategies:

- The objective of our NGL, crude oil, and related products 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 and refined products inventory hedging program is to hedge the fair value of natural gas and refined products currently held in inventory by locking in the sales price of the inventory through the use of commodity derivative instruments.

At June 30, 2013, we did not have any hedges in place with respect to gross margins associated with our future natural gas processing activities. Management continues to evaluate market conditions to determine the appropriate timing to implement this strategy, if at all, during 2013.

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 and crude oil. 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 during the periods originally forecasted. In accordance with derivatives guidance, these instruments do not qualify for hedge accounting even though they are effective at managing the risk exposures of the underlying assets. The earnings volatility caused by fluctuations in non-cash, mark-to-market earnings cannot be predicted.

***Tabular Presentation of Fair Value Amounts, 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, 2013		December 31, 2012		June 30, 2013		December 31, 2012	
	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	\$ 19.8	Other current assets	\$ 19.6	Other current liabilities	\$ --	Other current liabilities	\$ 175.4
Interest rate derivatives	Other assets	15.7	Other assets	25.6	Other liabilities	--	Other liabilities	--
Total interest rate derivatives		<u>35.5</u>		<u>45.2</u>		<u>--</u>		<u>175.4</u>
Commodity derivatives	Other current assets	42.6	Other current assets	45.3	Other current liabilities	41.6	Other current liabilities	35.4
Commodity derivatives	Other assets	--	Other assets	--	Other liabilities	--	Other liabilities	0.5
Total commodity derivatives		<u>42.6</u>		<u>45.3</u>		<u>41.6</u>		<u>35.9</u>
Total derivatives designated as hedging instruments		<u>\$ 78.1</u>		<u>\$ 90.5</u>		<u>\$ 41.6</u>		<u>\$ 211.3</u>
Derivatives not designated as hedging instruments								
Interest rate derivatives	Other current assets	\$ --	Other current assets	\$ --	Other current liabilities	\$ 12.1	Other current liabilities	\$ 12.2
Interest rate derivatives	Other assets	--	Other assets	--	Other liabilities	0.3	Other liabilities	5.0
Total interest rate derivatives		<u>--</u>		<u>--</u>		<u>12.4</u>		<u>17.2</u>
Commodity derivatives	Other current assets	18.0	Other current assets	15.7	Other current liabilities	3.9	Other current liabilities	8.9
Commodity derivatives	Other assets	0.2	Other assets	0.6	Other liabilities	1.4	Other liabilities	0.7
Total commodity derivatives		<u>18.2</u>		<u>16.3</u>		<u>5.3</u>		<u>9.6</u>
Total derivatives not designated as hedging instruments		<u>\$ 18.2</u>		<u>\$ 16.3</u>		<u>\$ 17.7</u>		<u>\$ 26.8</u>

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

Certain of our commodity derivative instruments are subject to master netting arrangements or similar agreements. The following tables present our derivative instruments subject to such arrangements at the dates indicated:

Offsetting of Financial Assets and Derivative Assets									
	Gross Amounts of Recognized Assets (i)	Gross Amounts Offset in the Balance Sheet (ii)	Amounts of Assets Presented in the Balance Sheet (iii) = (i) – (ii)	Gross Amounts Not Offset in the Balance Sheet			Amounts That Would Have Been Presented On Net Basis (v) = (iii) – (iv)		
				Financial Instruments	Cash Collateral Received (iv)	Cash Collateral Paid			
As of June 30, 2013:									
Commodity derivatives	\$ 60.8	\$ --	\$ 60.8	\$ (43.2)	\$ --	\$ (14.3)	\$ 3.3		
As of December 31, 2012:									
Commodity derivatives	\$ 61.6	\$ --	\$ 61.6	\$ (38.7)	\$ (15.2)	\$ --	\$ 7.7		

Offsetting of Financial Liabilities and Derivative Liabilities									
	Gross Amounts of Recognized Liabilities (i)	Gross Amounts Offset in the Balance Sheet (ii)	Amounts of Liabilities Presented in the Balance Sheet (iii) = (i) – (ii)	Gross Amounts Not Offset in the Balance Sheet		Amounts That Would Have Been Presented On Net Basis (v) = (iii) – (iv)			
				Financial Instruments	Cash Collateral Paid (iv)				
As of June 30, 2013:									
Commodity derivatives	\$ 46.9	\$ --	\$ 46.9	\$ (43.2)	\$ --	\$ 3.7			
As of December 31, 2012:									
Commodity derivatives	\$ 45.5	\$ --	\$ 45.5	\$ (38.7)	\$ (4.3)	\$ 2.5			

Derivative assets and liabilities recorded in our Unaudited Condensed Consolidated Balance Sheets are presented on a gross-basis and determined at the individual transaction level. This presentation method is applied regardless of whether the respective exchange clearing agreements, counterparty contracts or master netting agreements contain netting language often referred to as “rights of offset.” Although derivative amounts are presented on a gross-basis, having rights of offset enable the settlement of a net as opposed to gross receivable or payable amount under a counterparty default or liquidation scenario.

Cash is paid and received as collateral under certain agreements, particularly for those associated with exchange transactions. For any cash collateral payments or receipts, corresponding assets or liabilities are recorded to reflect the variation margin deposits or receipts with exchange clearing brokers and customers. These balances are also presented on a gross-basis in our Unaudited Condensed Consolidated Balance Sheets.

The tabular presentation above provides a means for comparing the gross amount of derivative assets and liabilities, excluding associated accounts payable and receivable, to the net amount that would likely be receivable or payable under a default scenario based on the existence of rights of offset in the respective derivative agreements. Any cash collateral paid or received is reflected in this table, but only to the extent that it represents variation margins. Any amounts associated with derivative prepayments or initial margins that are not influenced by the derivative asset or liability amounts or those that are determined solely on their volumetric notional amounts are excluded from this table.

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

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

<u>Derivatives in Fair Value Hedging Relationships</u>	<u>Location</u>	<u>Gain (Loss) Recognized in Income on Derivative</u>			
		<u>For the Three Months Ended June 30,</u>		<u>For the Six Months Ended June 30,</u>	
		<u>2013</u>	<u>2012</u>	<u>2013</u>	<u>2012</u>
		Interest rate derivatives	Interest expense	\$ (6.6)	\$ 4.6
Commodity derivatives	Revenue	6.9	(16.4)	6.2	(15.7)
Total		<u>\$ 0.3</u>	<u>\$ (11.8)</u>	<u>\$ (3.9)</u>	<u>\$ (12.6)</u>

<u>Derivatives in Fair Value Hedging Relationships</u>	<u>Location</u>	<u>Gain (Loss) Recognized in Income on Hedged Item</u>			
		<u>For the Three Months Ended June 30,</u>		<u>For the Six Months Ended June 30,</u>	
		<u>2013</u>	<u>2012</u>	<u>2013</u>	<u>2012</u>
		Interest rate derivatives	Interest expense	\$ 6.5	\$ (4.5)
Commodity derivatives	Revenue	(4.9)	15.9	(11.6)	16.3
Total		<u>\$ 1.6</u>	<u>\$ 11.4</u>	<u>\$ (1.7)</u>	<u>\$ 12.9</u>

With respect to our derivative instruments designated as fair value hedges, amounts attributable to ineffectiveness and those excluded from the assessment of hedge effectiveness were not material to our consolidated financial statements during the periods indicated.

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

<u>Derivatives in Cash Flow Hedging Relationships</u>	<u>Change in Value Recognized in Other Comprehensive Income (Loss) on Derivative (Effective Portion)</u>			
	<u>For the Three Months Ended June 30,</u>		<u>For the Six Months Ended June 30,</u>	
	<u>2013</u>	<u>2012</u>	<u>2013</u>	<u>2012</u>
	Interest rate derivatives	\$ --	\$ (84.0)	\$ 6.7
Commodity derivatives – Revenue	34.1	99.8	(13.5)	60.2
Commodity derivatives – Operating costs and expenses	--	5.2	--	(14.8)
Total	<u>\$ 34.1</u>	<u>\$ 21.0</u>	<u>\$ (6.8)</u>	<u>\$ (9.7)</u>

<u>Derivatives in Cash Flow Hedging Relationships</u>	<u>Location</u>	<u>Gain (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) to Income (Effective Portion)</u>			
		<u>For the Three Months Ended June 30,</u>		<u>For the Six Months Ended June 30,</u>	
		<u>2013</u>	<u>2012</u>	<u>2013</u>	<u>2012</u>
		Interest rate derivatives	Interest expense	\$ (7.8)	\$ (3.7)
Commodity derivatives	Revenue	7.2	(2.6)	(0.5)	(12.6)
Commodity derivatives	Operating costs and expenses	--	(11.6)	0.4	(23.6)
Total		<u>\$ (0.6)</u>	<u>\$ (17.9)</u>	<u>\$ (13.8)</u>	<u>\$ (42.6)</u>

<u>Derivatives in Cash Flow Hedging Relationships</u>	<u>Location</u>	<u>Gain (Loss) Recognized in Income on Derivative (Ineffective Portion)</u>			
		<u>For the Three Months Ended June 30,</u>		<u>For the Six Months Ended June 30,</u>	
		<u>2013</u>	<u>2012</u>	<u>2013</u>	<u>2012</u>
		Commodity derivatives	Revenue	\$ (0.1)	\$ 0.9
Commodity derivatives	Operating costs and expenses	--	--	--	0.3
Total		<u>\$ (0.1)</u>	<u>\$ 0.9</u>	<u>\$ (0.1)</u>	<u>\$ 1.2</u>

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

Over the next twelve months, we expect to reclassify \$31.3 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 \$3.2 million of losses attributable to commodity derivative instruments from accumulated other comprehensive loss to earnings 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 indicated:

<u>Derivatives Not Designated as Hedging Instruments</u>	<u>Location</u>	<u>Gain (Loss) Recognized in Income on Derivative</u>			
		<u>For the Three Months Ended June 30,</u>		<u>For the Six Months Ended June 30,</u>	
		<u>2013</u>	<u>2012</u>	<u>2013</u>	<u>2012</u>
		Interest rate derivatives	Interest expense	\$ (0.2)	\$ (1.1)
Commodity derivatives	Revenue	14.2	9.3	8.9	30.1
Commodity derivatives	Operating costs and expenses	--	--	--	(2.8)
Total		<u>\$ 14.0</u>	<u>\$ 8.2</u>	<u>\$ 8.8</u>	<u>\$ 24.0</u>

Fair Value Measurements

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, in the principal market of the asset or liability at a specified measurement date. Recognized valuation techniques employ inputs such as contractual prices, quoted market prices or rates, 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 highest 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 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.

Recurring Fair Value Measurements

The following table sets forth, by level within the fair value hierarchy, the carrying values of our financial assets and liabilities at June 30, 2013. These assets and liabilities are measured on a recurring basis and are classified based on the lowest level of input used to estimate their fair value. Our assessment of the relative significance of such inputs requires judgment.

	<u>Fair Value Measurements Using</u>			
	<u>Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)</u>	<u>Significant Other Observable Inputs (Level 2)</u>	<u>Significant Unobservable Inputs (Level 3)</u>	<u>Carrying Value at June 30, 2013</u>
Financial assets:				
Interest rate derivatives	\$ --	\$ 35.5	\$ --	\$ 35.5
Commodity derivatives	20.5	40.2	0.1	60.8
Total	<u>\$ 20.5</u>	<u>\$ 75.7</u>	<u>\$ 0.1</u>	<u>\$ 96.3</u>
Financial liabilities:				
Interest rate derivatives	\$ --	\$ 12.4	\$ --	\$ 12.4
Commodity derivatives	8.9	37.7	0.3	46.9
Total	<u>\$ 8.9</u>	<u>\$ 50.1</u>	<u>\$ 0.3</u>	<u>\$ 59.3</u>

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

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

	<u>Location</u>	<u>For the Six Months Ended June 30,</u>	
		<u>2013</u>	<u>2012</u>
Financial asset (liability) balance, net, January 1		\$ (1.5)	\$ 0.4
Total gains (losses) included in:			
Net income (1)	Revenue	(0.6)	0.5
Other comprehensive income	Commodity derivative instruments – changes in fair value of cash flow hedges	--	0.5
Settlements	Revenue	1.5	(0.5)
Financial asset (liability) balance, net, March 31		(0.6)	0.9
Total gains (losses) included in:			
Net income (1)	Revenue	(0.2)	(1.3)
Other comprehensive income	Commodity derivative instruments – changes in fair value of cash flow hedges	--	6.0
Settlements	Revenue	0.6	(0.7)
Financial asset (liability) balance, net, June 30 (2)		<u>\$ (0.2)</u>	<u>\$ 4.9</u>

(1) There were unrealized gains of \$0.4 million and \$1.3 million included in these amounts for the three and six months ended June 30, 2013, respectively. There were \$2.0 million and \$1.9 million of unrealized losses included in these amounts for the three and six months ended June 30, 2012, respectively.

(2) There were no transfers into or out of Level 3 during the three or six months ended June 30, 2013.

The following table provides quantitative information about our recurring Level 3 fair value measurements at June 30, 2013:

	<u>Fair Value</u>		<u>Valuation Techniques</u>	<u>Unobservable Input</u>	<u>Range</u>
	<u>Financial Assets</u>	<u>Financial Liabilities</u>			
Commodity derivatives – Crude oil	\$ 0.1	\$ 0.3	Discounted cash flow	Forward commodity prices	\$94.20-\$96.63/barrel

We believe forward commodity prices are the most significant unobservable inputs in determining our Level 3 recurring fair value measurements at June 30, 2013. In general, changes in the price of the underlying commodity increases or decreases the fair value of a commodity derivative depending on whether the derivative was purchased or sold. We generally expect changes in the fair value of our derivative instruments to be offset by corresponding changes in the fair value of our hedged exposures.

We have a risk management policy that covers our Level 3 commodity derivatives. Governance and oversight of risk management activities for these commodities are provided by our CEO with guidance and support from a risk management committee (“RMC”) that meets quarterly (or on a more frequent basis, if needed). Members of executive management attend the RMC meetings, which are chaired by the head of our commodities risk control group. This group is responsible for preparing and distributing daily reports and risk analysis to members of the RMC and other appropriate members of management. These reports include mark-to-market valuations with the one-day and month-to-date changes in fair values. This group also develops and validates the forward commodity price curves used to estimate the fair values of our Level 3 commodity derivatives. These forward curves incorporate published indexes, market quotes and other observable inputs to the extent available.

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

Nonrecurring Fair Value Measurements

The following table summarizes our non-cash asset impairment charges by segment during each of the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
NGL Pipelines & Services	\$ 8.7	\$ 2.9	\$ 9.7	\$ 8.0
Onshore Crude Oil Pipelines & Services	16.6	6.2	16.6	6.2
Petrochemical & Refined Products Services	1.8	--	11.8	0.3
Total	<u>\$ 27.1</u>	<u>\$ 9.1</u>	<u>\$ 38.1</u>	<u>\$ 14.5</u>

These impairment charges are a component of operating costs and expenses on our Unaudited Condensed Statements of Consolidated Operations.

During the six months ended June 30, 2013, we recorded \$38.1 million of non-cash asset impairment charges primarily due to the abandonment of assets classified as property, plant and equipment. Of this amount, \$16.6 million relates to the abandonment of certain crude oil pipeline segments in Texas and Oklahoma, \$10.0 million relates to the abandonment of certain refined products terminal and storage assets located in southeast Texas, and \$6.3 million relates to the abandonment of an NGL storage cavern in Arizona. The following table summarizes our non-recurring fair value measurements for the six months ended June 30, 2013:

	Fair Value Measurements Using				Total Non-Cash Impairment Loss
	Carrying Value at June 30, 2013	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	
Impairment of long-lived assets disposed of other than by sale	\$ --	\$ --	\$ --	\$ --	\$ 29.8
Impairment of long-lived assets held and used	6.3	--	--	6.3	4.2
Impairment of long-lived assets to be disposed of by sale	34.6	33.8	--	0.8	4.1
Total	<u>\$ 40.9</u>				<u>\$ 38.1</u>

During the six months ended June 30, 2012, we recorded \$14.5 million of non-cash asset impairment charges primarily due to the abandonment of assets classified as property, plant and equipment. Of this amount, \$6.2 million relates to the abandonment of certain crude oil pipeline segments in Texas and Oklahoma, \$4.6 million relates to the abandonment of an NGL fractionator in South Texas, and \$2.9 million relates to abandonment of certain segments of the Tri-States pipeline. The following table summarizes our non-recurring fair value measurements for the six months ended June 30, 2012:

	Fair Value Measurements Using				Total Non-Cash Impairment Loss
	Carrying Value at June 30, 2012	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	
Impairment of long-lived assets disposed of other than by sale	\$ --	\$ --	\$ --	\$ --	\$ 14.2
Impairment of long-lived assets to be disposed of by sale	--	--	--	--	0.3
Total	<u>\$ --</u>				<u>\$ 14.5</u>

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

Other Fair Value Information

The carrying amounts of cash and cash equivalents (including restricted cash balances), accounts receivable, commercial paper notes and accounts payable approximate their fair values based on their short-term nature. The estimated total fair value of our long-term fixed-rate debt obligations was \$17.98 billion and \$18.42 billion at June 30, 2013 and December 31, 2012, respectively. The aggregate carrying value of these debt obligations was \$16.88 billion and \$16.18 billion at June 30, 2013 and December 31, 2012, respectively. These values are based on quoted market prices for such debt or debt of similar terms and maturities (Level 2), our credit standing and the credit standing of our counterparties. Changes in market rates of interest affect the fair value of our fixed-rate debt. The carrying values of our variable-rate long-term debt obligations approximate their fair values since the associated interest rates are market-based. We do not have any long-term investments in debt or equity securities recorded at fair value.

Note 5. Inventories

Our available-for-sale inventory amounts by product type were as follows at the dates indicated:

	June 30, 2013	December 31, 2012
NGLs	\$ 799.1	\$ 594.3
Petrochemicals and refined products	394.0	304.5
Crude oil	156.9	119.4
Natural gas	61.4	70.2
Total	<u>\$ 1,411.4</u>	<u>\$ 1,088.4</u>

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

Due to fluctuating commodity prices, we recognize lower of cost or market adjustments when the carrying value of our available-for-sale 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 presents our total cost of sales amounts and lower of cost or market adjustments for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
Cost of sales (1)	\$ 9,458.3	\$ 8,195.2	\$ 19,150.8	\$ 17,861.0
Lower of cost or market adjustments	7.7	8.0	10.4	13.9

(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.

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

Note 6. Property, Plant and Equipment

The historical costs of our property, plant and equipment and related accumulated depreciation balances were as follows at the dates indicated:

	Estimated Useful Life in Years	June 30, 2013	December 31, 2012
Plants, pipelines and facilities (1)	3-45 (6)	\$ 26,455.2	\$ 25,382.4
Underground and other storage facilities (2)	5-40 (7)	1,895.8	1,826.3
Platforms and facilities (3)	20-31	664.8	635.2
Transportation equipment (4)	3-10	132.1	136.2
Marine vessels (5)	15-30	713.3	695.0
Land		179.0	167.2
Construction in progress		2,104.7	2,113.1
Total		32,144.9	30,955.4
Less accumulated depreciation		6,578.8	6,109.0
Property, plant and equipment, net		\$ 25,566.1	\$ 24,846.4

- (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.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
Depreciation expense (1)	\$ 250.8	\$ 222.0	\$ 496.2	\$ 434.0
Capitalized interest (2)	35.7	29.5	67.3	60.1

- (1) Depreciation expense is a component of "Costs and expenses" as presented on our Unaudited Condensed Statements of Consolidated Operations.
- (2) We capitalize interest cost incurred on funds used to construct property, plant and equipment. The capitalized interest is recorded as part of the asset to which it relates and is amortized over the asset's estimated useful life as a component of depreciation expense. When capitalized interest is recorded, it reduces interest expense from what it would be otherwise.

In January 2013, we sold certain trucking assets for cash proceeds of \$29.5 million. As a result of this transaction, net income for the six months ended June 30, 2013 includes a \$0.5 million loss from the sale of these assets.

In March 2013, we sold the Stratton Ridge-to-Mont Belvieu segment of the Seminole Pipeline, along with a related storage cavern, for cash proceeds of \$86.9 million. As a result, net income for the six months ended June 30, 2013 includes a \$52.5 million gain from the sale of these assets. The Seminole Pipeline remains connected to our Mont Belvieu complex through a newly constructed NGL pipeline that we own.

In April 2013, we sold certain lubrication oil and specialty chemical distribution assets for cash proceeds of \$35.3 million. As a result, net income for the three and six months ended June 30, 2013 includes a \$6.7 million gain from the sale of these assets.

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

We received cash proceeds of \$14.3 million and \$14.9 million from the sale of certain marine transportation assets during the three and six months ended June 30, 2013, respectively. As a result of these transactions, net income for the three and six months ended June 30, 2013 includes a \$6.7 million loss from the sale of these assets.

Asset Retirement Obligations

Property, plant and equipment at June 30, 2013 and December 31, 2012 includes \$40.9 million and \$40.3 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset.

The following table presents information regarding our asset retirement obligations (“AROs”) during the six months ended June 30, 2013:

ARO liability balance, December 31, 2012	\$	105.2
Liabilities incurred		0.1
Liabilities settled		(6.8)
Revisions in estimated cash flows		2.9
Accretion expense		3.1
ARO liability balance, June 30, 2013	<u>\$</u>	<u>104.5</u>

The following table presents our forecast of accretion expense for the periods indicated:

Remainder of 2013	2014	2015	2016	2017
\$ 3.1	\$ 6.5	\$ 6.3	\$ 6.6	\$ 7.1

Certain of our unconsolidated affiliates have AROs recorded at June 30, 2013 and December 31, 2012 relating to contractual agreements and regulatory requirements. These amounts are immaterial to our consolidated financial statements.

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

Note 7. Investments in Unconsolidated Affiliates

The following table presents our investments in unconsolidated affiliates by business segment at the dates indicated. Unless noted otherwise, we account for these investments using the equity method.

	Ownership Interest at June 30, 2013	June 30, 2013	December 31, 2012
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C.	13.1%	\$ 30.6	\$ 29.6
K/D/S Promix, L.L.C.	50%	45.2	46.9
Baton Rouge Fractionators LLC	32.2%	19.4	20.2
Skelly-Belvieu Pipeline Company, L.L.C.	50%	40.3	38.2
Texas Express Pipeline LLC	35%	282.7	144.4
Texas Express Gathering LLC	45%	29.2	20.9
Front Range Pipeline LLC	33.3%	68.1	24.4
Onshore Natural Gas Pipelines & Services:			
White River Hub, LLC	50%	24.4	24.9
Onshore Crude Oil Pipelines & Services:			
Seaway Crude Pipeline Company LLC	50%	558.1	341.4
Eagle Ford Pipeline LLC	50%	225.0	152.4
Offshore Pipelines & Services:			
Poseidon Oil Pipeline Company, L.L.C. ("Poseidon")	36%	45.4	47.3
Cameron Highway Oil Pipeline Company	50%	211.1	220.0
Deepwater Gateway, L.L.C.	50%	87.2	90.0
Neptune Pipeline Company, L.L.C.	25.7%	44.6	46.8
Southeast Keathley Canyon Pipeline Company L.L.C.	50%	155.0	74.9
Petrochemical & Refined Products Services:			
Baton Rouge Propylene Concentrator, LLC	30%	8.0	8.5
Centennial Pipeline LLC ("Centennial")	50%	61.5	60.8
Other (1)	Various	3.0	3.0
Total		\$ 1,938.8	\$ 1,394.6

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
NGL Pipelines & Services	\$ 3.8	\$ 3.8	\$ 7.7	\$ 9.0
Onshore Natural Gas Pipelines & Services	0.9	1.2	1.9	2.6
Onshore Crude Oil Pipelines & Services	30.1	3.6	66.7	4.1
Offshore Pipelines & Services	8.7	4.1	15.1	11.0
Petrochemical & Refined Products Services	(5.9)	(1.4)	(9.3)	(7.9)
Other Investments	--	--	--	2.4
Total	\$ 37.6	\$ 11.3	\$ 82.1	\$ 21.2

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

The following table presents our unamortized excess cost amounts by business segment at the dates indicated:

	June 30, 2013	December 31, 2012
NGL Pipelines & Services	\$ 28.3	\$ 28.9
Onshore Crude Oil Pipelines & Services	18.1	18.5
Offshore Pipelines & Services	12.9	13.6
Petrochemical & Refined Products Services	2.7	2.7
Total	\$ 62.0	\$ 63.7

The following table presents our amortization of excess cost amounts by business segment for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
NGL Pipelines & Services	\$ 0.3	\$ 0.3	\$ 0.6	\$ 0.5
Onshore Crude Oil Pipelines & Services	0.2	0.1	0.4	0.3
Offshore Pipelines & Services	0.4	0.3	0.7	0.6
Petrochemical & Refined Products Services	--	--	--	0.1
Other Investments	--	--	--	0.3
Total	\$ 0.9	\$ 0.7	\$ 1.7	\$ 1.8

Liquidation of Investment in Energy Transfer Equity

The Other Investments segment included our noncontrolling ownership interest in Energy Transfer Equity, which was accounted for using the equity method until January 18, 2012.

At December 31, 2011, we owned 29,303,514 common units of Energy Transfer Equity representing 13.1% of its limited partner interests. On January 18, 2012, we sold 22,762,636 of these common units in a private transaction, which generated cash proceeds of \$825.1 million and a gain on the sale of \$27.5 million. As a result of the January 18, 2012 transaction, our ownership interest in Energy Transfer Equity was reduced below 3%, and we discontinued using the equity method to account for this investment and began accounting for it as an investment in available-for-sale equity securities. Following the January 18, 2012 transaction, we sold the remaining 6,540,878 Energy Transfer Equity common units through April 27, 2012, which generated cash proceeds of \$270.2 million and gains on these sales totaling \$41.3 million. The \$68.8 million of aggregate gains on the 2012 sales, of which \$15.5 million are attributed to sales during the second quarter of 2012, are a component of "Other income" on our Unaudited Condensed Statements of Consolidated Operations.

All activities included in our former sixth reportable business segment, Other Investments, ceased on January 18, 2012, which was the date we discontinued using the equity method to account for our investment in Energy Transfer Equity. See Note 11 for additional information regarding our business segments.

Summarized Income Statement Information of Unconsolidated Affiliates

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

	Summarized Income Statement Information for the Three Months Ended					
	June 30, 2013			June 30, 2012		
	Revenues	Operating Income (Loss)	Net Income (Loss)	Revenues	Operating Income (Loss)	Net Income (Loss)
NGL Pipelines & Services	\$ 71.5	\$ 12.7	\$ 12.6	\$ 71.5	\$ 15.3	\$ 15.2
Onshore Natural Gas Pipelines & Services	2.9	1.8	1.8	2.9	1.9	1.9
Onshore Crude Oil Pipelines & Services	88.4	63.4	59.1	21.5	7.4	7.3
Offshore Pipelines & Services	46.9	24.2	23.9	39.1	12.8	12.5
Petrochemical & Refined Products Services	5.7	(9.2)	(11.0)	5.9	(0.3)	(2.4)

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

	Summarized Income Statement Information for the Six Months Ended					
	June 30, 2013			June 30, 2012		
	Revenues	Operating Income (Loss)	Net Income (Loss)	Revenues	Operating Income (Loss)	Net Income (Loss)
NGL Pipelines & Services	\$ 154.9	\$ 28.0	\$ 27.8	\$ 182.4	\$ 42.3	\$ 42.2
Onshore Natural Gas Pipelines & Services	5.8	3.7	3.7	5.7	3.7	3.7
Onshore Crude Oil Pipelines & Services	166.9	135.1	127.0	33.8	8.2	8.1
Offshore Pipelines & Services	89.2	42.2	41.2	80.2	31.9	30.9
Petrochemical & Refined Products Services	11.7	(13.1)	(16.8)	11.3	(9.7)	(13.8)

Other

The credit agreements of Poseidon and Centennial restrict their ability to pay cash dividends if a default or event of default (as defined in each credit agreement) has occurred and is continuing at the time such payments are scheduled to be paid. These businesses were in compliance with the terms of their credit agreements at June 30, 2013.

Note 8. Intangible Assets and Goodwill

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

	June 30, 2013			December 31, 2012		
	Gross Value	Accumulated Amortization	Carrying Value	Gross Value	Accumulated Amortization	Carrying Value
NGL Pipelines & Services:						
Customer relationship intangibles	\$ 340.8	\$ (156.8)	\$ 184.0	\$ 340.8	\$ (147.6)	\$ 193.2
Contract-based intangibles	280.3	(162.8)	117.5	284.6	(157.2)	127.4
Segment total	621.1	(319.6)	301.5	625.4	(304.8)	320.6
Onshore Natural Gas Pipelines & Services:						
Customer relationship intangibles	1,163.6	(265.3)	898.3	1,163.6	(250.0)	913.6
Contract-based intangibles	466.1	(321.2)	144.9	466.1	(311.8)	154.3
Segment total	1,629.7	(586.5)	1,043.2	1,629.7	(561.8)	1,067.9
Onshore Crude Oil Pipelines & Services:						
Customer relationship intangibles	10.7	(5.6)	5.1	10.7	(4.9)	5.8
Contract-based intangibles	0.4	(0.3)	0.1	0.4	(0.3)	0.1
Segment total	11.1	(5.9)	5.2	11.1	(5.2)	5.9
Offshore Pipelines & Services:						
Customer relationship intangibles	203.9	(144.5)	59.4	203.9	(138.5)	65.4
Contract-based intangibles	1.2	(0.4)	0.8	1.2	(0.4)	0.8
Segment total	205.1	(144.9)	60.2	205.1	(138.9)	66.2
Petrochemical & Refined Products Services:						
Customer relationship intangibles	104.3	(35.9)	68.4	104.3	(33.4)	70.9
Contract-based intangibles	39.9	(5.2)	34.7	41.2	(5.9)	35.3
Segment total	144.2	(41.1)	103.1	145.5	(39.3)	106.2
Total all segments	\$ 2,611.2	\$ (1,098.0)	\$ 1,513.2	\$ 2,616.8	\$ (1,050.0)	\$ 1,566.8

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

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
NGL Pipelines & Services	\$ 9.5	\$ 9.6	\$ 19.1	\$ 19.8
Onshore Natural Gas Pipelines & Services	12.3	15.8	24.7	31.6
Onshore Crude Oil Pipelines & Services	0.4	0.1	0.7	0.3
Offshore Pipelines & Services	2.9	2.6	5.9	5.2
Petrochemical & Refined Products Services	1.6	3.2	3.2	6.7
Total	<u>\$ 26.7</u>	<u>\$ 31.3</u>	<u>\$ 53.6</u>	<u>\$ 63.6</u>

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

Remainder of 2013	2014	2015	2016	2017
\$ 51.7	\$ 96.2	\$ 90.3	\$ 92.0	\$ 96.0

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. The following table presents changes in the carrying amount of goodwill during the six months ended June 30, 2013:

	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, 2012 (1)	\$ 341.2	\$ 296.3	\$ 311.2	\$ 82.1	\$ 1,056.0	\$ 2,086.8
Goodwill related to the sale of assets	--	--	(6.1)	--	(0.7)	(6.8)
Balance at June 30, 2013 (1)	<u>\$ 341.2</u>	<u>\$ 296.3</u>	<u>\$ 305.1</u>	<u>\$ 82.1</u>	<u>\$ 1,055.3</u>	<u>\$ 2,080.0</u>

(1) The total carrying amount of goodwill at June 30, 2013 and December 31, 2012 is net of \$1.3 million of accumulated impairment charges. No goodwill impairment charges were recorded during the six months ended June 30, 2013.

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

Note 9. Debt Obligations

The following table presents our consolidated debt obligations (arranged by company and maturity date) at the dates indicated:

	June 30, 2013	December 31, 2012
EPO senior debt obligations:		
Commercial Paper Notes, fixed-rates (1)	\$ 40.0	\$ 346.6
Senior Notes C, 6.375% fixed-rate, due February 2013	--	350.0
Senior Notes T, 6.125% fixed-rate, due February 2013	--	182.5
Senior Notes M, 5.65% fixed-rate, due April 2013	--	400.0
Senior Notes U, 5.90% fixed-rate, due April 2013	--	237.6
Senior Notes O, 9.75% fixed-rate, due January 2014	500.0	500.0
364-Day Credit Agreement, variable-rate, due June 2014	--	--
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 FF, 1.25% fixed-rate, due August 2015	650.0	650.0
Senior Notes AA, 3.20% fixed-rate, due February 2016	750.0	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
\$3.5 Billion Multi-Year Revolving Credit Facility, variable-rate, due June 2018	45.0	--
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 CC, 4.05% fixed-rate, due February 2022	650.0	650.0
Senior Notes HH, 3.35% fixed-rate, due March 2023	1,250.0	--
Senior Notes D, 6.875% fixed-rate, due March 2033	500.0	500.0
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	750.0
Senior Notes DD, 5.70% fixed-rate, due February 2042	600.0	600.0
Senior Notes EE, 4.85% fixed-rate, due August 2042	750.0	750.0
Senior Notes GG, 4.45% fixed-rate, due February 2043	1,100.0	1,100.0
Senior Notes II, 4.85% fixed-rate, due March 2044	1,000.0	--
TEPPCO senior debt obligations:		
TEPPCO Senior Notes, 6.125% fixed-rate, due February 2013	--	17.5
TEPPCO Senior Notes, 5.90% fixed-rate, due April 2013	--	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
Total principal amount of senior debt obligations	15,435.0	14,646.6
EPO Junior Subordinated Notes A, fixed/variable-rate, due August 2066	550.0	550.0
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	16,967.7	16,179.3
Other, non-principal amounts:		
Change in fair value of debt hedged in fair value hedging relationship (2)	29.3	39.3
Unamortized discounts, net of premiums	(42.2)	(38.0)
Other	14.8	21.2
Total other, non-principal amounts	1.9	22.5
Less current maturities of debt (3)	(540.0)	(1,546.6)
Total long-term debt	\$ 16,429.6	\$ 14,655.2

(1) Principal amounts outstanding at June 30, 2013 have a fixed-rate of 0.29% and are due in July 2013.

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

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

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

Enterprise Products Partners L.P. acts as guarantor of the consolidated debt obligations of EPO with the exception of 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 and unconditional repayment of that obligation.

The following table presents contractually scheduled maturities of our consolidated debt obligations outstanding at June 30, 2013 for the next five years, and in total thereafter:

	Scheduled Maturities of Debt						After 2017
	Total	Remainder of 2013	2014	2015	2016	2017	
Commercial Paper Notes	\$ 40.0	\$ 40.0	\$ --	\$ --	\$ --	\$ --	\$ --
Multi-Year Revolving Credit Facility	45.0	--	--	--	--	--	45.0
Senior Notes	15,350.0	--	1,150.0	1,300.0	750.0	800.0	11,350.0
Junior Subordinated Notes	1,532.7	--	--	--	--	--	1,532.7
Total	\$ 16,967.7	\$ 40.0	\$ 1,150.0	\$ 1,300.0	\$ 750.0	\$ 800.0	\$ 12,927.7

Apart from those items discussed below and routine fluctuations in the balance of our multi-year revolving credit facility and commercial paper notes, there have been no significant changes in the terms or amounts of our consolidated debt obligations since those reported in our 2012 Form 10-K.

364-Day Credit Agreement

In June 2013, EPO entered into a 364-Day Revolving Credit Agreement with a group of lenders (the “364-Day Credit Agreement”). Under the terms of the 364-Day Credit Agreement, EPO may borrow up to \$1.0 billion at a variable interest rate for a term of 364 days, subject to the terms and conditions set forth therein.

EPO’s obligations under the 364-Day Credit Agreement are not secured by any collateral; however, they are guaranteed by Enterprise Products Partners L.P. Amounts borrowed under the 364-Day Credit Agreement mature on June 18, 2014, although EPO may, between 15 and 60 days prior to the maturity date, elect to have the entire principal balance then outstanding continued as non-revolving term loans for a period of one additional year, payable on June 18, 2015.

The 364-Day Credit Agreement contains customary representations, warranties, covenants (affirmative and negative) and events of default, the occurrence of which would permit the lenders to accelerate the maturity date of amounts borrowed under the 364-Day Credit Agreement. The 364-Day Credit Agreement also restricts EPO’s ability to pay cash distributions to its parent, Enterprise Products Partners L.P., if a default or an event of default (as defined in the 364-Day Credit Agreement) has occurred and is continuing at the time such distribution is scheduled to be paid.

First Amendment to \$3.5 Billion Multi-Year Revolving Credit Facility

In June 2013, EPO amended the terms of its \$3.5 Billion Multi-Year Revolving Credit Facility to, among other things, extend the maturity date of commitments under the agreement from September 2016 to June 2018 and lower the applicable margin on borrowings.

Issuance of Senior Notes in March 2013

In March 2013, EPO issued \$1.25 billion principal amount of 3.35% senior notes due March 2023 (“Senior Notes HH”) and \$1.0 billion principal amount of 4.85% senior notes due March 2044 (“Senior Notes II”). Senior Notes HH were issued at 99.908% of their principal amount and Senior Notes II were issued at 99.619% of their principal amount. Net proceeds from the issuance of Senior Notes HH and II were used to repay debt, including (i) amounts outstanding under EPO’s \$3.5 Billion Multi-Year Revolving Credit Facility and EPO’s commercial paper program (which we used to repay \$550.0 million principal amount of senior notes that matured in February 2013) and (ii) \$650.0 million principal amount of senior notes that matured in April 2013, and for general company purposes.

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

Enterprise Products Partners L.P. has unconditionally guaranteed Senior Notes HH and II on an unsecured and unsubordinated basis. These senior notes rank equal with EPO's existing and future unsecured and unsubordinated indebtedness and are senior to any existing and future subordinated indebtedness of EPO. These senior notes 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.

Letters of Credit

At June 30, 2013, EPO had \$2.5 million of letters of credit outstanding related to operations at our facilities and motor fuel tax obligations.

Lender Financial Covenants

We were in compliance with the financial covenants of our consolidated debt agreements at June 30, 2013.

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 during the six months ended June 30, 2013:

	Range of Interest Rates Paid	Weighted-Average Interest Rate Paid
EPO \$3.5 Billion Multi-Year Revolving Credit Facility	1.17% to 1.51%	1.36%

Note 10. Equity and Distributions

Partners' equity reflects the various classes of limited partner interests (i.e., common units, including restricted common units, and Class B units) that we have outstanding. The following table summarizes changes in the number of our common units outstanding during the six months ended June 30, 2013:

	Common Units (Unrestricted)	Restricted Common Units	Total Common Units
Number of units outstanding at December 31, 2012	894,919,851	3,893,486	898,813,337
Common units issued in connection with underwritten offering	9,200,000	--	9,200,000
Common units issued in connection with our at-the-market program	3,766,557	--	3,766,557
Common units issued in connection with our DRIP and EUPP	2,440,784	--	2,440,784
Common units issued in connection with the vesting of unit options	200,882	--	200,882
Common units issued in connection with the vesting of restricted common unit awards	1,830,010	(1,830,010)	--
Restricted common unit awards issued	--	1,748,476	1,748,476
Forfeiture of restricted common unit awards	--	(120,882)	(120,882)
Acquisition and cancellation of treasury units in connection with the vesting of equity-based awards	(614,191)	--	(614,191)
Number of units outstanding at June 30, 2013	911,743,893	3,691,070	915,434,963

We may issue additional equity or debt securities to assist us in meeting our future liquidity and capital spending requirements. In June 2013, we filed with the SEC a new universal shelf registration statement (the "2013 Shelf") that replaced our prior universal shelf registration statement filed with the SEC in July 2010 (the "2010 Shelf"). The 2013 Shelf allows (and the prior 2010 Shelf allowed) Enterprise Products Partners L.P. and EPO (each on a standalone basis) to issue an unlimited amount of equity and debt securities, respectively.

In February 2013, we issued 9,200,000 common units to the public (including an over-allotment amount of 1,200,000 common units) at an offering price of \$54.56 per unit. This underwritten offering, using the 2010 Shelf, generated net proceeds of \$486.6 million. Also, EPO utilized the 2010 Shelf to issue \$2.25 billion of senior notes in March 2013 (see Note 9).

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

We have a registration statement on file with the SEC covering the issuance of up to \$1.0 billion of our common units in amounts, at prices and on terms to be determined by market conditions and other factors at the time of such offerings. Pursuant to this “at-the-market” program, we may sell common units under an equity distribution agreement between Enterprise Products Partners L.P. and certain broker-dealers from time-to-time by means of ordinary brokers’ transactions through the NYSE at market prices, in block transactions or as otherwise agreed to with the broker-dealer parties to the agreement. During the six months ended June 30, 2013, we sold 3,766,557 common units under the program for aggregate gross proceeds of \$228.5 million. After taking into account applicable costs, these transactions result in net proceeds of \$226.5 million, of which \$214.2 million was received as of June 30, 2013. After taking into account the aggregate sale price of common units sold under this program through June 30, 2013, we have the capacity to issue additional common units under this program up to an aggregate sale price of \$566.1 million.

We also have registration statements on file with the SEC collectively authorizing the issuance of up to 70,000,000 of our common units in connection with a distribution reinvestment plan (or “DRIP”). The DRIP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of our common units they own by reinvesting the quarterly cash distributions they would otherwise receive from us into the purchase of additional new common units. During the six months ended June 30, 2012, we issued 1,198,552 common units, which generated net proceeds of \$58.0 million. We issued 2,359,089 common units under our DRIP during the six months ended June 30, 2013, which generated net proceeds of \$129.8 million. After taking into account the number of common units issued under the DRIP through June 30, 2013, we may issue an additional 21,134,203 common units under this plan.

In January 2013, affiliates of privately held EPCO, which own our general partner and approximately 37.0% of our limited partner interests at June 30, 2013, expressed their willingness to purchase at least \$100 million of our common units during 2013 through our DRIP. During the six months ended June 30, 2013, these EPCO affiliates reinvested \$50.0 million, resulting in the issuance of 908,217 common units under our DRIP (this amount being a component of the 2,359,089 common units issued in total under the DRIP during the first six months of 2013). In August 2013, these affiliates reinvested an additional \$25.0 million under the DRIP.

In addition to the DRIP, we have a registration statement on file with the SEC authorizing the issuance of up to 440,879 of our common units in connection with an employee unit purchase plan (or “EUPP”). During the six months ended June 30, 2012, we issued 72,057 common units, which generated net proceeds of \$3.7 million. We issued 81,695 common units under our EUPP during the six months ended June 30, 2013, which generated net proceeds of \$4.8 million. After taking into account the number of common units issued under the EUPP through June 30, 2013, we may issue an additional 214,341 common units under this plan.

The net cash proceeds we received from the issuance of common units during the six months ended June 30, 2013 were used to temporarily reduce amounts outstanding under EPO’s Multi-Year Revolving Credit Facility and commercial paper program and for general company purposes.

A total of 1,830,010 restricted common unit awards granted to employees of EPCO vested and converted to common units during the six months ended June 30, 2013. Of this amount, 614,191 were sold back to us by employees to cover related withholding tax requirements. The total cost of these treasury unit purchases was approximately \$35.8 million. We cancelled such treasury units immediately upon acquisition. For additional information regarding our equity-based awards, see Note 3.

Class B units. In October 2009, we issued 4,520,431 Class B units to a privately held affiliate of EPCO in connection with the TEPPCO Merger. The Class B units were entitled to vote together with our common units as a single class on partnership matters and generally had the same rights and privileges as our common units, except that the Class B units were not entitled to receive regular quarterly cash distributions until they automatically converted into an equal number of common units on August 8, 2013.

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

Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) primarily reflects the effective portion of the gain or loss on derivative instruments designated and qualified as cash flow hedges. Gain or loss amounts related to cash flow hedges recorded in accumulated other comprehensive income (loss) are reclassified to 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) is immediately reclassified into earnings.

The following table presents reclassifications out of accumulated other comprehensive income (loss) into net income during the three and six months ended June 30, 2013:

	Location	For the Three Months Ended June 30, 2013	For the Six Months Ended June 30, 2013
Losses (gains) on cash flow hedges:			
Interest rate derivatives	Interest expense	\$ 7.8	\$ 13.7
Commodity derivatives	Revenue	(7.2)	0.5
Commodity derivatives	Operating costs and expenses	--	(0.4)
Total		<u>\$ 0.6</u>	<u>\$ 13.8</u>

Noncontrolling Interests

Noncontrolling interests as presented on our Unaudited Condensed Consolidated Financial Statements represent third party ownership interests in joint ventures that we consolidate for financial reporting purposes, including Tri-States NGL Pipeline L.L.C., Independence Hub LLC, Rio Grande Pipeline Company, Wilprise Pipeline Company LLC and Enterprise EF78 LLC.

In June 2013, we formed a joint venture, Enterprise EF78 LLC, with Western Gas Partners, LP (“Western Gas”) involving two NGL fractionators that are under construction at our complex in Mont Belvieu, Texas (i.e., NGL fractionators seven and eight). We own 75% of the joint venture’s membership interests and consolidate the joint venture. Western Gas acquired a 25% noncontrolling interest in the joint venture for an initial contribution of \$90.2 million, which is reflected as a contribution from noncontrolling interests on our Unaudited Statements of Consolidated Cash Flows. NGL fractionators seven and eight are expected to begin operations in the fourth quarter of 2013.

Cash Distributions

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

	Distribution Per Common Unit	Record Date	Payment Date
2013			
1st Quarter	\$0.67	04/30/13	05/07/13
2nd Quarter	\$0.68	07/31/13	08/07/13

In November 2010, we completed our merger with Enterprise GP Holdings L.P. (the “Holdings Merger”). In connection with the Holdings Merger, a privately held affiliate of EPCO agreed to temporarily waive the regular quarterly cash distributions it would otherwise receive from us with respect to a certain number of our common units it owns (the “Designated Units”). Distributions paid during 2013 exclude 23,700,000 Designated Units. Distributions to be paid, if any, during 2014 and 2015 will exclude 22,560,000 Designated Units and 17,690,000 Designated Units, respectively.

As previously noted, 4,520,431 Class B units automatically converted into an equal number of distribution-bearing common units on August 8, 2013.

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

Note 11. Business Segments

We have five reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services; and (v) Petrochemical & Refined Products Services. Our business segments are generally organized and managed according to the types of services rendered (or technologies employed) and products produced and/or sold.

All activities included in our former sixth reportable business segment, Other Investments, ceased on January 18, 2012, which was the date we discontinued using the equity method to account for our previously held investment in Energy Transfer Equity. See Note 7 for information regarding the liquidation of our investment in Energy Transfer Equity.

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by our management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income. Our non-GAAP financial measure of total segment gross operating margin should not be considered an alternative to GAAP operating income.

We define total segment gross operating margin as operating income before: (i) depreciation, amortization and accretion expenses; (ii) non-cash asset impairment charges; (iii) gains and losses attributable to asset sales and insurance recoveries; and (iv) 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, income taxes, the cumulative effect of changes in accounting principles and extraordinary charges. Gross operating margin is presented on a 100% basis before any allocation of earnings to noncontrolling interests.

We include equity in income of unconsolidated affiliates in our measurement of segment gross operating margin and operating income. Equity investments with industry partners are a significant component of our business strategy. They are a means by which we conduct our operations to align our interests with those of customers and/or suppliers. This method of operation enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed. Many of these businesses perform supporting or complementary roles to our other midstream business operations.

Segment revenues include intersegment and intrasegment transactions, which are generally based on transactions made at market-based rates. Our consolidated revenues reflect the elimination of intercompany transactions.

Segment assets consist of property, plant and equipment, investments in unconsolidated affiliates, intangible assets and goodwill. The carrying values of such amounts are assigned to each segment based on each asset's or investment's principal operations and contribution to the gross operating margin of that particular segment. Since construction-in-progress amounts (a component of property, plant and equipment) generally do not contribute to segment gross operating margin, such amounts are excluded from segment asset totals until the underlying assets are placed in service. Intangible assets and goodwill are assigned to each segment based on the classification of the assets to which they relate.

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

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
Revenues	\$ 11,149.3	\$ 9,789.8	\$ 22,532.4	\$ 21,042.3
Less: Operating costs and expenses	(10,367.2)	(9,009.5)	(20,787.6)	(19,476.7)
Add: Equity in income of unconsolidated affiliates	37.6	11.3	82.1	21.2
Amounts included in operating costs and expenses:				
Depreciation, amortization and accretion	289.7	261.3	566.5	515.9
Non-cash asset impairment charges	27.1	9.1	38.1	14.5
Losses (gains) attributable to asset sales and insurance recoveries	5.7	(29.0)	(58.2)	(31.5)
Total segment gross operating margin	<u>\$ 1,142.2</u>	<u>\$ 1,033.0</u>	<u>\$ 2,373.3</u>	<u>\$ 2,085.7</u>

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
Total segment gross operating margin	\$ 1,142.2	\$ 1,033.0	\$ 2,373.3	\$ 2,085.7
<i>Adjustments to reconcile total segment gross operating margin to operating income:</i>				
Amounts included in operating costs and expenses:				
Depreciation, amortization and accretion	(289.7)	(261.3)	(566.5)	(515.9)
Non-cash asset impairment charges	(27.1)	(9.1)	(38.1)	(14.5)
Gains (losses) attributable to asset sales and insurance recoveries	(5.7)	29.0	58.2	31.5
General and administrative costs	(45.5)	(42.5)	(95.0)	(88.8)
Operating income	<u>774.2</u>	<u>749.1</u>	<u>1,731.9</u>	<u>1,498.0</u>
Other expense, net	(200.5)	(173.4)	(396.5)	(301.2)
Income before income taxes	<u>\$ 573.7</u>	<u>\$ 575.7</u>	<u>\$ 1,335.4</u>	<u>\$ 1,196.8</u>

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

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

	Reportable Business Segments							Consolidated Total
	NGL Pipelines & Services	Onshore Natural Gas Pipelines & Services	Onshore Crude Oil Pipelines & Services	Offshore Pipelines & Services	Petrochemical & Refined Products Services	Other Investments	Adjustments and Eliminations	
Revenues from third parties:								
Three months ended June 30, 2013	\$ 3,504.7	\$ 953.0	\$ 5,129.5	\$ 39.3	\$ 1,516.1	\$ --	\$ --	\$ 11,142.6
Three months ended June 30, 2012	3,327.9	700.9	4,188.7	47.5	1,499.2	--	--	9,764.2
Six months ended June 30, 2013	7,455.4	1,827.2	9,922.7	79.8	3,234.7	--	--	22,519.8
Six months ended June 30, 2012	7,682.0	1,505.8	8,662.3	101.9	3,033.9	--	--	20,985.9
Revenues from related parties:								
Three months ended June 30, 2013	0.2	4.5	--	2.0	--	--	--	6.7
Three months ended June 30, 2012	4.6	19.5	--	1.5	--	--	--	25.6
Six months ended June 30, 2013	0.5	8.0	--	4.1	--	--	--	12.6
Six months ended June 30, 2012	5.0	48.2	--	3.2	--	--	--	56.4
Intersegment and intrasegment revenues:								
Three months ended June 30, 2013	2,380.4	254.9	2,717.0	4.2	394.2	--	(5,750.7)	--
Three months ended June 30, 2012	2,276.5	179.0	1,735.5	1.7	438.7	--	(4,631.4)	--
Six months ended June 30, 2013	5,089.4	511.1	4,741.7	6.2	816.3	--	(11,164.7)	--
Six months ended June 30, 2012	5,094.7	402.7	3,466.4	5.0	878.6	--	(9,847.4)	--
Total revenues:								
Three months ended June 30, 2013	5,885.3	1,212.4	7,846.5	45.5	1,910.3	--	(5,750.7)	11,149.3
Three months ended June 30, 2012	5,609.0	899.4	5,924.2	50.7	1,937.9	--	(4,631.4)	9,789.8
Six months ended June 30, 2013	12,545.3	2,346.3	14,664.4	90.1	4,051.0	--	(11,164.7)	22,532.4
Six months ended June 30, 2012	12,781.7	1,956.7	12,128.7	110.1	3,912.5	--	(9,847.4)	21,042.3
Equity in income (loss) of unconsolidated affiliates:								
Three months ended June 30, 2013	3.8	0.9	30.1	8.7	(5.9)	--	--	37.6
Three months ended June 30, 2012	3.8	1.2	3.6	4.1	(1.4)	--	--	11.3
Six months ended June 30, 2013	7.7	1.9	66.7	15.1	(9.3)	--	--	82.1
Six months ended June 30, 2012	9.0	2.6	4.1	11.0	(7.9)	2.4	--	21.2
Gross operating margin:								
Three months ended June 30, 2013	544.9	197.7	197.2	39.7	162.7	--	--	1,142.2
Three months ended June 30, 2012	565.8	175.8	95.8	38.3	157.3	--	--	1,033.0
Six months ended June 30, 2013	1,137.4	388.5	433.6	80.2	333.6	--	--	2,373.3
Six months ended June 30, 2012	1,220.7	382.0	135.1	90.4	255.1	2.4	--	2,085.7
Property, plant and equipment, net: (see Note 6)								
At June 30, 2013	9,195.8	8,925.8	1,426.2	1,277.6	2,636.0	--	2,104.7	25,566.1
At December 31, 2012	8,494.8	8,950.1	1,385.9	1,343.0	2,559.5	--	2,113.1	24,846.4
Investments in unconsolidated affiliates: (see Note 7)								
At June 30, 2013	515.5	24.4	783.1	543.3	72.5	--	--	1,938.8
At December 31, 2012	324.6	24.9	493.8	479.0	72.3	--	--	1,394.6
Intangible assets, net: (see Note 8)								
At June 30, 2013	301.5	1,043.2	5.2	60.2	103.1	--	--	1,513.2
At December 31, 2012	320.6	1,067.9	5.9	66.2	106.2	--	--	1,566.8
Goodwill: (see Note 8)								
At June 30, 2013	341.2	296.3	305.1	82.1	1,055.3	--	--	2,080.0
At December 31, 2012	341.2	296.3	311.2	82.1	1,056.0	--	--	2,086.8
Segment assets:								
At June 30, 2013	10,354.0	10,289.7	2,519.6	1,963.2	3,866.9	--	2,104.7	31,098.1
At December 31, 2012	9,481.2	10,339.2	2,196.8	1,970.3	3,794.0	--	2,113.1	29,894.6

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

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
NGL Pipelines & Services:				
Sales of NGLs and related products	\$ 3,235.9	\$ 3,133.9	\$ 6,901.5	\$ 7,249.2
Midstream asset services	269.0	198.6	554.4	437.8
Total	3,504.9	3,332.5	7,455.9	7,687.0
Onshore Natural Gas Pipelines & Services:				
Sales of natural gas	723.9	510.8	1,363.4	1,083.4
Midstream asset services	233.6	209.6	471.8	470.6
Total	957.5	720.4	1,835.2	1,554.0
Onshore Crude Oil Pipelines & Services:				
Sales of crude oil	5,057.4	4,174.0	9,800.2	8,621.6
Midstream asset services	72.1	14.7	122.5	40.7
Total	5,129.5	4,188.7	9,922.7	8,662.3
Offshore Pipelines & Services:				
Sales of natural gas	0.1	--	0.2	0.1
Sales of crude oil	(0.1)	--	2.2	1.4
Midstream asset services	41.3	49.0	81.5	103.6
Total	41.3	49.0	83.9	105.1
Petrochemical & Refined Products Services:				
Sales of petrochemicals and refined products	1,334.2	1,316.8	2,881.4	2,668.0
Midstream asset services	181.9	182.4	353.3	365.9
Total	1,516.1	1,499.2	3,234.7	3,033.9
Total consolidated revenues	\$ 11,149.3	\$ 9,789.8	\$ 22,532.4	\$ 21,042.3
Consolidated costs and expenses				
Operating costs and expenses:				
Cost of sales	\$ 9,458.3	\$ 8,195.2	\$ 19,150.8	\$ 17,861.0
Other operating costs and expenses (1)	586.4	572.9	1,090.4	1,116.8
Depreciation, amortization and accretion	289.7	261.3	566.5	515.9
Losses (gains) attributable to asset sales and insurance recoveries	5.7	(29.0)	(58.2)	(31.5)
Non-cash asset impairment charges	27.1	9.1	38.1	14.5
General and administrative costs	45.5	42.5	95.0	88.8
Total consolidated costs and expenses	\$ 10,412.7	\$ 9,052.0	\$ 20,882.6	\$ 19,565.5

(1) Represents cost of operating our plants, pipelines and other fixed assets, excluding depreciation, amortization and accretion charges.

Period-to-period fluctuations in our product sales revenues and related cost of sales amounts are explained in part by changes in energy commodity prices. In general, lower energy commodity prices result in a decrease in our revenues attributable to product sales; however, these lower commodity prices also decrease the associated cost of sales as purchase costs decline. The same correlation would be true in the case of higher energy commodity sales prices and purchase costs.

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

Note 12. Related Party Transactions

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
Revenues – related parties:				
Unconsolidated affiliates	\$ 6.7	\$ 25.6	\$ 12.6	\$ 56.4
Costs and expenses – related parties:				
EPCO and affiliates	\$ 222.9	\$ 240.1	\$ 435.6	\$ 406.1
Unconsolidated affiliates	29.3	7.2	60.6	12.3
Total	<u>\$ 252.2</u>	<u>\$ 247.3</u>	<u>\$ 496.2</u>	<u>\$ 418.4</u>

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

	June 30, 2013	December 31, 2012
Accounts receivable – related parties:		
Unconsolidated affiliates	<u>\$ 19.8</u>	<u>\$ 2.5</u>
Accounts payable – related parties:		
EPCO and affiliates	\$ 116.3	\$ 102.4
Unconsolidated affiliates	25.7	24.7
Total	<u>\$ 142.0</u>	<u>\$ 127.1</u>

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 privately held affiliates (including Enterprise GP, our general partner), which are not a part of our consolidated group of companies. At June 30, 2013, EPCO and its privately held affiliates (including Dan Duncan LLC and certain Duncan family trusts, the beneficiaries of which include the estate of Dan L. Duncan) beneficially owned the following limited partner interests in us:

Number of Units Beneficially Owned	Percentage of Total Units Outstanding
340,039,098 (1)	37.0%

(1) Includes 4,520,431 Class B units that converted to an equal number of distribution-bearing common units on August 8, 2013 (see Note 10).

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 also separate from those of EPCO and its other affiliates. EPCO and its privately held affiliates depend on the cash distributions they receive from us and other investments to fund their other activities and to meet their debt obligations. During the six months ended June 30, 2013 and 2012, we paid EPCO and its privately held affiliates cash distributions totaling \$397.5 million and \$369.6 million, respectively.

From time-to-time, EPCO and its privately held affiliates elect to reinvest a portion of the cash distributions they would otherwise receive from us into the purchase of additional common units under our DRIP. See Note 10 for additional information regarding these reinvestments, including an expected reinvestment of up to \$100 million in the aggregate during 2013.

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

We have no employees. All of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to the ASA or by other service providers.

The following table presents our costs and expenses attributable to the ASA and other related party transactions with EPCO for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
Operating costs and expenses	\$ 193.1	\$ 213.6	\$ 374.2	\$ 356.3
General and administrative expenses	29.8	26.5	61.4	49.8
Total costs and expenses	<u>\$ 222.9</u>	<u>\$ 240.1</u>	<u>\$ 435.6</u>	<u>\$ 406.1</u>

Note 13. Earnings Per Unit

Basic earnings per unit is computed by dividing net income or loss attributable to our limited partners by the weighted-average number of our distribution-bearing units outstanding during a period, which excludes the Designated Units (see Note 10) to the extent such units do not participate in the distributions to be paid with respect to such period.

Diluted earnings per unit is computed by dividing net income or loss attributable to our limited partners 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").

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

	For the Three Months Ended June 30		For the Six Months Ended June 30,	
	2013	2012	2013	2012
BASIC EARNINGS PER UNIT				
Numerator:				
Net income attributable to limited partners	\$ 552.5	\$ 566.3	\$ 1,306.0	\$ 1,217.6
Denominator:				
Weighted-average number of distribution-bearing common units outstanding	889.1	857.9	885.4	857.3
Basic earnings per unit:				
Net income attributable to limited partners	<u>\$ 0.62</u>	<u>\$ 0.66</u>	<u>\$ 1.48</u>	<u>\$ 1.42</u>
DILUTED EARNINGS PER UNIT				
Numerator:				
Net income attributable to limited partners	\$ 552.5	\$ 566.3	\$ 1,306.0	\$ 1,217.6
Denominator:				
Weighted-average number of units outstanding:				
Distribution-bearing common units	889.1	857.9	885.4	857.3
Class B units	4.5	4.5	4.5	4.5
Designated Units	23.7	26.1	23.7	26.1
Incremental option units	1.2	1.4	1.2	1.4
Total	<u>918.5</u>	<u>889.9</u>	<u>914.8</u>	<u>889.3</u>
Diluted earnings per unit:				
Net income attributable to limited partners	<u>\$ 0.60</u>	<u>\$ 0.64</u>	<u>\$ 1.43</u>	<u>\$ 1.37</u>

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

Note 14. Commitments and Contingencies

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. We will vigorously defend the partnership in litigation matters.

Management has regular quarterly litigation reviews, including updates from legal counsel, to assess the possible need for accounting recognition and disclosure of these contingencies. We accrue an undiscounted liability for those contingencies where the loss is probable and the amount can be reasonably estimated. If a range of probable loss amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum amount in 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 the likelihood of loss is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is reasonably possible and the impact would be material to our consolidated financial statements, we disclose the nature of the contingency and, where feasible, an estimate of the possible loss or range of loss. Based on a consideration of all relevant known facts and circumstances, we do not believe that the ultimate outcome of any currently pending litigation directed against us will have a material impact on our consolidated financial statements either individually at the claim level or in the aggregate.

At June 30, 2013 and December 31, 2012, our accruals for litigation contingencies were \$4.9 million and \$4.4 million, respectively, and were recorded in our Unaudited Condensed 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 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.

Contractual Obligations

Scheduled Maturities of Debt. With the exception of routine fluctuations in the balances of our Multi-Year Revolving Credit Facility and commercial paper notes, the issuance of Senior Notes HH and II in March 2013 and the scheduled repayment of maturing debt obligations, there have been no significant changes in our consolidated debt obligations since those reported in our 2012 Form 10-K. See Note 9 for additional information regarding our consolidated debt obligations.

Operating Lease Obligations. Consolidated lease and rental expense was \$23.3 million and \$22.7 million during the second quarters of 2013 and 2012, respectively. For the six months ended June 30, 2013 and 2012, consolidated lease and rental expense was \$45.3 million and \$45.1 million, respectively. There have been no material changes in our operating lease commitments since those reported in our 2012 Form 10-K.

Purchase Obligations. There have been no material changes in our consolidated purchase obligations since those reported in our 2012 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, 2013, our contingent claims against such parties were \$41.8 million and claims against us were \$43.4 million. These matters are in various stages of assessment and the ultimate outcome of such disputes cannot be reasonably estimated at this time. With respect to claims against us, we believe that the likelihood of a material loss resulting from such claims is remote. Accordingly, no accruals for loss contingencies related to these matters have been recorded.

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

Note 15. 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.

We elected to forego windstorm coverage for our Gulf of Mexico offshore assets during the 2013 Atlantic hurricane season, which extends from June 1 through November 30. The combination of increasingly high deductibles and proposed premiums resulted in such coverage being uneconomic to us. Although EPCO's coverage does not provide any windstorm coverage for our offshore assets during the annual policy period that began on June 1, 2013, producers affiliated with our Independence Hub and Marco Polo platforms will continue to provide certain levels of physical damage windstorm coverage for each of these key offshore assets.

West Storage Claims

We received \$8.8 million of nonrefundable cash insurance proceeds during the six months ended June 30, 2013 attributable to property damage claims we filed in connection with a February 2011 NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility. During the three and six months ended June 30, 2012, we collected \$27.7 million of such proceeds. We did not receive any proceeds related to these claims during the second quarter of 2013. We remain in negotiation with our insurance carriers regarding collection of the remaining West Storage claims, which are currently estimated at \$91.9 million.

Operating income during the six months ended June 30, 2013 includes \$8.8 million of gains related to these insurance recoveries. Operating income for the three and six months ended June 30, 2012 includes \$27.7 million of such gains. To the extent that additional nonrefundable cash insurance proceeds related to this incident are received, we expect to record gains equal to such proceeds.

Note 16. Supplemental Cash Flow Information

The following table presents the net effect of changes in our operating accounts for the periods indicated:

	For the Six Months Ended June 30,	
	2013	2012
Decrease (increase) in:		
Accounts receivable – trade	\$ (312.6)	\$ 785.5
Accounts receivable – related parties	(17.2)	35.7
Inventories	(255.1)	(20.8)
Prepaid and other current assets	(42.2)	(13.9)
Other assets	0.8	(53.7)
Increase (decrease) in:		
Accounts payable – trade	35.3	(45.7)
Accounts payable – related parties	15.0	(141.3)
Accrued product payables	195.7	(880.2)
Accrued interest	2.8	1.0
Other current liabilities	(16.5)	84.1
Other liabilities	(15.2)	(31.0)
Net effect of changes in operating accounts	<u>\$ (409.2)</u>	<u>\$ (280.3)</u>

We incurred liabilities for construction in progress that had not been paid at June 30, 2013 and December 31, 2012 of \$218.1 million and \$221.7 million, respectively. Such amounts are not included under the caption "Capital expenditures" on the Unaudited Condensed Statements of Consolidated Cash Flows.

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

The following table presents our cash proceeds from asset sales and insurance recoveries for the periods indicated:

	For the Six Months Ended June 30,	
	2013	2012
Sale of Energy Transfer Equity common units (see Note 7)	\$ --	\$ 1,095.3
Sale of Stratton Ridge-to-Mont Belvieu segment of Seminole Pipeline (see Note 6)	86.9	--
Sale of chemical trucking assets (see Note 6)	29.5	--
Sale of lubrication oil and specialty chemical distribution assets (see Note 6)	35.3	--
Marine transportation assets (see Note 6)	14.9	2.4
Insurance recoveries attributable to West Storage claims (see Note 15)	8.8	27.7
Other cash proceeds	23.8	31.3
Total	<u>\$ 199.2</u>	<u>\$ 1,156.7</u>

The following table presents gains (losses) attributable to asset sales and insurance recoveries for the periods indicated:

	For the Six Months Ended June 30,	
	2013	2012
Sale of Energy Transfer Equity common units (see Note 7) (1)	\$ --	\$ 68.8
Sale of Stratton Ridge-to-Mont Belvieu segment of Seminole Pipeline (see Note 6) (2)	52.5	--
Insurance recoveries attributable to West Storage claims (see Note 15) (2)	8.8	27.7
Sale of lubrication oil and specialty chemical distribution assets (see Note 6) (2)	6.7	--
Marine transportation assets (see Note 6) (2)	(6.7)	(3.1)
Sale of chemical trucking assets (see Note 6) (2)	(0.5)	--
Other gains (losses), net (2)	(2.6)	6.9
Total	<u>\$ 58.2</u>	<u>\$ 100.3</u>

- (1) This amount is a component of "Other income" as presented on our Unaudited Condensed Statements of Consolidated Operations.
- (2) These amounts are a component of "Operating costs and expenses" as presented on our Unaudited Condensed Statements of Consolidated Operations.

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. Enterprise Products Partners L.P. directly or indirectly owns 100% of EPO.

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 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 and unconditional 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.

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

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Balance Sheet
June 30, 2013

	EPO and Subsidiaries				Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
ASSETS	Subsidiary Issuer (EPO)	Other Subsidiaries (Non- guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries			
Current assets:							
Cash and cash equivalents and restricted cash	\$ 39.6	\$ 42.5	\$ (10.5)	\$ 71.6	\$ --	\$ --	\$ 71.6
Accounts receivable – trade, net	1,406.1	3,247.5	(2.1)	4,651.5	--	--	4,651.5
Accounts receivable – related parties	292.7	1,375.8	(1,619.7)	48.8	--	(29.0)	19.8
Inventories	1,170.2	242.2	(1.0)	1,411.4	--	--	1,411.4
Prepaid and other current assets	240.0	202.8	(17.4)	425.4	0.3	--	425.7
Total current assets	3,148.6	5,110.8	(1,650.7)	6,608.7	0.3	(29.0)	6,580.0
Property, plant and equipment, net	1,719.3	23,844.8	2.0	25,566.1	--	--	25,566.1
Investments in unconsolidated affiliates	29,590.0	2,459.1	(30,110.3)	1,938.8	14,185.1	(14,185.1)	1,938.8
Intangible assets, net	77.7	1,435.5	--	1,513.2	--	--	1,513.2
Goodwill	458.9	1,621.1	--	2,080.0	--	--	2,080.0
Other assets	130.0	74.8	(6.1)	198.7	0.1	--	198.8
Total assets	\$ 35,124.5	\$ 34,546.1	\$ (31,765.1)	\$ 37,905.5	\$ 14,185.5	\$ (14,214.1)	\$ 37,876.9
LIABILITIES AND EQUITY							
Current liabilities:							
Current maturities of debt	\$ 540.0	\$ --	\$ --	\$ 540.0	\$ --	\$ --	\$ 540.0
Accounts payable – trade	230.4	557.5	(10.5)	777.4	--	--	777.4
Accounts payable – related parties	1,578.1	182.9	(1,619.6)	141.4	29.6	(29.0)	142.0
Accrued product payables	1,778.3	2,995.3	(3.2)	4,770.4	--	--	4,770.4
Accrued interest	303.5	0.1	--	303.6	--	--	303.6
Other current liabilities	71.1	286.3	(17.4)	340.0	--	(0.3)	339.7
Total current liabilities	4,501.4	4,022.1	(1,650.7)	6,872.8	29.6	(29.3)	6,873.1
Long-term debt	16,414.7	14.9	--	16,429.6	--	--	16,429.6
Deferred tax liabilities	25.6	16.8	(6.1)	36.3	--	0.9	37.2
Other long-term liabilities	10.0	174.2	--	184.2	--	--	184.2
Commitments and contingencies							
Equity:							
Partners' and other owners' equity	14,172.8	30,244.8	(30,257.5)	14,160.1	14,155.9	(14,160.1)	14,155.9
Noncontrolling interests	--	73.3	149.2	222.5	--	(25.6)	196.9
Total equity	14,172.8	30,318.1	(30,108.3)	14,382.6	14,155.9	(14,185.7)	14,352.8
Total liabilities and equity	\$ 35,124.5	\$ 34,546.1	\$ (31,765.1)	\$ 37,905.5	\$ 14,185.5	\$ (14,214.1)	\$ 37,876.9

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

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Balance Sheet
December 31, 2012

	EPO and Subsidiaries			Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non- guarantor)	EPO and Subsidiaries Eliminations and Adjustments				
ASSETS							
Current assets:							
Cash and cash equivalents and restricted cash	\$ 4.3	\$ 28.0	\$ (12.1)	\$ 20.2	\$ 0.2	\$ --	\$ 20.4
Accounts receivable – trade, net	1,585.2	2,768.7	(3.0)	4,350.9	--	--	4,350.9
Accounts receivable – related parties	180.5	1,372.8	(1,550.8)	2.5	(0.6)	0.6	2.5
Inventories	853.6	235.6	(0.8)	1,088.4	--	--	1,088.4
Prepaid and other current assets	154.9	231.8	(5.8)	380.9	--	--	380.9
Total current assets	2,778.5	4,636.9	(1,572.5)	5,842.9	(0.4)	0.6	5,843.1
Property, plant and equipment, net	1,673.6	23,170.8	2.0	24,846.4	--	--	24,846.4
Investments in unconsolidated affiliates	28,454.4	1,846.9	(28,906.7)	1,394.6	13,188.0	(13,188.0)	1,394.6
Intangible assets, net	78.5	1,488.3	--	1,566.8	--	--	1,566.8
Goodwill	458.9	1,627.9	--	2,086.8	--	--	2,086.8
Other assets	126.0	71.4	(0.9)	196.5	0.2	--	196.7
Total assets	\$ 33,569.9	\$ 32,842.2	\$ (30,478.1)	\$ 35,934.0	\$ 13,187.8	\$ (13,187.4)	\$ 35,934.4
LIABILITIES AND EQUITY							
Current liabilities:							
Current maturities of debt	\$ 1,516.7	\$ 29.9	\$ --	\$ 1,546.6	\$ --	\$ --	\$ 1,546.6
Accounts payable – trade	226.7	549.8	(12.1)	764.4	0.1	--	764.5
Accounts payable – related parties	1,584.2	92.9	(1,550.6)	126.5	--	0.6	127.1
Accrued product payables	1,851.8	2,628.4	(4.0)	4,476.2	--	--	4,476.2
Accrued interest	300.1	0.7	--	300.8	--	--	300.8
Other current liabilities	266.5	280.0	(5.8)	540.7	--	(0.2)	540.5
Total current liabilities	5,746.0	3,581.7	(1,572.5)	7,755.2	0.1	0.4	7,755.7
Long-term debt	14,640.2	15.0	--	14,655.2	--	--	14,655.2
Deferred tax liabilities	5.1	17.7	(0.9)	21.9	--	0.6	22.5
Other long-term liabilities	15.6	189.4	--	205.0	--	--	205.0
Commitments and contingencies							
Equity:							
Partners' and other owners' equity	13,163.0	28,963.7	(28,961.1)	13,165.6	13,187.7	(13,165.6)	13,187.7
Noncontrolling interests	--	74.7	56.4	131.1	--	(22.8)	108.3
Total equity	13,163.0	29,038.4	(28,904.7)	13,296.7	13,187.7	(13,188.4)	13,296.0
Total liabilities and equity	\$ 33,569.9	\$ 32,842.2	\$ (30,478.1)	\$ 35,934.0	\$ 13,187.8	\$ (13,187.4)	\$ 35,934.4

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, 2013

	EPO and Subsidiaries			Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non- guarantor)	EPO and Subsidiaries Eliminations and Adjustments				
Revenues	\$ 6,491.0	\$ 8,015.7	\$ (3,357.4)	\$ 11,149.3	\$ --	\$ --	\$ 11,149.3
Costs and expenses:							
Operating costs and expenses	6,326.6	7,398.1	(3,357.5)	10,367.2	--	--	10,367.2
General and administrative costs	7.4	37.4	--	44.8	0.7	--	45.5
Total costs and expenses	6,334.0	7,435.5	(3,357.5)	10,412.0	0.7	--	10,412.7
Equity in income of unconsolidated affiliates	612.3	42.9	(617.6)	37.6	553.2	(553.2)	37.6
Operating income	769.3	623.1	(617.5)	774.9	552.5	(553.2)	774.2
Other income (expense):							
Interest expense	(199.7)	(0.5)	--	(200.2)	--	--	(200.2)
Other, net	0.1	(0.4)	--	(0.3)	--	--	(0.3)
Total other expense, net	(199.6)	(0.9)	--	(200.5)	--	--	(200.5)
Income before income taxes	569.7	622.2	(617.5)	574.4	552.5	(553.2)	573.7
Provision for income taxes	(17.5)	(2.9)	--	(20.4)	--	--	(20.4)
Net income	552.2	619.3	(617.5)	554.0	552.5	(553.2)	553.3
Net income attributable to noncontrolling interests	--	(0.4)	(1.3)	(1.7)	--	0.9	(0.8)
Net income attributable to entity	\$ 552.2	\$ 618.9	\$ (618.8)	\$ 552.3	\$ 552.5	\$ (552.3)	\$ 552.5

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
Three Months Ended June 30, 2012

	EPO and Subsidiaries			Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non- guarantor)	EPO and Subsidiaries Eliminations and Adjustments				
Revenues	\$ 6,033.6	\$ 6,696.0	\$ (2,939.8)	\$ 9,789.8	\$ --	\$ --	\$ 9,789.8
Costs and expenses:							
Operating costs and expenses	5,864.4	6,083.0	(2,937.9)	9,009.5	--	--	9,009.5
General and administrative costs	9.1	32.6	--	41.7	0.8	--	42.5
Total costs and expenses	5,873.5	6,115.6	(2,937.9)	9,051.2	0.8	--	9,052.0
Equity in income of unconsolidated affiliates	598.8	(51.0)	(536.5)	11.3	567.1	(567.1)	11.3
Operating income	758.9	529.4	(538.4)	749.9	566.3	(567.1)	749.1
Other income (expense):							
Interest expense	(185.7)	(0.9)	--	(186.6)	--	--	(186.6)
Other, net	--	13.2	--	13.2	--	--	13.2
Total other expense, net	(185.7)	12.3	--	(173.4)	--	--	(173.4)
Income before income taxes	573.2	541.7	(538.4)	576.5	566.3	(567.1)	575.7
Provision for income taxes	(4.6)	(3.7)	--	(8.3)	--	(0.2)	(8.5)
Net income	568.6	538.0	(538.4)	568.2	566.3	(567.3)	567.2
Net loss (income) attributable to noncontrolling interests	--	40.2	(41.7)	(1.5)	--	0.6	(0.9)
Net income attributable to entity	\$ 568.6	\$ 578.2	\$ (580.1)	\$ 566.7	\$ 566.3	\$ (566.7)	\$ 566.3

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, 2013

	EPO and Subsidiaries			Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non- guarantor)	EPO and Subsidiaries Eliminations and Adjustments				
Revenues	\$ 13,846.5	\$ 15,456.1	\$ (6,770.2)	\$ 22,532.4	\$ --	\$ --	\$ 22,532.4
Costs and expenses:							
Operating costs and expenses	13,470.5	14,087.3	(6,770.2)	20,787.6	--	--	20,787.6
General and administrative costs	12.1	82.0	--	94.1	0.9	--	95.0
Total costs and expenses	13,482.6	14,169.3	(6,770.2)	20,881.7	0.9	--	20,882.6
Equity in income of unconsolidated affiliates	1,359.0	94.1	(1,371.0)	82.1	1,306.9	(1,306.9)	82.1
Operating income	1,722.9	1,380.9	(1,371.0)	1,732.8	1,306.0	(1,306.9)	1,731.9
Other income (expense):							
Interest expense	(395.0)	(1.1)	--	(396.1)	--	--	(396.1)
Other, net	0.2	(0.6)	--	(0.4)	--	--	(0.4)
Total other expense, net	(394.8)	(1.7)	--	(396.5)	--	--	(396.5)
Income before income taxes	1,328.1	1,379.2	(1,371.0)	1,336.3	1,306.0	(1,306.9)	1,335.4
Provision for income taxes	(22.6)	(3.9)	--	(26.5)	--	(0.3)	(26.8)
Net income	1,305.5	1,375.3	(1,371.0)	1,309.8	1,306.0	(1,307.2)	1,308.6
Net income attributable to noncontrolling interests	--	(0.9)	(3.3)	(4.2)	--	1.6	(2.6)
Net income attributable to entity	\$ 1,305.5	\$ 1,374.4	\$ (1,374.3)	\$ 1,305.6	\$ 1,306.0	\$ (1,305.6)	\$ 1,306.0

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
Six Months Ended June 30, 2012

	EPO and Subsidiaries			Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non- guarantor)	EPO and Subsidiaries Eliminations and Adjustments				
Revenues	\$ 13,673.4	\$ 13,854.5	\$ (6,485.6)	\$ 21,042.3	\$ --	\$ --	\$ 21,042.3
Costs and expenses:							
Operating costs and expenses	13,274.2	12,686.6	(6,484.1)	19,476.7	--	--	19,476.7
General and administrative costs	24.5	63.3	--	87.8	1.0	--	88.8
Total costs and expenses	13,298.7	12,749.9	(6,484.1)	19,564.5	1.0	--	19,565.5
Equity in income of unconsolidated affiliates	1,193.3	27.4	(1,199.5)	21.2	1,218.6	(1,218.6)	21.2
Operating income	1,568.0	1,132.0	(1,201.0)	1,499.0	1,217.6	(1,218.6)	1,498.0
Other income (expense):							
Interest expense	(371.3)	(1.8)	--	(373.1)	--	--	(373.1)
Other, net	0.1	71.8	--	71.9	--	--	71.9
Total other expense, net	(371.2)	70.0	--	(301.2)	--	--	(301.2)
Income before income taxes	1,196.8	1,202.0	(1,201.0)	1,197.8	1,217.6	(1,218.6)	1,196.8
Benefit from income taxes	22.4	3.7	--	26.1	--	(0.2)	25.9
Net income	1,219.2	1,205.7	(1,201.0)	1,223.9	1,217.6	(1,218.8)	1,222.7
Net income attributable to noncontrolling interests	--	(4.2)	(2.0)	(6.2)	--	1.1	(5.1)
Net income attributable to entity	\$ 1,219.2	\$ 1,201.5	\$ (1,203.0)	\$ 1,217.7	\$ 1,217.6	\$ (1,217.7)	\$ 1,217.6

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

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Comprehensive Income
Three Months Ended June 30, 2013

	EPO and Subsidiaries			Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non- guarantor)	EPO and Subsidiaries Eliminations and Adjustments				
Comprehensive income	\$ 575.1	\$ 631.6	\$ (617.6)	\$ 589.1	\$ 587.6	\$ (588.3)	\$ 588.4
Comprehensive income attributable to noncontrolling interests	--	(0.4)	(1.3)	(1.7)	--	0.9	(0.8)
Comprehensive income attributable to entity	<u>\$ 575.1</u>	<u>\$ 631.2</u>	<u>\$ (618.9)</u>	<u>\$ 587.4</u>	<u>\$ 587.6</u>	<u>\$ (587.4)</u>	<u>\$ 587.6</u>

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Comprehensive Income
Three Months Ended June 30, 2012

	EPO and Subsidiaries			Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non- guarantor)	EPO and Subsidiaries Eliminations and Adjustments				
Comprehensive income	\$ 503.8	\$ 625.9	\$ (538.4)	\$ 591.3	\$ 589.4	\$ (590.4)	\$ 590.3
Comprehensive loss (income) attributable to noncontrolling interests	--	40.2	(41.7)	(1.5)	--	0.6	(0.9)
Comprehensive income attributable to entity	<u>\$ 503.8</u>	<u>\$ 666.1</u>	<u>\$ (580.1)</u>	<u>\$ 589.8</u>	<u>\$ 589.4</u>	<u>\$ (589.8)</u>	<u>\$ 589.4</u>

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Comprehensive Income
Six Months Ended June 30, 2013

	EPO and Subsidiaries			Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non- guarantor)	EPO and Subsidiaries Eliminations and Adjustments				
Comprehensive income	\$ 1,328.1	\$ 1,360.0	\$ (1,371.0)	\$ 1,317.1	\$ 1,313.4	\$ (1,314.5)	\$ 1,316.0
Comprehensive income attributable to noncontrolling interests	--	(0.9)	(3.3)	(4.2)	--	1.6	(2.6)
Comprehensive income attributable to entity	<u>\$ 1,328.1</u>	<u>\$ 1,359.1</u>	<u>\$ (1,374.3)</u>	<u>\$ 1,312.9</u>	<u>\$ 1,313.4</u>	<u>\$ (1,312.9)</u>	<u>\$ 1,313.4</u>

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Comprehensive Income
Six Months Ended June 30, 2012

	EPO and Subsidiaries			Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non- guarantor)	EPO and Subsidiaries Eliminations and Adjustments				
Comprehensive income	\$ 1,183.6	\$ 1,274.0	\$ (1,201.0)	\$ 1,256.6	\$ 1,250.3	\$ (1,251.5)	\$ 1,255.4
Comprehensive income attributable to noncontrolling interests	--	(4.2)	(2.0)	(6.2)	--	1.1	(5.1)
Comprehensive income attributable to entity	<u>\$ 1,183.6</u>	<u>\$ 1,269.8</u>	<u>\$ (1,203.0)</u>	<u>\$ 1,250.4</u>	<u>\$ 1,250.3</u>	<u>\$ (1,250.4)</u>	<u>\$ 1,250.3</u>

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, 2013

	EPO and Subsidiaries			Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non- guarantor)	EPO and Subsidiaries Eliminations and Adjustments				
Operating activities:							
Net income	\$ 1,305.5	\$ 1,375.3	\$ (1,371.0)	\$ 1,309.8	\$ 1,306.0	\$ (1,307.2)	\$ 1,308.6
<i>Reconciliation of net income to net cash flows provided by operating activities:</i>							
Depreciation, amortization and accretion	69.8	530.0	--	599.8	--	--	599.8
Equity in income of unconsolidated affiliates	(1,359.0)	(94.1)	1,371.0	(82.1)	(1,306.9)	1,306.9	(82.1)
Distributions received from unconsolidated affiliates	2,432.2	116.8	(2,429.7)	119.3	1,195.6	(1,195.6)	119.3
Net effect of changes in operating accounts and other operating activities	(744.5)	337.1	1.5	(405.9)	21.6	(30.4)	(414.7)
Net cash flows provided by operating activities	1,704.0	2,265.1	(2,428.2)	1,540.9	1,216.3	(1,226.3)	1,530.9
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(129.3)	(1,303.1)	--	(1,432.4)	--	--	(1,432.4)
Proceeds from asset sales and insurance recoveries	12.6	186.6	--	199.2	--	--	199.2
Other investing activities	(1,798.7)	(361.1)	1,590.4	(569.4)	(835.8)	835.8	(569.4)
Cash used in investing activities	(1,915.4)	(1,477.6)	1,590.4	(1,802.6)	(835.8)	835.8	(1,802.6)
Financing activities:							
Borrowings under debt agreements	7,064.5	--	--	7,064.5	--	--	7,064.5
Repayments of debt	(6,251.7)	(29.9)	--	(6,281.6)	--	--	(6,281.6)
Cash distributions paid to partners	(1,226.3)	(2,434.4)	2,434.4	(1,226.3)	(1,171.9)	1,226.3	(1,171.9)
Cash distributions paid to noncontrolling interests	--	--	(4.7)	(4.7)	--	--	(4.7)
Cash contributions from noncontrolling interests	--	--	95.9	95.9	--	--	95.9
Net cash proceeds from issuance of common units	--	--	--	--	835.4	--	835.4
Cash contributions from owners	835.8	1,686.2	(1,686.2)	835.8	--	(835.8)	--
Other financing activities	(192.6)	0.1	--	(192.5)	(44.2)	--	(236.7)
Cash provided by (used in) financing activities	229.7	(778.0)	839.4	291.1	(380.7)	390.5	300.9
Net change in cash and cash equivalents	18.3	9.5	1.6	29.4	(0.2)	--	29.2
Cash and cash equivalents, January 1	--	28.0	(12.1)	15.9	0.2	--	16.1
Cash and cash equivalents, June 30	\$ 18.3	\$ 37.5	\$ (10.5)	\$ 45.3	\$ --	\$ --	\$ 45.3

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

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Cash Flows
Six Months Ended June 30, 2012

	EPO and Subsidiaries			Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non- guarantor)	EPO and Subsidiaries Eliminations and Adjustments				
Operating activities:							
Net income	\$ 1,219.2	\$ 1,205.7	\$ (1,201.0)	\$ 1,223.9	\$ 1,217.6	\$ (1,218.8)	\$ 1,222.7
<i>Reconciliation of net income to net cash flows provided by operating activities:</i>							
Depreciation, amortization and accretion	66.4	472.0	(0.7)	537.7	--	--	537.7
Equity in income of unconsolidated affiliates	(1,193.3)	(27.4)	1,199.5	(21.2)	(1,218.6)	1,218.6	(21.2)
Distributions received from unconsolidated affiliates	1,589.2	40.0	(1,578.7)	50.5	1,082.4	(1,082.4)	50.5
Net effect of changes in operating accounts and other operating activities	(1,148.6)	722.3	(34.5)	(460.8)	9.2	0.2	(451.4)
Net cash flows provided by operating activities	532.9	2,412.6	(1,615.4)	1,330.1	1,090.6	(1,082.4)	1,338.3
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(83.5)	(1,719.6)	--	(1,803.1)	--	--	(1,803.1)
Proceeds from asset sales and insurance recoveries	1,104.8	51.9	--	1,156.7	--	--	1,156.7
Other investing activities	(961.9)	(81.9)	940.4	(103.4)	(60.4)	60.4	(103.4)
Cash provided by (used in) investing activities	59.4	(1,749.6)	940.4	(749.8)	(60.4)	60.4	(749.8)
Financing activities:							
Borrowings under debt agreements	2,414.6	--	--	2,414.6	--	--	2,414.6
Repayments of debt	(1,881.5)	(9.5)	--	(1,891.0)	--	--	(1,891.0)
Cash distributions paid to partners	(1,082.4)	(1,586.9)	1,586.9	(1,082.4)	(1,068.6)	1,082.4	(1,068.6)
Cash distributions paid to noncontrolling interests	--	--	(8.1)	(8.1)	--	--	(8.1)
Cash contributions from noncontrolling interests	--	--	5.9	5.9	--	--	5.9
Net cash proceeds from issuance of common units	--	--	--	--	61.5	--	61.5
Cash contributions from owners	60.4	946.4	(946.4)	60.4	--	(60.4)	--
Other financing activities	(85.0)	--	--	(85.0)	(23.1)	--	(108.1)
Cash used in financing activities	(573.9)	(650.0)	638.3	(585.6)	(1,030.2)	1,022.0	(593.8)
Net change in cash and cash equivalents	18.4	13.0	(36.7)	(5.3)	--	--	(5.3)
Cash and cash equivalents, January 1	9.7	21.3	(11.2)	19.8	--	--	19.8
Cash and cash equivalents, June 30	\$ 28.1	\$ 34.3	\$ (47.9)	\$ 14.5	\$ --	\$ --	\$ 14.5

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

For the three and six months ended June 30, 2013 and 2012.

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 and the Audited Consolidated 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, 2012, as filed on March 1, 2013 (the “2012 Form 10-K”). Our financial statements have been prepared in accordance with generally accepted accounting principles (“GAAP”) in the United States (“U.S.”).

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 Products Partners L.P. conducts 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 Texas limited liability company.

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 and Chairman of the Board of Enterprise GP; (ii) Dr. Ralph S. Cunningham, who is also a director of Enterprise GP; and (iii) Richard H. Bachmann, who is also a director of Enterprise GP. Each of the DD LLC Trustees also currently serves as one of the three managers of Dan Duncan LLC.

References to “EPCO” mean Enterprise Products Company, a Texas corporation, 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 also serves as Chairman of EPCO; (ii) Dr. Cunningham, who also serves as a Vice Chairman of EPCO; and (iii) Mr. Bachmann, who also serves as the President and Chief Executive Officer (“CEO”) of EPCO. Each of the EPCO Trustees is also a director of EPCO.

As generally used in the energy industry and in this quarterly report, the acronyms below have the following meanings:

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

Cautionary Statement Regarding Forward-Looking Information

This quarterly report on Form 10-Q contains various forward-looking statements and information that are based on our beliefs and those of our general partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as “anticipate,” “project,” “expect,” “plan,” “seek,” “goal,” “estimate,” “forecast,” “intend,” “could,” “should,” “would,” “will,” “believe,” “may,” “potential” and similar expressions and statements regarding our plans and objectives for future operations are intended to identify forward-looking statements. Although we and our general partner believe that our 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 “Risk Factors” within Part I, Item 1A included in our 2012 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 filing 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 New York Stock Exchange (“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 petrochemicals.

Our integrated midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the U.S., Canada and Gulf of Mexico with domestic consumers and international markets. Our midstream energy operations include: natural gas gathering, treating, processing, transportation and storage; NGL transportation, fractionation, storage, and import and export terminals (including LPG); crude oil gathering, transportation, storage and terminals; offshore production platforms; petrochemical and refined products transportation and services; and a marine transportation business that operates primarily on the U.S. inland and Intracoastal Waterway systems and in the Gulf of Mexico. Our assets include approximately 50,000 miles of onshore and offshore pipelines; 200 MMBbls of storage capacity for NGLs, petrochemicals, refined products and crude oil; and 14 Bcf of natural gas storage capacity. In addition, our asset portfolio includes 24 natural gas processing plants, 21 NGL and propylene fractionators, six offshore hub platforms located in the Gulf of Mexico, a butane isomerization complex, NGL import and export terminals, and octane enhancement and high-purity isobutylene production facilities.

We conduct substantially all of our business through EPO and are owned 100% by our limited partners from an economic perspective. Enterprise GP manages our partnership and owns a non-economic general partner interest in us. Like many publicly traded partnerships, we have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to an administrative services agreement or by other service providers.

We have five reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services; and (v) Petrochemical & Refined Products Services. For information regarding our business segments, see Note 11 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Significant Recent Developments

The following information highlights significant commercial and operational developments since January 1, 2013 through the date of this filing (August 8, 2013). For information regarding recent offerings of our equity and debt securities and the expansion of our bank credit facilities, see “Liquidity and Capital Resources” within this Part I, Item 2.

Formation of Joint Venture to Own Two New NGL Fractionators at Mont Belvieu Complex

In June 2013, we formed a joint venture, Enterprise EF78 LLC, with Western Gas Partners, LP (“Western Gas”), an affiliate of Anadarko Petroleum Corporation, involving two NGL fractionators that are under construction at our complex in Mont Belvieu, Texas (i.e., NGL fractionators seven and eight). We own 75% of the joint venture’s membership interests and consolidate the joint venture. Western Gas acquired a 25% noncontrolling interest in the joint venture for an initial contribution of \$90.2 million, which is reflected as a contribution from noncontrolling interests on our Unaudited Statements of Consolidated Cash Flows for the six months ended June 30, 2013. NGL fractionators seven and eight are expected to begin operations in the fourth quarter of 2013 and, as designed, have a combined fractionation capacity of approximately 170 MBPD of NGLs.

Plans to Develop Refined Products Export Facilities on Texas Gulf Coast

In May 2013, we announced the development of two refined products export facilities, one in Beaumont, Texas and another on the Houston Ship Channel, to meet growing demand for additional refined products export capability on the U.S. Gulf Coast. Export service at our Beaumont marine terminal is expected to begin during the first quarter of 2014 and initially accommodate Panamax class vessels, followed in mid-2014 by completion of our expanded marine terminal on the Houston Ship Channel, which is being designed to handle up to Aframax class vessels. Panamax and Aframax class vessels are both medium-sized tanker ships; however, Panamax vessels are designed to be able to transit the existing lock chambers of the Panama Canal. These new export facilities will complement our existing refined products pipelines, storage and terminal facilities in southeast Texas and enable us to provide customers with improved access to international markets.

Plans to Expand Crude Oil Storage and Distribution Infrastructure Serving Southeast Texas

Historically, Southeast Texas refineries have been primarily supplied by waterborne imports of crude oil. With the success of North America producers, crude oil from the Eagle Ford, Permian, Midcontinent, Bakken and Canada are flowing into Southeast Texas and displacing waterborne crude oil imports. As production from these regions continues to grow, we expect a significant increase in crude oil deliveries to the U.S. Gulf Coast market, which currently lacks sufficient storage capacity and has an inadequate distribution system for handling these varying grades of domestic crude oil.

In response, we announced plans in May 2013 to significantly expand our crude oil storage and distribution infrastructure serving the Southeast Texas refinery market. This planned expansion involves the construction of approximately 4.0 MMBbls of combined new crude oil storage capacity in the Houston, Texas area, including additional storage capacity at our Enterprise Crude Houston (“ECHO”) storage facility. Also, we plan to construct 55 miles of associated pipelines to directly connect ECHO with several major refineries in the Southeast Texas market. The expansion would be completed in phases with final completion expected in the fourth quarter of 2014.

Upon completion, we will be able to provide Southeast Texas refiners with an integrated system featuring supply diversification, significant storage capabilities and a high capacity distribution system that will be connected via pipeline to refineries having an aggregate capacity of approximately 3.6 MMBPD. In addition, ECHO, which is expected to have over 6.0 MMBbls of crude oil storage capacity following the expansion, will have access to our marine terminal at Morgan’s Point on the Houston Ship Channel.

Plans to Build Gulf Coast Ethane Pipeline

In March 2013, we announced the receipt of transportation commitments to support development of a new 270-mile pipeline system, the Aegis Pipeline, that will deliver ethane to petrochemical plants in the U.S. Gulf Coast region. The Aegis Pipeline will originate at our Mont Belvieu, Texas storage complex and have the capacity to transport purity ethane volumes to various petrochemical customers in Texas and Louisiana. The Aegis Pipeline is expected to begin commercial operations in 2014.

Operations Begin at Expanded LPG Export Facility

In March 2013, we completed an expansion project at our Houston Ship Channel LPG export terminal thereby increasing our capability to load propane, butane and isobutane (collectively, “LPG”) cargoes. This expansion project increased the terminal’s fully refrigerated export loading capacity for low-ethane propane from almost 4 MMBbls per month to approximately 7.5 MMBbls per month.

Oiltanking Partners, L.P. (“Oiltanking”) leases to us the site upon which our LPG export terminal facility is located. In March 2013, we executed an amended terminal service agreement with Oiltanking that provides us with additional operating flexibility, including an increase in the number of docks available to load LPG cargoes. The amended terminal service agreement extends to 2026. Access to these additional docks could support further expansions of the export facility. We are currently evaluating an additional expansion project that could increase our propane export capacity to approximately 10 MMBbls per month and begin service as soon as the beginning of 2015.

Results of Operations

Summarized Consolidated Income Statement Data

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
Revenues	\$ 11,149.3	\$ 9,789.8	\$ 22,532.4	\$ 21,042.3
Costs and expenses:				
Operating costs and expenses:				
Cost of sales	9,458.3	8,195.2	19,150.8	17,861.0
Other operating costs and expenses	586.4	572.9	1,090.4	1,116.8
Depreciation, amortization and accretion	289.7	261.3	566.5	515.9
Losses (gains) attributable to asset sales and insurance recoveries	5.7	(29.0)	(58.2)	(31.5)
Non-cash asset impairment charges	27.1	9.1	38.1	14.5
Total operating costs and expenses	10,367.2	9,009.5	20,787.6	19,476.7
General and administrative costs	45.5	42.5	95.0	88.8
Total costs and expenses	10,412.7	9,052.0	20,882.6	19,565.5
Equity in income of unconsolidated affiliates	37.6	11.3	82.1	21.2
Operating income	774.2	749.1	1,731.9	1,498.0
Interest expense	(200.2)	(186.6)	(396.1)	(373.1)
Other, net	(0.3)	13.2	(0.4)	71.9
Benefit from (provision for) income taxes	(20.4)	(8.5)	(26.8)	25.9
Net income	553.3	567.2	1,308.6	1,222.7
Net income attributable to noncontrolling interests	(0.8)	(0.9)	(2.6)	(5.1)
Net income attributable to limited partners	\$ 552.5	\$ 566.3	\$ 1,306.0	\$ 1,217.6

Consolidated Revenues by Business Segment

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
NGL Pipelines & Services:				
Sales of NGLs and related products	\$ 3,235.9	\$ 3,133.9	\$ 6,901.5	\$ 7,249.2
Midstream asset services	269.0	198.6	554.4	437.8
Total	3,504.9	3,332.5	7,455.9	7,687.0
Onshore Natural Gas Pipelines & Services:				
Sales of natural gas	723.9	510.8	1,363.4	1,083.4
Midstream services	233.6	209.6	471.8	470.6
Total	957.5	720.4	1,835.2	1,554.0
Onshore Crude Oil Pipelines & Services:				
Sales of crude oil	5,057.4	4,174.0	9,800.2	8,621.6
Midstream asset services	72.1	14.7	122.5	40.7
Total	5,129.5	4,188.7	9,922.7	8,662.3
Offshore Pipelines & Services:				
Sales of natural gas	0.1	--	0.2	0.1
Sales of crude oil	(0.1)	--	2.2	1.4
Midstream asset services	41.3	49.0	81.5	103.6
Total	41.3	49.0	83.9	105.1
Petrochemical & Refined Products Services:				
Sales of petrochemicals and refined products	1,334.2	1,316.8	2,881.4	2,668.0
Midstream asset services	181.9	182.4	353.3	365.9
Total	1,516.1	1,499.2	3,234.7	3,033.9
Total consolidated revenues	\$ 11,149.3	\$ 9,789.8	\$ 22,532.4	\$ 21,042.3

Selected Energy Commodity Price Data

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

	Natural Gas, \$/MMBtu	Ethane, \$/gallon	Propane, \$/gallon	Normal Butane, \$/gallon	Isobutane, \$/gallon	Natural Gasoline, \$/gallon	Polymer Grade Propylene, \$/pound	Refinery Grade Propylene, \$/pound	WTI Crude Oil, \$/barrel	LLS Crude Oil, \$/barrel
	(1)	(2)	(2)	(2)	(2)	(2)	(3)	(3)	(4)	(4)
2012 by quarter:										
1st Quarter	\$2.72	\$0.56	\$1.26	\$1.93	\$2.04	\$2.39	\$0.69	\$0.60	\$102.93	\$119.59
2nd Quarter	\$2.21	\$0.40	\$0.98	\$1.62	\$1.75	\$2.05	\$0.66	\$0.51	\$93.49	\$108.47
3rd Quarter	\$2.80	\$0.34	\$0.89	\$1.44	\$1.62	\$2.01	\$0.51	\$0.37	\$92.22	\$109.40
4th Quarter	\$3.41	\$0.28	\$0.88	\$1.64	\$1.82	\$2.15	\$0.56	\$0.48	\$88.18	\$109.43
2012 Averages	\$2.79	\$0.40	\$1.00	\$1.65	\$1.81	\$2.15	\$0.60	\$0.49	\$94.20	\$111.72
2013 by quarter:										
1st Quarter	\$3.34	\$0.26	\$0.86	\$1.58	\$1.65	\$2.23	\$0.75	\$0.65	\$94.37	\$113.93
2nd Quarter	\$4.10	\$0.27	\$0.91	\$1.24	\$1.27	\$2.04	\$0.63	\$0.53	\$94.22	\$104.63
2013 Averages	\$3.72	\$0.27	\$0.89	\$1.41	\$1.46	\$2.14	\$0.69	\$0.59	\$94.30	\$109.28

- (1) Natural gas prices are based on Henry-Hub Inside FERC commercial index prices as reported by Platts, which is a division of McGraw Hill Financial, Inc.
- (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 ("WTI") as measured on the New York Mercantile Exchange ("NYMEX") and for Louisiana Light Sweet ("LLS") as reported by Platts.

Period-to-period fluctuations in our consolidated revenues and cost of sales amounts are explained in large part by changes in energy commodity prices. Energy commodity prices fluctuate for a variety of reasons, including supply and demand imbalances and geopolitical tensions. The following is a discussion of period-to-period changes in key commodity prices affecting our results of operations:

- The weighted-average indicative market price for NGLs (based on prices for such products at Mont Belvieu, Texas, which is the primary industry hub for domestic NGL production) was \$0.95 per gallon during the second quarter of 2013 versus \$1.09 per gallon during the second quarter of 2012 – a 13% quarter-to-quarter decrease. The weighted-average indicative market price for NGLs for the first six months of 2013 was \$0.99 per gallon compared to \$1.22 per gallon during the first six months of 2012 – a 19% period-to-period decrease. Ethane accounts for the largest volume of NGLs extracted from the natural gas stream (approximately 40% of NGLs produced from natural gas processing and fractionation operations). As a result of producers allocating more of their capital budgets to developing NGL-rich natural gas shale plays and their success in extracting such resources, ethane production has increased more rapidly than the ethylene industry's current capability to consume the increase in supplies. This oversupply situation has contributed to a significant decrease in average ethane prices since the beginning of 2012.

We believe this ethane oversupply may generally persist until ethylene producers increase their capacity to consume additional ethane feedstock volumes through plant modifications, expansions and the completion of recently announced new ethylene plants. For example, CP Chemical announced in December 2011 that it expects to build a 1.5 million metric tons per year ethylene plant in Cedar Bayou, Texas by 2017. Likewise, Formosa Plastics announced in March 2012 that it expects to build an 800 thousand metric tons per year ethylene plant along the U.S. Gulf Coast by 2016/2017. Also, Dow Chemical announced in April 2012 that it expects to build a 1.5 million metric tons per year ethylene plant along the U.S. Gulf Coast by 2017. Collectively, these and other announced petrochemical plant construction and expansion projects are expected to consume between 600 MBPD and 750 MBPD of ethane supplies when completed. However, in the near term and in the absence of such major plant construction projects being completed, the current ethane oversupply situation may result in volatile ethane prices and prolonged periods of ethane rejection by producers and natural gas processors in an effort to balance supply and demand. This could lower the

value of our equity NGL production and reduce the volumes that would otherwise be handled by our NGL fractionators and pipelines.

- The market price of natural gas (as measured at the Henry Hub in Louisiana) averaged \$4.10 per MMBtu during the second quarter of 2013 versus \$2.21 per MMBtu during the second quarter of 2012 – an 86% quarter-to-quarter increase. The Henry Hub market price of natural gas for the first six months of 2013 averaged \$3.72 per MMBtu compared to \$2.47 per MMBtu during the first six months of 2012 – a 51% period-to-period increase. In general, the period-to-period increase in prices is due to higher demand for natural gas for power generation and as a heating fuel. Natural gas prices (Henry Hub) continue to fluctuate below their 2011 and 2010 averages of \$4.04 per MMBtu and \$4.39 per MMBtu, respectively.
- The market price of WTI crude oil (as measured on the NYMEX) averaged \$94.22 per barrel during the second quarter of 2013 compared to \$93.49 per barrel during the second quarter of 2012. The NYMEX market price of WTI crude oil for the first six months of 2013 averaged \$94.30 per barrel compared to \$98.21 per barrel during the first six months of 2012. As a result of our recent crude oil pipeline infrastructure improvements, we have greater access to U.S. Gulf Coast refiners. Typically, these refining customers purchase crude oil based on LLS prices, which are significantly higher than WTI prices. Although lower quarter-to-quarter, LLS prices averaged \$104.63 per barrel during the second quarter of 2013 compared to \$108.47 per barrel during the second quarter of 2012. LLS prices averaged \$109.28 per barrel during the first six months 2013 compared to \$114.03 per barrel during the first six months of 2012.

A decrease in our consolidated marketing revenues due to lower energy commodity sales prices may not generate a decrease in gross operating margin or cash available for distribution, since our consolidated cost of sales amounts would also be lower due to comparable decreases in the purchase prices of the underlying energy commodities. The same correlation would be true in the case of higher energy commodity sales prices and purchase costs.

We attempt to mitigate any commodity price exposure through our hedging activities as well as through converting keepwhole and similar contracts to fee-based arrangements. For information regarding our commodity hedging activities, see Note 4 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Consolidated Income Statement Highlights

The following information highlights significant changes in our comparative income statement amounts and the primary drivers of such changes:

Revenues for the second quarter of 2013 increased \$1.36 billion when compared to the second quarter of 2012. Revenues from the marketing of NGLs, crude oil and refined products increased a combined \$1.17 billion quarter-to-quarter primarily due to higher sales volumes. Revenues from the marketing of natural gas increased \$213.2 million primarily due to higher natural gas prices quarter-to-quarter. Revenues from the marketing of petrochemical products decreased \$167.0 million quarter-to-quarter primarily due to lower sales prices, which accounted for an \$85.8 million decrease, and lower sales volumes, which accounted for an \$81.2 million decrease. Revenues from midstream asset services increased \$143.6 million quarter-to-quarter primarily due to contributions from our recently constructed assets in the Eagle Ford Shale supply basin (e.g., our new Yoakum natural gas processing plant and Eagle Ford NGL and crude oil pipelines) and at our Mont Belvieu complex.

For the six months ended June 30, 2013, revenues increased \$1.49 billion when compared to the six months ended June 30, 2012. Revenues from the marketing of crude oil and refined products increased a combined \$1.42 billion period-to-period primarily due to higher sales volumes. Revenues from the marketing of natural gas increased \$280.1 million period-to-period primarily due to higher sales prices. Revenues from the marketing of NGLs decreased \$347.7 million period-to-period due to lower NGL sales prices, which accounted for a \$1.66 billion decrease, partially offset by higher sales volumes, which accounted for a \$1.31 billion increase. Revenues from the marketing of petrochemical products decreased \$30.9 million period-to-period primarily due to lower sales volumes. Revenues from midstream asset services increased \$164.9 million period-to-period primarily due to contributions from our recently constructed assets in the Eagle Ford Shale supply basin and at our Mont Belvieu complex.

Total operating costs and expenses for the second quarter of 2013 increased \$1.36 billion when compared to the second quarter of 2012 primarily due to a \$1.26 billion increase in our cost of sales amounts. The cost of sales associated with our marketing of NGLs, crude oil and refined products increased \$1.14 billion quarter-to-quarter primarily due to higher sales volumes. Cost of sales associated with the marketing of natural gas increased \$197.5 million quarter-to-quarter primarily due to higher natural gas prices. Cost of sales associated with our marketing of petrochemical products decreased \$78.8 million quarter-to-quarter primarily due to lower purchase prices. Other operating costs and expenses increased \$13.5 million quarter-to-quarter primarily due to the addition of operating costs of newly constructed assets.

For the six months ended June 30, 2013, total operating costs and expenses increased \$1.31 billion when compared to the same period in 2012 primarily due to a \$1.29 billion increase in cost of sales. The cost of sales associated with our marketing of crude oil and refined products increased \$1.22 billion period-to-period primarily due to higher sales volumes. Cost of sales associated with our marketing of natural gas increased \$213.3 million period-to-period primarily due to higher sales prices. Cost of sales associated with the marketing of NGLs decreased \$98.4 million period-to-period due to lower NGL sales prices, which accounted for a \$1.33 billion decrease, partially offset by higher sales volumes, which accounted for a \$1.23 billion increase. Cost of sales associated with our marketing of petrochemical products decreased \$45.7 million primarily due to lower sales volumes. Other operating costs and expenses decreased \$26.4 million period-to-period primarily due to the sale of assets, which accounted for a \$53.5 million decrease, partially offset by the addition of operating costs of newly constructed assets.

Depreciation, amortization and accretion in operating costs and expenses for the second quarter of 2013 increased \$28.4 million when compared to the second quarter of 2012 and \$50.6 million for the six months ended June 30, 2013 when compared to the same six-month period in 2012. These increases were primarily due to recently constructed assets being placed into service since the second quarter of 2012.

Losses attributable to asset sales and insurance recoveries in operating costs and expenses were \$5.7 million during the second quarter of 2013 compared to gains of \$29.0 million during the second quarter of 2012. The \$34.7 million quarter-to-quarter change is primarily due to \$27.7 million of gains related to nonrefundable insurance proceeds we received during the second quarter of 2012. These proceeds were attributable to property damage claims we filed in connection with the February 2011 NGL release and fire at the West Storage location of

our Mont Belvieu, Texas underground storage facility. We did not receive any such proceeds during the second quarter of 2013; however, we remain in negotiations with our insurance carriers for collection of the remaining West Storage claims, which are currently estimated at \$91.9 million. To the extent that additional nonrefundable cash insurance proceeds related to this incident are received, we expect to record gains equal to such proceeds.

We recorded gains attributable to asset sales and insurance recoveries of \$58.2 million for the six months ended June 30, 2013 compared to \$31.5 million for the six months ended June 30, 2012. In March 2013, we sold the Stratton Ridge-to-Mont Belvieu segment of the Seminole Pipeline, along with a related storage cavern, and recognized a \$52.5 million gain on the sale. In addition, we recognized \$8.8 million of gains attributable to the receipt of nonrefundable cash insurance proceeds related to our West Storage claims during the six months ended June 30, 2013 compared to \$27.7 million of such gains for the six months ended June 30, 2012.

We recorded \$27.1 million and \$9.1 million of non-cash asset impairment charges during the second quarter of 2013 and 2012, respectively. For the six months ended June 30, 2013, we recorded \$38.1 million of such charges compared to \$14.5 million for the same period in 2012. Our non-cash asset impairment charges during the six months ended June 30, 2013 are primarily related to the abandonment of certain crude oil pipeline segments in Texas and Oklahoma, certain refined products terminal and storage assets in southeast Texas and an NGL storage cavern in Arizona. For additional information regarding our asset impairment charges, see Note 4 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

General and administrative costs increased \$3.0 million for the second quarter of 2013 and \$6.2 million for the six months ended June 30, 2013 when compared to the same respective periods in 2012. These increases were primarily due to higher employee compensation expenses.

Equity income from our unconsolidated affiliates increased \$26.3 million for the second quarter of 2013 and \$60.9 million for the six months ended June 30, 2013 when compared to the same respective periods in 2012. These increases were primarily due to increased earnings from our investments in crude oil pipeline joint ventures.

Interest expense for the second quarter of 2013 increased \$13.6 million when compared to the second quarter of 2012. Likewise, interest expense for the six months ended June 30, 2013 increased \$23.0 million when compared to the same six-month period in 2012. These increases were primarily due to interest costs associated with assets placed into service since the second quarter of 2012 being recognized in earnings as opposed to being capitalized during construction. The \$13.6 million quarter-to-quarter increase in expense was largely due to assets being placed into service, which accounted for a \$23.7 million increase, partially offset by the effects of lower interest rates, which accounted for an \$11.0 million decrease. The \$23.0 million period-to-period increase in expense was also largely due to assets being placed into service, which resulted in a \$50.3 million increase, partially offset by the effects of lower interest rates, which accounted for a \$27.7 million decrease.

Our average debt principal balance for the second quarter of 2013 was \$17.15 billion compared to \$14.80 billion for the second quarter of 2012. With respect to the six months ended June 30, 2013, our average debt principal balance was \$16.90 billion compared to \$14.66 billion for the same period in 2012. In general, our debt principal balances have increased over time due to the financing of our capital spending program. For a discussion of our consolidated debt obligations and capital spending program, see "Liquidity and Capital Resources" within this Item 2. On a weighted-average basis, the interest rates we paid on our consolidated debt were 5.4% for the three and six months ended June 30, 2013 and 5.9% for the three and six months ended June 20, 2012.

Other income for the three and six months ended June 30, 2012 reflects \$15.5 million and \$68.8 million, respectively, of aggregate gains we recorded in connection with our sale of common units of Energy Transfer Equity, L.P. (together with its subsidiaries, "Energy Transfer Equity"). For additional information regarding our former investment in Energy Transfer Equity, see Note 7 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Provision for income taxes for the second quarter of 2013 increased \$11.9 million when compared to the second quarter of 2012 primarily due to Texas Margin Tax accruals. In June 2013, the State of Texas enacted certain changes to the Texas Margin Tax which lowered the tax rate and expanded the scope of depreciation deductions. As a result of these changes, current income tax expense decreased \$7.2 million and our deferred

income tax expense (related to book/tax depreciation timing differences) increased \$20.3 million, for a net \$13.1 million expense in the second quarter of 2013.

We recognized a net income tax expense of \$26.8 million for the first six months of 2013 compared to a net income tax benefit of \$25.9 million for the same period in 2012. The \$52.7 million period-to-period change is primarily due to (i) a \$46.5 million benefit recorded in the first quarter of 2012 related to the conversion of certain of our subsidiaries to limited liability companies and (ii) the \$13.1 million of expense recorded in June 2013 related to the Texas Margin Tax (as discussed above).

Business Segment Highlights

Total segment gross operating margin was \$1.14 billion for the second quarter of 2013 compared to \$1.03 billion for the second quarter of 2012. For the six months ended June 30, 2013 and 2012, total segment gross operating margin was \$2.37 billion and \$2.09 billion, respectively.

The following information highlights significant changes in our comparative segment results (i.e., gross operating margin amounts) and the primary drivers of such changes. The selected volume statistics presented in the tabular information for each segment 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 purchased assets from the date of acquisition.

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. For information regarding this financial metric, see “Other Items – Use of Non-GAAP Financial Measures” within this Part I, Item 2.

All activities included in our former sixth reportable business segment, Other Investments, ceased on January 18, 2012, which was the date we discontinued using the equity method to account for our previously held investment in Energy Transfer Equity. Our equity earnings from this investment were \$2.4 million for the first quarter of 2012.

NGL Pipelines & Services. The following table presents segment gross operating margin and selected volumetric data for the NGL Pipelines & Services segment for the periods indicated (dollars in millions, volumes as noted):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
Segment gross operating margin:				
Natural gas processing and related NGL marketing activities	\$ 263.9	\$ 338.8	\$ 533.5	\$ 760.5
NGL pipelines and related storage	187.8	157.8	420.0	326.2
NGL fractionation	93.2	69.2	183.9	134.0
Total	<u>\$ 544.9</u>	<u>\$ 565.8</u>	<u>\$ 1,137.4</u>	<u>\$ 1,220.7</u>
Selected volumetric data:				
Equity NGL production (MBPD) (1)	118	96	120	104
Fee-based natural gas processing (MMcf/d) (2)	4,581	4,232	4,553	4,183
NGL transportation volumes (MBPD)	2,744	2,440	2,641	2,409
NGL fractionation volumes (MBPD)	678	654	693	638

(1) Represents the NGL volumes we earn and take title to in connection with our processing activities.

(2) Volumes reported correspond to the revenue streams earned by our gas plants. The period-to-period increases in fee-based processing volumes are primarily due to (i) the start-up of our Yoakum gas plant in May 2012 and (ii) changes in processing agreements whereby producers are electing to process more of their natural gas on a fee basis in order to retain NGLs extracted from their natural gas streams, which, in turn, also lowers our equity NGL production from plants subject to such arrangements.

Natural gas processing and related NGL marketing activities

Gross operating margin from our natural gas processing and related NGL marketing activities decreased \$74.9 million in the second quarter of 2013 when compared to the second quarter of 2012 primarily due to lower results from our Rocky Mountain gas plants. Gross operating margin from our Meeker natural gas processing plant in Colorado decreased \$55.4 million quarter-to-quarter primarily due to lower processing margins in the second quarter of 2013. In general, natural gas processing margins are lower in 2013 compared to 2012 due to lower overall NGL prices, primarily ethane and propane, and higher natural gas prices in each respective period. Gross operating margin from our Pioneer natural gas processing plant in Wyoming decreased \$27.9 million quarter-to-quarter primarily due to the effects of ethane rejection and overall production declines, both of which lowered equity NGL production during 2013 when compared to 2012. In general, producers utilizing our Pioneer facility have curtailed their drilling programs in the Jonah and Pinedale production fields in response to low prices.

Gross operating margin from our South Texas natural gas processing plants increased \$8.7 million quarter-to-quarter primarily due to higher volumes, which accounted for a \$15.7 million increase, higher processing fees, which resulted in a \$5.4 million increase, partially offset by lower processing margins, which accounted for a \$13.4 million decrease. These gas plants continue to benefit from NGL-rich natural gas production from the Eagle Ford Shale and the start-up of our Yoakum processing plant. The first phase (or “train”) of our new cryogenic natural gas processing plant at Yoakum, Texas commenced operations in May 2012. We placed the second and third trains in-service at the Yoakum plant in August 2012 and March 2013, respectively. Gross operating margin from our remaining natural gas processing plants decreased a combined \$14.5 million quarter-to-quarter primarily due to lower processing margins in the second quarter of 2013.

Gross operating margin from our NGL marketing activities increased \$14.2 million quarter-to-quarter primarily due to higher sales volumes, which accounted for a \$28.9 million increase, partially offset by lower sales margins, which accounted for a \$14.8 million quarter-to-quarter decrease.

Gross operating margin from these businesses decreased \$227.0 million in the six months ended June 30, 2013 when compared to the same period in 2012. Gross operating margin from our Meeker and Pioneer natural gas processing plants decreased \$108.9 million and \$74.2 million period-to-period, respectively, attributable to the same reasons described above for the quarter-to-quarter changes. Gross operating margin from our South Texas natural gas processing plants increased \$14.7 million period-to-period primarily due to higher volumes, which accounted for a \$33.2 million increase, higher processing fees, which resulted in a \$13.7 million increase, partially offset by lower processing margins, which accounted for a \$32.6 million decrease. Gross operating margin from our remaining natural gas processing plants decreased a combined \$34.7 million period-to-period primarily due to lower processing margins in the 2013 period.

Gross operating margin from our NGL marketing activities increased \$9.8 million period-to-period primarily due to higher sales volumes, which accounted for a \$61.4 million period-to-period increase, partially offset by lower sales margins, which accounted for a \$50.9 million decrease.

Gross operating margin for the first six months of 2012 included a \$20.0 million gain related to proceeds received in a vendor settlement and a \$13.7 million gain attributable to changes in a provision for certain plant capacity obligations.

NGL pipelines and related storage

Gross operating margin from our NGL pipelines and related storage assets for the second quarter of 2013 increased \$30.0 million when compared to the second quarter of 2012 largely due to strong results from our South Texas and Houston region assets. Gross operating margin from our South Texas NGL Pipeline System increased \$20.9 million quarter-to-quarter primarily due to a 125 MBPD increase in transportation volumes associated with Eagle Ford Shale production. Gross operating margin from our Houston Ship Channel LPG export terminal and related Channel Pipeline increased a combined \$12.0 million quarter-to-quarter primarily to due increased volumes. Loading volumes at our LPG export terminal increased 106 MBPD quarter-to-quarter and volumes on the related Channel Pipeline increased 96 MBPD quarter-to-quarter.

Gross operating margin from our Mid-America Pipeline System, Seminole Pipeline and related NGL terminals decreased \$0.4 million quarter-to-quarter primarily due to (i) a 50 MBPD decrease in transportation volumes, which accounted for \$6.2 million of the decrease, (ii) slightly higher operating costs of \$1.6 million quarter-to-quarter, partially offset by (iii) higher tariffs and other fees of \$7.4 million. Volumes on our Mid-America and Seminole pipelines decreased during 2013 primarily due to lower NGL production from Rocky Mountain gas plants caused by ethane rejection.

With respect to the six months ended June 30, 2013, gross operating margin from NGL pipelines and related storage assets increased \$93.8 million when compared to the same period in 2012 largely due to strong results from our South Texas and Houston region assets and the Dixie Pipeline. Gross operating margin from our South Texas NGL Pipeline System increased \$42.9 million period-to-period primarily due to a 102 MBPD increase in transportation volumes associated with Eagle Ford Shale production. Gross operating margin from our Houston Ship Channel LPG export terminal and related Channel Pipeline increased a combined \$15.8 million period-to-period primarily due to increased volumes. Loading volumes at our LPG export terminal increased 73 MBPD period-to-period and volumes on the related Channel Pipeline increased 76 MBPD period-to-period. Gross operating margin from our Dixie Pipeline and related NGL terminals increased \$11.1 million period-to-period primarily due to a 29 MBPD increase in transportation volumes, which accounted for \$7.5 million of the increase, and higher transportation fees, which accounted for \$3.1 million of the increase. Transportation volumes on the Dixie Pipeline were negatively impacted during 2012 due to downtime associated with various pipeline integrity projects and warmer than normal winter weather.

Gross operating margin from our Lou-Tex NGL and Panola Pipelines increased a combined \$9.4 million period-to-period primarily due to higher transportation volumes of 21 MBPD period-to-period. Lastly, gross operating margin from our Mid-America Pipeline System, Seminole Pipeline and related NGL terminals increased a combined \$4.6 million period-to-period. A \$23.6 million increase in revenues associated with higher system-wide tariffs and other fees, combined with an \$8.7 million decrease in operating costs primarily due to pipeline gains during the 2013 period, was partially offset by a \$27.7 million decrease in gross operating margin attributable to a 105 MBPD decrease in transportation volumes primarily due to lower NGL production from Rocky Mountain gas plants caused by ethane rejection.

NGL fractionation

Gross operating margin from NGL fractionation for the second quarter of 2013 increased \$24.0 million when compared to the second quarter of 2012 primarily due to higher fractionation fees and volumes at our Mont Belvieu complex. Our Mont Belvieu NGL fractionators continue to benefit from increased NGL production volumes transported from the Eagle Ford Shale.

Gross operating margin from our Mont Belvieu NGL fractionators increased \$19.3 million quarter-to-quarter primarily due to (i) higher average fractionation fees, which accounted for \$17.1 million of the increase, (ii) an increase in fractionation volumes of 57 MBPD (net to our interest), which accounted for an additional \$10.3 million of the increase, partially offset by (iii) a \$12.9 million increase in operating costs partially due to our sixth NGL fractionator, which commenced operations in December 2012. With respect to fractionation volumes at our Mont Belvieu complex for the second quarter of 2013, a 94 MBPD increase in processing volumes attributable to operations at our sixth NGL fractionator was partially offset by downtime at certain of our other Mont Belvieu NGL fractionators in connection with an expansion project.

Gross operating margin at our Shoup and Almeda NGL fractionators decreased \$2.3 million quarter-to-quarter primarily due to a 19 MBPD decrease in volumes. The decrease in volumes at Shoup and Almeda is attributable to more natural gas being processed at our Yoakum facility, with the resulting mixed NGL stream being transported to our Mont Belvieu complex for fractionation. Gross operating margin at our Hobbs and Norco NGL fractionators increased a combined \$6.1 million primarily due to higher fractionation fees during the second quarter of 2013.

With respect to the six months ended June 30, 2013, gross operating margin from NGL fractionation increased \$49.9 million when compared to the same period in 2012. Gross operating margin from our Mont Belvieu NGL fractionators increased \$47.6 million period-to-period primarily due to (i) an increase in fractionation volumes

of 83 MBPD, which accounted for \$32.7 million of the increase, (ii) higher average fractionation fees, which accounted for \$30.9 million of the increase, partially offset by (iii) a \$20.7 million increase in operating costs, including those attributable to our sixth NGL fractionator. Gross operating margin from our Shoup and Alameda NGL fractionators decreased \$5.8 million period-to-period primarily due to a 17 MBPD decrease in volumes. Gross operating margin at our Hobbs and Norco NGL fractionator increased a combined \$5.9 million period-to-period primarily due to higher fractionation fees.

Onshore Natural Gas Pipelines & Services. The following table presents segment gross operating margin and selected volumetric data for the Onshore Natural Gas Pipelines & Services segment for the periods indicated (dollars in millions, volumes as noted):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
Segment gross operating margin	\$ 197.7	\$ 175.8	\$ 388.5	\$ 382.0
Selected volumetric data:				
Natural gas transportation volumes (BBtus/d)	13,307	13,793	13,189	13,436

Gross operating margin from onshore natural gas pipelines and services for the second quarter of 2013 increased \$21.9 million when compared to the second quarter of 2012 primarily due to contributions from the Texas Intrastate System. Gross operating margin from our Texas Intrastate System increased \$21.8 million quarter-to-quarter primarily due to higher firm capacity reservation revenues. Increased natural gas production volumes from the Eagle Ford Shale supply basin, in large part a by-product of increased NGL and crude oil production, continues to support strong demand for our natural gas transportation services on the Texas Intrastate System. Natural gas transportation volumes for the Texas Intrastate System increased 311 BBtus/d quarter-to-quarter.

Gross operating margin from our San Juan Gathering System increased \$4.5 million quarter-to-quarter primarily due to higher gathering fees, which are indexed to natural gas prices and accounted for \$6.7 million of the increase, partially offset by the impact of lower gathering volumes, which accounted for a \$2.2 million decrease in results. Lastly, gross operating margin from the Jonah, Piceance Basin and Haynesville Gathering Systems decreased a combined \$4.7 million quarter-to-quarter primarily due to lower gathering volumes. Producers served by these four gathering systems have curtailed their drilling programs in response to the continued low price of natural gas and NGLs. Collectively, natural gas transportation volumes for these gathering systems decreased 779 BBtus/d quarter-to-quarter.

With respect to the six months ended June 30, 2013, gross operating margin from onshore natural gas pipelines and services increased \$6.5 million. Gross operating margin from our Texas Intrastate System increased \$29.8 million period-to-period primarily due to higher firm capacity reservation revenues. Gross operating margin from our Jonah, Piceance Basin and Haynesville Gathering Systems decreased a combined \$15.1 million period-to-period primarily due to lower gathering volumes. Gross operating margin from our Acadian Gas System decreased \$5.9 million period-to-period primarily due to higher operating expenses during the 2013 period. Lastly, gross operating margin from our San Juan Gathering System decreased \$1.6 million period-to-period primarily due to (i) lower gathering volumes, which accounted for a \$6.7 million decrease, (ii) lower treating, compression and condensate revenues, which accounted for a \$4.3 million decrease, partially offset by (iii) higher gathering fees, which are indexed to natural gas prices and accounted for a \$9.4 million increase. Natural gas transportation volumes for the six months ended June 30, 2013 decreased 247 BBtus/d when compared to the first six months of 2012 primarily due to a combined 730 BBtus/d decrease in gathering volumes on our Jonah, Piceance Basin, Haynesville and San Juan gathering systems partially offset by increased volumes of 351 BBtus/d on our Texas Intrastate System and 129 BBtus/d on our Acadian Gas System.

Onshore Crude Oil Pipelines & Services. The following table presents segment gross operating margin and selected volumetric data for the Onshore Crude Oil Pipelines & Services segment for the periods indicated (dollars in millions, volumes as noted):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
Segment gross operating margin	\$ 197.2	\$ 95.8	\$ 433.6	\$ 135.1
Selected volumetric data:				
Crude oil transportation volumes (MBPD)	1,145	725	1,073	716

Gross operating margin from our onshore crude oil pipelines and services business for the second quarter of 2013 increased \$101.4 million when compared to the second quarter of 2012 primarily due to higher volumes on our crude oil pipeline systems. Gross operating margin from our South Texas Crude Oil Pipeline System increased \$58.7 million quarter-to-quarter primarily due to higher transportation volumes attributable to the Eagle Ford Expansion pipeline, which commenced operations in June 2012 and transported 164 MBPD during the second quarter of 2013. Equity earnings from our investments in crude oil pipeline joint ventures (Seaway and Eagle Ford) increased \$26.5 million quarter-to-quarter primarily due to a 200 MBPD increase in transportation volumes (net to our interest) attributable to the completion of expansion capital projects since the first quarter of 2012. Gross operating margin from our crude oil marketing and related activities increased \$11.8 million quarter-to-quarter primarily due to higher sales volumes, which accounted for \$7.6 million of the increase, and higher sales margins, which accounted for \$3.8 million of the increase. Our crude oil marketing activities continue to benefit from increased crude oil production volumes from the Eagle Ford Shale, Permian Basin and Rocky Mountain regions.

With respect to the six months ended June 30, 2013, gross operating margin from onshore crude oil pipelines and services increased \$298.5 million period-to-period primarily due to improved results from our crude oil marketing activities and higher volumes on our crude oil pipeline systems. Gross operating margin from our crude oil marketing and related activities increased \$124.1 million period-to-period primarily due to higher sales margins. Gross operating margin from our South Texas Crude Oil Pipeline System increased \$104.6 million period-to-period primarily due to volumes attributable to the Eagle Ford Expansion pipeline, which transported 157 MBPD during the six months ended June 30, 2013. Equity earnings from our investments in crude oil pipeline joint ventures increased \$62.6 million primarily due to a 164 MBPD increase in transportation volumes (net to our interest).

Offshore Pipelines & Services. The following table presents segment gross operating margin and selected volumetric data for the Offshore Pipelines & Services segment for the periods indicated (dollars in millions, volumes as noted):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
Segment gross operating margin	\$ 39.7	\$ 38.3	\$ 80.2	\$ 90.4
Selected volumetric data:				
Natural gas transportation volumes (BBtus/d)	720	907	726	934
Crude oil transportation volumes (MBPD)	311	285	303	287
Platform natural gas processing (MMcf/d)	224	326	234	341
Platform crude oil processing (MBPD)	14	18	14	19

Gross operating margin from our offshore pipelines and services business increased \$1.4 million for the second quarter of 2013 when compared to the second quarter of 2012. The primary reasons for this quarter-to-quarter increase were improved results from our equity investment in the Cameron Highway Oil Pipeline (“Cameron Highway”) and lower insurance costs, partially offset by a decrease in gross operating margin amounts from our Independence Hub platform and related Independence Trail pipeline. Equity earnings from Cameron Highway increased \$3.7 million quarter-to-quarter primarily due to a 42 MBPD increase (net to our interest) in transportation volumes. Gross operating margin for this segment also benefited from a \$3.7 million quarter-to-quarter decrease in insurance costs. Due to the high cost of windstorm coverage for our offshore Gulf of Mexico assets, we elected to self-insure these assets during the annual policy period extending from June 2012 to June 2013. We made the same

election for the current annual policy period, which extends from June 2013 to June 2014. For a discussion of insurance-related matters, see “Other Items – Insurance Matters” within this Part I, Item 2.

The favorable quarter-to-quarter variances attributable to improved earnings from Cameron Highway and lower insurance costs were partially offset by a combined \$4.3 million decrease in gross operating margin from our Independence Hub platform and Independence Trail pipeline primarily due to lower platform processing and pipeline throughput volumes. Natural gas processing volumes on the Independence Hub platform decreased 80 MMcf/d quarter-to-quarter (net to our interest) and natural gas transportation volumes on the Independence Trail pipeline decreased 84 BBtus/d quarter-to-quarter.

With respect to the six months ended June 30, 2013, gross operating margin from offshore pipelines and services decreased \$10.2 million period-to-period. The primary reasons for this period-to-period decrease were lower fees and volumes impacting our Independence Hub platform and Trail pipeline, partially offset by improved results from Cameron Highway and lower insurance costs. Collectively, gross operating margin from our Independence Hub platform and Trail pipeline decreased \$18.4 million period-to-period primarily due to the expiration of contractual demand fees during the first quarter of 2012, which accounted for \$9.7 million of the decrease between the two six-month periods, and lower platform processing and pipeline throughput volumes during the 2013 period, which accounted for \$8.7 million of the decrease in gross operating margin. Natural gas processing volumes on the Independence Hub platform decreased 84 MMcf/d period-to-period (net to our interest) and natural gas transportation volumes on the Independence Trail pipeline decreased 84 BBtus/d period-to-period. Equity earnings from Cameron Highway increased \$3.8 million period-to-period primarily due to a 22 MBPD increase (net to our interest) in transportation volumes. Gross operating margin for this segment also benefited from a \$7.5 million period-to-period decrease in insurance costs.

Petrochemical & Refined Products Services. The following table presents segment gross operating margin and selected volumetric data for the Petrochemical & Refined Products Services segment for the periods indicated (dollars in millions, volumes as noted):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
Segment gross operating margin:				
Propylene fractionation and related activities	\$ 26.1	\$ 42.8	\$ 61.1	\$ 103.9
Butane isomerization	27.4	25.1	50.8	45.7
Octane enhancement and related plant operations	43.0	50.7	81.3	37.6
Refined products pipelines and related activities	48.7	18.1	105.3	30.2
Marine transportation and other	17.5	20.6	35.1	37.7
Total	\$ 162.7	\$ 157.3	\$ 333.6	\$ 255.1
Selected volumetric data:				
Propylene fractionation volumes (MBPD)	71	73	70	73
Butane isomerization volumes (MBPD)	97	100	91	91
Octane additive and related plant production volumes (MBPD)	20	22	18	14
Transportation volumes, primarily refined products and petrochemicals (MBPD)	688	625	684	659

Propylene fractionation and related activities

Gross operating margin from our propylene fractionation and related petrochemical marketing activities decreased \$16.7 million for the second quarter of 2013 when compared to the second quarter of 2012 primarily due to lower propylene sales margins during the second quarter of 2013. With respect to the six months ended June 30, 2013, gross operating margin decreased \$42.8 million when compared to the same period in 2012 also primarily due to lower propylene sales margins during the first six months of 2013.

Butane isomerization

Gross operating margin from butane isomerization for the second quarter of 2013 increased \$2.3 million when compared to the second quarter of 2012. Likewise, gross operating margin for the first six months of 2013

increased \$5.1 million when compared to the same period in 2012. Both the quarter-to-quarter and year-to-date increases in gross operating margin are primarily due to the addition of a new deisobutanizer facility at our Mont Belvieu complex in March 2013.

Octane enhancement and related plant operations

Gross operating margin from octane enhancement and related high purity isobutylene plant operations for the second quarter of 2013 decreased a combined \$7.7 million when compared to the second quarter of 2012 primarily due to higher operating expenses during the second quarter of 2013. With respect to the six months ended June 30, 2013, gross operating margin for these facilities increased \$43.7 million when compared to the same period in 2012. Gross operating margin from our octane enhancement facility for the first six months of 2013 increased \$44.7 million primarily due to higher motor gasoline additive sales margins, which accounted for \$28.9 million of the increase, and higher sales volumes, which accounted for \$21.3 million of the increase, partially offset by higher operating expenses of \$5.5 million. Our octane enhancement facility experienced several periods of downtime for maintenance during the six months ended June 30, 2012, which negatively impacted the facility's operating results for the prior year-to-date period.

Refined products pipelines and related activities

Gross operating margin from refined products pipelines and related activities for the second quarter of 2013 increased \$30.6 million when compared to the second quarter of 2012 primarily due to improved results from our TE Products Pipeline. Gross operating margin from this pipeline system increased \$33.4 million quarter-to-quarter primarily due to higher transportation fees, which accounted for a \$36.3 million increase, partially offset by a \$5.5 million decrease in gross operating margin attributable to lower interstate transportation volumes. The higher transportation fees quarter-to-quarter include a \$24.3 million benefit recognized in connection with the settlement of a rate case with certain shippers during the second quarter of 2013. The rate case covered certain interstate transportation volumes extending from the fourth quarter of 2012 to the second quarter of 2013. Overall, transportation volumes for the TE Products Pipeline increased 73 MBPD quarter-to-quarter due to higher intrastate shipments of petrochemicals and refined products in southeast Texas, which accounted for a combined 110 MBPD increase, partially offset by lower interstate transportation volumes for refined products and NGLs of 37 MBPD.

With respect to the six months ended June 30, 2013, gross operating margin from our refined products pipelines and related activities increased \$75.1 million when compared to the same period in 2012 primarily due to improved results from our TE Products Pipeline and refined products terminals and related marketing activities. Gross operating margin from our TE Products Pipeline increased \$44.1 million period-to-period primarily due to higher transportation fees, which accounted for \$39.2 million of the increase (including the impact of the rate case settlement discussed previously). Overall, transportation volumes for the TE Products Pipeline increased 31 MBPD period-to-period due to (i) higher intrastate shipments of petrochemicals and refined products in southeast Texas, which accounted for a 56 MBPD increase, (ii) higher interstate NGL transportation volumes of 9 MBPD, partially offset by (iii) lower interstate refined products transportation volumes of 34 MBPD. Gross operating margin from our refined products terminals increased \$23.3 million period-to-period primarily due to a \$16.6 million benefit attributable to reductions in a provision for future pipeline capacity obligations recorded in the first quarter of 2013.

Liquidity and Capital Resources

At June 30, 2013, we had \$4.46 billion of consolidated liquidity, which is defined as unrestricted cash on hand plus borrowing capacity available under EPO's bank facilities. Unrestricted cash on hand at June 30, 2013 was \$45.3 million. See "Consolidated Debt – 364-Day Credit Agreement" below for information regarding a new \$1.0 billion bank facility we entered into in June 2013. Based on current market conditions, we believe we will have sufficient liquidity, cash flow from operations and access to capital markets to fund our capital expenditures and working capital needs.

We expect to issue additional equity and debt securities to assist us in meeting our future liquidity requirements, including those related to capital spending. In June 2013, we filed with the SEC a new universal shelf registration statement (the "2013 Shelf") that replaced our prior universal shelf registration statement filed with the SEC in July 2010 (the "2010 Shelf"). The 2013 Shelf allows (and the prior 2010 Shelf allowed) Enterprise Products

Partners L.P. and EPO (each on a standalone basis) to issue an unlimited amount of equity and debt securities, respectively.

Consolidated Debt

We had \$16.97 billion of principal amounts outstanding under consolidated debt agreements at June 30, 2013. The following table presents contractually scheduled maturities of our consolidated debt obligations outstanding at June 30, 2013 for the next five years, and in total thereafter (dollars in millions):

	Scheduled Maturities of Debt						
	Total	Remainder of 2013	2014	2015	2016	2017	After 2017
Commercial Paper Notes	\$ 40.0	\$ 40.0	\$ --	\$ --	\$ --	\$ --	\$ --
Multi-Year Revolving Credit Facility	45.0	--	--	--	--	--	45.0
Senior Notes	15,350.0	--	1,150.0	1,300.0	750.0	800.0	11,350.0
Junior Subordinated Notes	1,532.7	--	--	--	--	--	1,532.7
Total	\$ 16,967.7	\$ 40.0	\$ 1,150.0	\$ 1,300.0	\$ 750.0	\$ 800.0	\$ 12,927.7

At June 30, 2013, our current maturities of debt totaled \$540.0 million. We expect to refinance the current maturities of our debt obligations at or prior to their maturity.

2013 Senior Notes Transactions. In March 2013, EPO issued \$1.25 billion principal amount of 3.35% senior notes due March 2023 (“Senior Notes HH”) and \$1.0 billion principal amount of 4.85% senior notes due March 2044 (“Senior Notes II”). Senior Notes HH were issued at 99.908% of their principal amount and Senior Notes II were issued at 99.619% of their principal amount. Net proceeds from the issuance of Senior Notes HH and II were used to repay debt, including (i) amounts outstanding under EPO’s \$3.5 Billion Multi-Year Revolving Credit Facility and EPO’s commercial paper program (which we used to repay \$550.0 million principal amount of senior notes that matured in February 2013) and (ii) \$650.0 million principal amount of senior notes that matured in April 2013, and for general company purposes.

Enterprise Products Partners L.P. has unconditionally guaranteed Senior Notes HH and II on an unsecured and unsubordinated basis. These senior notes rank equal with EPO’s existing and future unsecured and unsubordinated indebtedness and are senior to any existing and future subordinated indebtedness of EPO. These senior notes 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.

364-Day Credit Agreement. In June 2013, EPO entered into a 364-Day Revolving Credit Agreement with a group of lenders (the “364-Day Credit Agreement”). Under the terms of the 364-Day Credit Agreement, EPO may borrow up to \$1.0 billion at a variable interest rate for a term of 364 days, subject to the terms and conditions set forth therein. Borrowings under this credit agreement provide us with an additional source of liquidity to fund our capital spending program.

EPO’s obligations under the 364-Day Credit Agreement are not secured by any collateral; however, they are guaranteed by Enterprise Products Partners L.P. Amounts borrowed under the 364-Day Credit Agreement mature on June 18, 2014, although EPO may, between 15 and 60 days prior to the maturity date, elect to have the entire principal balance then outstanding continued as non-revolving term loans for a period of one additional year, payable on June 18, 2015.

The 364-Day Credit Agreement contains customary representations, warranties, covenants (affirmative and negative) and events of default, the occurrence of which would permit the lenders to accelerate the maturity date of amounts borrowed under the 364-Day Credit Agreement. The 364-Day Credit Agreement also restricts EPO’s ability to pay cash distributions to its parent, Enterprise Products Partners L.P., if a default or an event of default (as defined in the 364-Day Credit Agreement) has occurred and is continuing at the time such distribution is scheduled to be paid.

First Amendment to \$3.5 Billion Multi-Year Revolving Credit Facility. In June 2013, EPO amended the terms of its \$3.5 Billion Multi-Year Revolving Credit Facility to, among other things, extend the maturity date of commitments under the agreement from September 2016 to June 2018 and lower the applicable margin on borrowings.

See Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report for additional information regarding our consolidated debt.

Issuance of Common Units

The following table summarizes the issuance of Enterprise common units during the six months ended June 30, 2013 in connection with an underwritten equity offering, the at-the-market program, its quarterly distribution reinvestment plan (“DRIP”) and employee unit purchase plan (“EUPP”) (dollars in millions, number of units issued as shown):

	Number of Common Units Issued	Net Proceeds
Common units issued in connection with underwritten offering	9,200,000	\$ 486.6
Common units issued in connection with the at-the-market program	3,766,557	226.5
Common units issued in connection with the DRIP and EUPP	2,440,784	134.6
Total	<u>15,407,341</u>	<u>\$ 847.7</u>

In February 2013, we issued 9,200,000 common units to the public (including an over-allotment amount of 1,200,000 common units) at an offering price of \$54.56 per unit. This underwritten offering generated net cash proceeds of \$486.6 million, which were used to temporarily reduce amounts outstanding under EPO’s \$3.5 Billion Multi-Year Revolving Credit Facility and commercial paper program and for general company purposes.

We have a registration statement on file with the SEC covering the issuance of up to \$1.0 billion of our common units in amounts, at prices and on terms to be determined by market conditions and other factors at the time of such offerings. Pursuant to this “at-the-market” program, we may sell common units under an equity distribution agreement between Enterprise Products Partners L.P. and certain broker-dealers from time-to-time by means of ordinary brokers’ transactions through the NYSE at market prices, in block transactions or as otherwise agreed to with the broker-dealer parties to the agreement. During the six months ended June 30, 2013, we sold 3,766,557 common units under the program for aggregate gross proceeds of \$228.5 million. After taking into account applicable costs, these transactions result in net proceeds of \$226.5 million, of which \$214.2 million was received as of June 30, 2013. After taking into account the aggregate sale price of common units sold under this program through June 30, 2013, we have the capacity to issue additional common units under this program up to an aggregate sale price of \$566.1 million.

We also have registration statements on file with the SEC collectively authorizing the issuance of up to 70,000,000 of our common units in connection with our DRIP. The DRIP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of our common units they own by reinvesting the quarterly cash distributions they would otherwise receive from us into the purchase of additional new common units. We issued 2,359,089 common units under our DRIP during the six months ended June 30, 2013, which generated net proceeds of \$129.8 million. After taking into account the number of common units issued under the DRIP through June 30, 2013, we may issue an additional 21,134,203 common units under this plan.

In January 2013, affiliates of privately held EPCO, which own our general partner and approximately 37.0% of our limited partner interests at June 30, 2013, expressed their willingness to purchase at least \$100 million of our common units during 2013 through our DRIP. During the six months ended June 30, 2013, these EPCO affiliates reinvested \$50.0 million, resulting in the issuance of 908,217 common units under our DRIP (this amount being a component of the 2,359,089 common units issued in total under the DRIP during the first six months of 2013). In August 2013, these affiliates reinvested an additional \$25.0 million under the DRIP.

In addition to the DRIP, we have a registration statement on file with the SEC authorizing the issuance of up to 440,879 of our common units in connection with an employee unit purchase plan (or “EUPP”). We issued 81,695 common units under our EUPP during the six months ended June 30, 2013, which generated net proceeds of \$4.8 million. After taking into account the number of common units issued under the EUPP through June 30, 2013, we may issue an additional 214,341 common units under this plan.

The net cash proceeds we received from the issuance of common units during the six months ended June 30, 2013 were used to temporarily reduce amounts outstanding under EPO’s Multi-Year Revolving Credit Facility and commercial paper program and for general company purposes. For additional information regarding our registration statements, see Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Credit Ratings

As of August 8, 2013, the investment-grade credit ratings of EPO’s long-term senior unsecured debt securities were BBB+ from Standard and Poor’s and Baa1 from Moody’s. In addition, the credit ratings of EPO’s short-term senior unsecured debt securities were A-2 from Standard and Poor’s and P-2 from Moody’s. Fitch Ratings issued non-solicited ratings of BBB and F-2 for EPO’s long-term senior unsecured debt securities and short-term senior unsecured debt securities, respectively.

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.

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 indicated (dollars in millions). For additional information regarding our cash flow amounts, see the Unaudited Condensed Statements of Consolidated Cash Flows included under Part I, Item 1 of this quarterly report.

	For the Six Months Ended June 30,	
	2013	2012
Net cash flows provided by operating activities	\$ 1,530.9	\$ 1,338.3
Cash used in investing activities	1,802.6	749.8
Cash provided by (used in) financing activities	300.9	(593.8)

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, transport or store are principally used as fuel for residential, agricultural and commercial heating; as feedstocks in petrochemical manufacturing; by crude oil refineries; 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 Part I, Item 1A of our 2012 Form 10-K.

The following information highlights significant period-to-period fluctuations in our consolidated cash flow amounts:

Comparison of Six Months Ended June 30, 2013 with Six Months Ended June 30, 2012

Operating Activities. Cash provided by operating activities for the first six months of 2013 increased \$192.6 million when compared to the first six months of 2012. The increase in cash flow was primarily due to a \$252.9 million period-to-period increase in cash attributable to overall higher partnership income (after adjusting our \$85.9 million period-to-period increase in net income for changes in the non-cash items identified on our Unaudited Condensed Statements of Consolidated Cash Flows) partially offset by a \$128.9 million period-to-period decrease in cash flow generally attributable to the timing of cash receipts and disbursements related to operations. In addition, cash distributions from unconsolidated affiliates increased \$68.8 million period-to-period primarily due to improved results from our investments in crude oil pipeline joint ventures. For information regarding significant period-to-period changes in our consolidated net income and underlying segment results, see “Results of Operations” within this Item 2.

Investing Activities. Cash used in investing activities for the first six months of 2013 increased \$1.05 billion when compared to the first six months of 2012. The period-to-period increase in cash used for investing activities was primarily due to increased cash contributions to unconsolidated affiliates to fund their capital spending programs and lower cash proceeds received from asset sales, partially offset by lower cash payments for consolidated property, plant and equipment.

Investments in unconsolidated affiliates increased \$422.4 million period-to-period primarily due to contributions we made in connection with expansion projects for the Seaway Pipeline, Texas Express Pipeline, Front Range Pipeline and Eagle Ford Crude Oil Pipeline joint ventures.

Proceeds from asset sales and insurance recoveries decreased from \$1.16 billion for the first six months of 2012 to \$199.2 million for the first six months of 2013. Proceeds for the first six months of 2012 primarily reflect the \$1.1 billion we received in connection with sales of common units of Energy Transfer Equity. For additional information regarding the liquidation of our investment in Energy Transfer Equity, see Note 7 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report. Proceeds for the first six months of 2013 primarily reflect \$86.9 million we received from the sale of the Stratton Ridge-to-Mont Belvieu segment of the Seminole Pipeline, \$35.3 million we received from the sale of lubrication oil and specialty chemical distribution assets, \$29.5 million we received from the sale of chemical trucking assets and \$14.9 million we received from the sale of certain marine transportation assets.

Capital spending for consolidated property, plant and equipment, net of contributions in aid of construction costs, decreased \$370.7 million period-to-period.

Financing Activities. Cash provided by financing activities was \$300.9 million during the first six months of 2013 compared to cash used in financing activities of \$593.8 million during the first six months of 2012. The \$894.7 million change in cash flows attributable to financing activities was primarily due to the following:

- Net cash proceeds from the issuance of common units increased \$773.9 million period-to-period. In total, we issued an aggregate of 15,407,341 common units during the first six months of 2013 in connection with an underwritten offering, the at-the market program and our DRIP and EUPP. We received \$835.4 million of net cash proceeds from these issuances during the first six months of 2013. This compares to 1,270,609 common units we issued during the first six months of 2012 in connection with our DRIP and EUPP. These issuances generated \$61.5 million of net cash proceeds during the first six months of 2012. For additional information regarding our consolidated partners’ equity amounts, see Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.
- Net borrowings under our consolidated debt agreements increased \$259.3 million period-to-period. EPO issued \$2.25 billion and repaid \$1.2 billion in principal amount of senior notes during the first six months of 2013, compared to the issuance of \$750.0 million and repayment of \$500.0 million in principal amount

of senior notes during the first six months of 2012. In addition, net borrowings under EPO's \$3.5 Billion Multi-Year Revolving Credit Facility decreased \$232.0 million period-to-period and net repayments under EPO's commercial paper program during the first six months of 2013 were \$307.1 million. For additional information regarding our consolidated debt obligations, see Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

- Cash contributions from noncontrolling interests increased \$90.0 million period-to-period primarily due to a contribution from Western Gas during the second quarter of 2013 for a 25% noncontrolling interest in a joint venture involving two NGL fractionators that are under construction at our complex in Mont Belvieu, Texas.
- Cash distributions paid to limited partners increased \$103.3 million period-to-period due to increases in the number of distribution-bearing common units outstanding and the quarterly distribution rates per unit.
- Cash payments related to the monetization of interest rate derivative instruments increased \$91.2 million period-to-period. For information regarding our interest rate hedging activities, see Note 4 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Capital Spending Program

An important 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 expand our system of assets through the construction of new facilities and to capitalize on expected increases in natural gas, NGL and crude oil production resulting from development activities in the Rocky Mountains, Midcontinent, Northeast and U.S. Gulf Coast regions, including the Niobrara, Barnett, Eagle Ford, Permian, Haynesville, Marcellus and Utica Shale plays and deepwater Gulf of Mexico production fields.

Although our current focus is on expansion through growth capital projects, management continues to analyze potential business combinations, asset acquisitions, joint ventures and similar transactions with businesses that operate in complementary markets or geographic regions. In past years, major oil and gas companies have sold non-strategic assets in the midstream energy sector in which we operate. We believe this trend will continue and we expect independent oil and natural gas companies to consider similar divestitures.

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

	For the Six Months Ended June 30,	
	2013	2012
Capital spending for property, plant and equipment, net of contributions in aid of construction costs	\$ 1,432.4	\$ 1,803.1
Capital spending for investments in unconsolidated affiliates	547.9	125.5
Other investing activities	--	16.6
Total capital spending	<u>\$ 1,980.3</u>	<u>\$ 1,945.2</u>

Our payments for growth capital spending totaled \$1.8 billion for the six months ended June 30, 2013. Our most significant growth capital expenditures for the first six months of 2013 involved projects in the Eagle Ford Shale, at our Mont Belvieu complex, to expand joint venture crude oil pipelines and for the ATEX Express pipeline.

Based on information currently available, we estimate our consolidated capital spending for 2013 will approximate \$4.6 billion, which includes estimated expenditures of \$4.2 billion for growth capital projects and \$350 million for sustaining capital expenditures. Our forecast of consolidated capital spending for 2013 is net of cash contributions from non-controlling interests in connection with consolidated joint venture growth capital projects. In addition, our forecast of consolidated capital expenditures for 2013 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 equity and debt 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 in connection 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 forecast capital expenditures noted above, we may adjust the timing and amounts of projected expenditures in response to changes in capital markets.

At June 30, 2013, we had approximately \$1.45 billion in purchase commitments outstanding that relate to our capital spending for property, plant and equipment. These commitments primarily relate to construction projects in Texas, the Rocky Mountains and the Northeast U.S.

In the first six months of 2013, we placed \$1.1 billion of capital projects into service. For the remainder of 2013, we expect to complete construction and begin commercial operations related to growth capital spending representing \$1.5 billion of investment. These projects include:

- the Texas Express Pipeline during the third quarter of 2013;
- completion of the remaining segments of the Eagle Ford crude oil pipeline in the joint venture with Plains All American Pipeline, L.P. in the third quarter of 2013;
- two NGL fractionators at Mont Belvieu during the fourth quarter of 2013;
- the Front Range Pipeline during the fourth quarter of 2013; and
- an extension of the Seaway Pipeline from the Jones Creek terminal to our ECHO storage facility during the fourth quarter of 2013.

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.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
Expensed	\$ 16.6	\$ 17.9	\$ 27.3	\$ 36.9
Capitalized	9.8	27.0	22.6	39.9
Total	\$ 26.4	\$ 44.9	\$ 49.9	\$ 76.8

We expect the cost of our pipeline integrity program, regardless of whether such costs are capitalized or expensed, to approximate \$91.0 million for the remainder of 2013. The cost of our pipeline integrity program was \$150.0 million for the year ended December 31, 2012.

Critical Accounting Policies and Estimates

A discussion of our critical accounting policies and estimates is included in our 2012 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; and
- revenue recognition policies and the use of estimates for revenue and expense accruals.

When used to prepare our Unaudited Condensed Consolidated Financial Statements, the foregoing types of estimates are based on our current knowledge and understanding of the underlying facts and circumstances. Such estimates may be revised as a result of changes in the underlying facts and circumstances. Subsequent changes in these estimates may have a significant impact on our consolidated financial position, results of operations and cash flows.

Other Items

Use of Non-GAAP Financial Measures

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.

Our non-GAAP gross operating margin by business segment and in total was as follows for the periods indicated (dollars in millions):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
NGL Pipelines & Services	\$ 544.9	\$ 565.8	\$ 1,137.4	\$ 1,220.7
Onshore Natural Gas Pipelines & Services	197.7	175.8	388.5	382.0
Onshore Crude Oil Pipelines & Services	197.2	95.8	433.6	135.1
Offshore Pipelines & Services	39.7	38.3	80.2	90.4
Petrochemical & Refined Products Services	162.7	157.3	333.6	255.1
Other Investments (1)	--	--	--	2.4
Total segment gross operating margin	\$ 1,142.2	\$ 1,033.0	\$ 2,373.3	\$ 2,085.7

- (1) Represents the equity earnings we recorded from our previously held investment in Energy Transfer Equity. Our reporting for this segment ceased on January 18, 2012 when we stopped using the equity method to account for this investment.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
Total segment gross operating margin	\$ 1,142.2	\$ 1,033.0	\$ 2,373.3	\$ 2,085.7
<i>Adjustments to reconcile total segment gross operating margin to operating income:</i>				
Amounts included in operating costs and expenses:				
Depreciation, amortization and accretion	(289.7)	(261.3)	(566.5)	(515.9)
Non-cash asset impairment charges	(27.1)	(9.1)	(38.1)	(14.5)
Gains (losses) attributable to asset sales and insurance recoveries	(5.7)	29.0	58.2	31.5
General and administrative costs	(45.5)	(42.5)	(95.0)	(88.8)
Operating income	774.2	749.1	1,731.9	1,498.0
Other expense, net	(200.5)	(173.4)	(396.5)	(301.2)
Income before income taxes	\$ 573.7	\$ 575.7	\$ 1,335.4	\$ 1,196.8

For additional information regarding gross operating margin, see Note 11 of the Notes to Unaudited Condensed Consolidated Financial Statements under Part I, Item 1 of this quarterly report.

Contractual Obligations

With the exception of routine fluctuations in the balances of our Multi-Year Revolving Credit Facility and commercial paper notes, the issuance of Senior Notes HH and II in March 2013 and the scheduled repayment of maturing debt obligations, there have been no significant changes in our consolidated debt obligations since those reported in our 2012 Form 10-K. See Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements under Part I, Item 1 of this quarterly report for information regarding our consolidated debt obligations. There were no material changes in our operating lease or purchase obligations since those reported in our 2012 Form 10-K.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements that have or are reasonably expected to have a material current or future effect on our financial position, revenues, expenses, results of operations, liquidity, capital expenditures or capital resources.

Related Party Transactions

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

In October 2009, we issued 4,520,431 Class B units to a privately held affiliate of EPCO in connection with the merger of TEPPCO Partners, L.P. with one of our wholly owned subsidiaries. The Class B units were entitled to vote together with our common units as a single class on partnership matters and generally had the same rights and privileges as our common units, except that the Class B units were not entitled to receive regular quarterly cash distributions until they automatically converted into an equal number of common units on August 8, 2013.

Insurance Matters

For information regarding insurance matters, see Note 15 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, 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 such as futures, forward contracts, swaps, options and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading 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 2012 Form 10-K.

We assess the risk associated with each of our derivative instrument portfolios using a sensitivity analysis model. This approach measures the change in fair value of the derivative instrument portfolio based on a hypothetical 10% change in the underlying interest rates or quoted market prices on a particular day. In addition to these variables, the fair value of each portfolio is influenced by changes in the notional amounts of the instruments outstanding and the discount rates used to determine the present values. The sensitivity analysis approach does 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:

- the derivative instrument functions effectively as a hedge of the underlying risk;
- the derivative instrument is not closed out in advance of its expected term; and
- the hedged forecasted transaction occurs within the expected time period.

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

See Note 4 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report for additional information regarding our derivative instruments and hedging activities.

Interest Rate Hedging Activities

We may utilize interest rate swaps, forward starting swaps 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. The composition of our derivative instrument portfolios may change from period-to-period depending on our hedging requirements.

With respect to the tabular data below, each portfolio’s estimated fair value at a given date is based on a number of factors, including the number and types of derivatives outstanding at that date, the notional value of the swaps and associated interest rates.

Interest rate swaps

Interest rate swaps exchange the stated interest rate paid on a notional amount of existing debt for the fixed or floating interest rate stipulated in the derivative instrument. The following table summarizes our portfolio of interest rate swaps at June 30, 2013 (dollars in millions):

Hedged Transaction	Number and Type of Derivatives Outstanding	Notional Amount	Period of Hedge	Rate Swap	Accounting Treatment
Senior Notes AA	10 fixed-to-floating swaps	\$750.0	1/2011 to 2/2016	3.2% to 1.3%	Fair value hedge
Undesignated swaps	6 floating-to-fixed swaps	\$600.0	5/2010 to 7/2014	0.3% to 2.0%	Mark-to-market

The following table shows the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value (“FV”) of our interest rate swap portfolio at the dates indicated (dollars in millions):

Scenario	Resulting Classification	Interest Rate Swap Portfolio Aggregate Fair Value at		
		December 31, 2012	June 30, 2013	July 16, 2013
FV assuming no change in underlying interest rates	<i>Asset</i>	\$ 28.0	\$ 23.1	\$ 26.4
FV assuming 10% increase in underlying interest rates	<i>Asset</i>	27.2	22.0	25.4
FV assuming 10% decrease in underlying interest rates	<i>Asset</i>	28.8	24.2	27.5

Forward-starting interest rate swaps

Forward starting swaps perform a similar function as traditional interest rate swaps except that they are associated with interest rates underlying anticipated future issuances of debt. The 16 forward starting swaps outstanding at December 31, 2012 with an aggregate notional value of \$1.0 billion were settled at a loss of \$168.8 million in March 2013 in connection with the issuance of Senior Notes HH and II. There were no forward starting swaps outstanding at June 30, 2013.

Commodity Hedging Activities

The prices of natural gas, NGLs, crude oil, refined products and 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 contracts, futures contracts, fixed-for-float swaps, basis swaps and option contracts. The following table summarizes our portfolio of commodity derivative instruments outstanding at June 30, 2013 (volume measures as noted):

Derivative Purpose	Volume (1)		Accounting Treatment
	Current (2)	Long-Term (2)	
Derivatives designated as hedging instruments:			
Octane enhancement:			
Forecasted purchases of NGLs (MMBbls)	1.1	n/a	Cash flow hedge
Forecasted sales of octane enhancement products (MMBbls)	2.2	0.1	Cash flow hedge
Natural gas marketing:			
Forecasted sales of natural gas (Bcf)	2.3	n/a	Cash flow hedge
Natural gas storage inventory management activities (Bcf)	10.0	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	3.3	n/a	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	7.1	n/a	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products (MMBbls)	0.1	n/a	Cash flow hedge
Forecasted sales of refined products (MMBbls)	0.1	n/a	Cash flow hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	2.6	n/a	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	3.0	n/a	Cash flow hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (Bcf) (3,4)	145.7	24.0	Mark-to-market
Refined products risk management activities (MMBbls) (4)	0.5	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (4)	8.5	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 January 2015, February 2014 and March 2016, respectively.
- (3) Current and long-term volumes include 63.9 Bcf and 1.2 Bcf, respectively, of physical derivative instruments that are predominantly priced at a marked-based index plus a premium or minus a discount related to location differences.
- (4) Reflects the use of derivative instruments to manage risks associated with transportation, processing and storage assets.

At August 1, 2013, our predominant commodity hedging strategies consisted of (i) hedging anticipated future contracted sales of NGLs, crude oil, and related products associated with volumes held in inventory and (ii) hedging the fair value of natural gas and refined products in inventory. The following information summarizes these hedging strategies:

- The objective of our NGL, crude oil, and related products 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 and refined products inventory hedging program is to hedge the fair value of natural gas and refined products currently held in inventory by locking in the sales price of the inventory through the use of commodity derivative instruments.

At August 1, 2013, we did not have any hedges in place with respect to gross margins associated with our future natural gas processing activities. Management continues to evaluate market conditions to determine the appropriate timing, if at all, of implementing this strategy during 2013.

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 and crude oil. 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 during the periods originally forecasted. In accordance with derivatives guidance, these instruments do not qualify for hedge accounting even though they are effective at managing the risk exposures of the underlying assets. The earnings volatility caused by fluctuations in non-cash, mark-to-market earnings cannot be predicted.

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 indicated (dollars in millions):

Scenario	Resulting Classification	Portfolio Fair Value at		
		December 31, 2012	June 30, 2013	July 16, 2013
FV assuming no change in underlying commodity prices	Asset	\$ 7.6	\$ 5.3	\$ 3.9
FV assuming 10% increase in underlying commodity prices	Asset (Liability)	3.0	(1.6)	(3.0)
FV assuming 10% decrease in underlying commodity prices	Asset	12.2	12.2	10.8

The following table shows the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value of our NGL marketing, refined products marketing and octane enhancement portfolios at the dates indicated (dollars in millions):

Scenario	Resulting Classification	Portfolio Fair Value at		
		December 31, 2012	June 30, 2013	July 16, 2013
FV assuming no change in underlying commodity prices	Asset (Liability)	\$ 10.5	\$ 1.7	\$ (27.1)
FV assuming 10% increase in underlying commodity prices	Liability	(27.5)	(25.5)	(71.3)
FV assuming 10% decrease in underlying commodity prices	Asset	48.5	28.9	17.1

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 indicated (dollars in millions):

Scenario	Resulting Classification	Portfolio Fair Value at		
		December 31, 2012	June 30, 2013	July 16, 2013
FV assuming no change in underlying commodity prices	Asset (Liability)	\$ (2.0)	\$ 6.9	\$ 4.8
FV assuming 10% increase in underlying commodity prices	Liability	(10.0)	(0.2)	(2.6)
FV assuming 10% decrease in underlying commodity prices	Asset	6.1	13.9	12.1

Item 4. Controls and Procedures.

Disclosure Controls and Procedures

As of the end of the period covered by this quarterly report, our management carried out an evaluation, with the participation of our general partner's chief executive officer, Michael A. Creel (our principal executive officer), and chief financial officer, W. Randall Fowler (our principal financial officer), 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, Mr. Creel and Mr. Fowler 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 our principal executive and financial officers, as appropriate to allow for timely decisions regarding required disclosures; 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 2013, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

The required certifications of Mr. Creel and Mr. Fowler under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 are included as exhibits to this quarterly report (see Exhibits 31 and 32 under Part II, Item 6 of this quarterly report).

PART II. OTHER INFORMATION

Item 1. *Legal Proceedings.*

For information regarding litigation matters, see Note 14, “Commitments and Contingencies,” 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.

Item 1A. *Risk Factors.*

Security holders and potential investors in our securities should carefully consider the risk factors set forth in our 2012 Form 10-K, in addition to other information in our annual report. The risk factors set forth in our 2012 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.*

The following table summarizes our repurchase activity during the six months ended June 30, 2013:

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 2013 (1)	315,783	\$55.78	--	--
May 2013 (2)	298,408	\$60.65	--	--

- (1) Of the 939,226 restricted common units that vested in February 2013 and converted to common units, 315,783 units were sold back to us by employees to cover related withholding tax requirements.
- (2) Of the 890,784 restricted common units that vested in May 2013 and converted to common units, 298,408 units were sold back to us by employees to cover related withholding tax requirements.

Item 3. *Defaults Upon Senior Securities.*

None.

Item 4. *Mine Safety Disclosures.*

Not applicable.

Item 5. Other Information.

None.

Item 6. Exhibits.

Exhibit Number	Exhibit*
2.1	Merger Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed December 15, 2003).
2.2	Amendment No. 1 to Merger Agreement, dated as of August 31, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed September 7, 2004).
2.3	Parent Company Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.2 to Form 8-K filed December 15, 2003).
2.4	Amendment No. 1 to Parent Company Agreement, dated as of April 19, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.1 to Form 8-K filed April 21, 2004).
2.5	Purchase and Sale Agreement (Gas Plants), dated as of December 15, 2003, by and between El Paso Corporation, El Paso Field Services Management, Inc., El Paso Transmission, L.L.C., El Paso Field Services Holding Company and Enterprise Products Operating L.P. (incorporated by reference to Exhibit 2.4 to Form 8-K filed December 15, 2003).
2.6	Agreement and Plan of Merger, dated as of June 28, 2009, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Sub B LLC, TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed June 29, 2009).
2.7	Agreement and Plan of Merger, dated as of June 28, 2009, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Sub A LLC, TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (incorporated by reference to Exhibit 2.2 to Form 8-K filed June 29, 2009).
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 Amendment No. 1 to Sixth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated effective as of August 11, 2011 (incorporated by reference to Exhibit 3.1 to Form 8-K filed August 16, 2011).
- 3.5 Certificate of Formation of Enterprise Products Holdings LLC (formerly named 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).
- 3.6 Certificate of Amendment to Certificate of Formation of Enterprise Products Holdings LLC (formerly named 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).
- 3.7 Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products Holdings LLC dated effective as of September 7, 2011 (incorporated by reference to Exhibit 3.1 to Form 8-K filed September 8, 2011).
- 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 A to Exhibit 3.1 to Form 8-K filed August 16, 2011).
- 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 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).
- 4.8 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).

- 4.9 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).
- 4.10 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).
- 4.11 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).
- 4.12 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).
- 4.13 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).
- 4.14 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).
- 4.15 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).
- 4.16 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).
- 4.17 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).
- 4.18 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).
- 4.19 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).
- 4.20 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).
- 4.21 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).
- 4.22 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).

- 4.23 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).
- 4.24 Twenty-First Supplemental Indenture, dated as of August 24, 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 August 24, 2011).
- 4.25 Twenty-Second Supplemental Indenture, dated as of February 15, 2012, 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 4.25 to Form 10-Q filed May 10, 2012).
- 4.26 Twenty-Third Supplemental Indenture, dated as of August 13, 2012, 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 August 13, 2012).
- 4.27 Twenty-Fourth Supplemental Indenture, dated as of March 18, 2013, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed March 18, 2013).
- 4.28 Form of Global Note representing \$350.0 million principal amount of 6.375% Series B Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
- 4.29 Form of 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 4.8 to Form 10-K filed March 31, 2003).
- 4.30 Form of 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 Form of 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 Form of 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 Form of 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 Form of 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 Form of Junior Subordinated Note, including Guarantee (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006).
- 4.36 Form of Global Note representing \$800.0 million principal amount of 6.30% Senior Notes due 2017 with attached Guarantee (incorporated by reference to Exhibit 4.38 to Form 10-Q filed November 9, 2007).
- 4.37 Form of Global Note representing \$400.0 million principal amount of 5.65% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed April 3, 2008).
- 4.38 Form of Global Note representing \$700.0 million principal amount of 6.50% Senior Notes due 2019 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed April 3, 2008).
- 4.39 Form of Global Note representing \$500.0 million principal amount of 9.75% Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed December 8, 2008).
- 4.40 Form of Global Note representing \$500.0 million principal amount of 4.60% Senior Notes due

- 2012 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed June 10, 2009).
- 4.41 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).
- 4.42 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).
- 4.43 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).
- 4.44 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).
- 4.45 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).
- 4.46 Form of Global Note representing \$349.7 million principal amount of 6.65% Senior Notes due 2018 with attached Guarantee (incorporated by reference to Exhibit 4.6 to Form 8-K filed October 28, 2009).
- 4.47 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).
- 4.48 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).
- 4.49 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).
- 4.50 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).
- 4.51 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).
- 4.52 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).
- 4.53 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).
- 4.54 Form of Global Note representing \$650.0 million principal amount of 4.05% Senior Notes due 2022 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed August 24, 2011).
- 4.55 Form of Global Note representing \$600.0 million principal amount of 5.70% Senior Notes due 2042 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed August 24, 2011).
- 4.56 Form of Global Note representing \$750.0 million principal amount of 4.85% Senior Notes due 2042 with attached Guarantee (included in Exhibit 4.25 above).
- 4.57 Form of Global Note representing \$650.0 million principal amount of 1.25% Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed August 13, 2012).
- 4.58 Form of Global Note representing \$1.1 billion principal amount of 4.45% Senior Notes due 2043 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed August 13, 2012).
- 4.59 Form of Global Note representing \$1.25 billion principal amount of 3.35% Senior Notes due

- 2023 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed March 18, 2013).
- 4.60 Form of Global Note representing \$1.0 billion principal amount of 4.85% Senior Notes due 2044 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed March 18, 2013).
- 4.61 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).
- 4.62 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).
- 4.63 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).
- 4.64 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).
- 4.65 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).
- 4.66 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).
- 4.67 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).
- 4.68 Full Release of Guarantee, dated July 31, 2006, by Wachovia Bank, National Association, as Trustee, in favor of Jonah Gas Gathering Company (incorporated by reference to Exhibit 4.8 to the Form 10-Q filed by TEPPCO Partners, L.P. on November 7, 2006).
- 4.69 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).
- 4.70 Fifth Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.11 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008).
- 4.71 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).

- 4.72 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).
- 4.73 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).
- 4.74 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).
- 4.75 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).
- 4.76 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).
- 4.77 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).
- 4.78 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).
- 4.79 Third Supplemental Indenture, dated as of October 27, 2009, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TEPPCO Partners, L.P. on October 28, 2009).
- 4.80 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).
- 10.1 364-Day Revolving Credit Agreement dated as of June 19, 2013, among Enterprise Products Operating LLC, the Lenders party thereto, Wells Fargo Bank, National Association, as Administrative Agent and Swingline Lender, Citibank, N.A., DNB Bank ASA, New York Branch, JPMorgan Chase Bank, N.A., Mizuho Corporate Bank, Ltd., and The Royal Bank of Scotland Plc, as Co-Syndication Agents, and The Bank of Nova Scotia, SunTrust Bank, The Bank of Tokyo-Mitsubishi UFJ, Ltd., UBS Securities LLC and Royal Bank of Canada, as Co-Documentation Agents (incorporated by reference to Exhibit 10.1 to Form 8-K filed on June 20, 2013).
- 10.2 Guaranty Agreement, dated as of June 19, 2013, by Enterprise Products Partners L.P. in favor of Wells Fargo Bank, National Association, as Administrative Agent (incorporated by reference to Exhibit 10.2 to Form 8-K filed on June 20, 2013).

- 10.3 First Amendment dated as of June 19, 2013 to Revolving Credit Agreement dated as of September 7, 2011, among Enterprise Products Operating LLC, Canadian Enterprise Gas Products, Ltd., Wells Fargo Bank, National Association, as administrative agent for each of the lenders that is a signatory or which becomes a signatory to the Credit Agreement, the Lenders party thereto, Citibank, N.A., DNB Bank ASA, New York Branch, JPMorgan Chase Bank, N.A., Mizuho Corporate Bank, Ltd. and The Royal Bank of Scotland Plc, as Co-Syndication Agents, and The Bank of Nova Scotia, SunTrust Bank, The Bank of Tokyo-Mitsubishi UFJ, Ltd., UBS Securities LLC and Royal Bank of Canada, as Co-Documentation Agents, and Wells Fargo Securities, LLC, Citigroup Global Markets Inc., DNB Markets, Inc., J.P. Morgan Securities LLC, Mizuho Corporate Bank, Ltd., RBS Securities Inc., Scotia Capital, SunTrust Robinson Humphrey, Inc., and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Joint Lead Arrangers and Joint Book Runners (incorporated by reference to Exhibit 10.3 to Form 8-K filed on June 20, 2013).
- 12.1# Computation of ratio of earnings to fixed charges for the six months ended June 30, 2013 and for each of the five years ended December 31, 2012, 2011, 2010, 2009 and 2008.
- 31.1# Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise Products Partners L.P.'s quarterly report on Form 10-Q for the period ended June 30, 2013.
- 31.2# Sarbanes-Oxley Section 302 certification of W. Randall Fowler for Enterprise Products Partners L.P.'s quarterly report on Form 10-Q for the period ended June 30, 2013.
- 32.1# Sarbanes-Oxley Section 906 certification of Michael A. Creel for Enterprise Products Partners L.P.'s quarterly report on Form 10-Q for the period ended June 30, 2013.
- 32.2# Sarbanes-Oxley Section 906 certification of W. Randall Fowler for Enterprise Products Partners L.P.'s quarterly report on Form 10-Q for the period ended June 30, 2013.
- 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.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on August 8, 2013.

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