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 September 30, 2013

OR

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

For the transition period from ___ to ___.

Commission file number: 1-14323

ENTERPRISE PRODUCTS PARTNERS L.P.

(Exact Name of Registrant as Specified in Its Charter)

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

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

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

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

Yes ☑ No o

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

Yes ☑ No ☐

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

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

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

Yes o No ☑

There were 925,104,465 common units of Enterprise Products Partners L.P. outstanding at October 31, 2013. Our common units trade on the New York Stock Exchange under the ticker symbol "EPD."

ENTERPRISE PRODUCTS PARTNERS L.P.
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PART I. FINANCIAL INFORMATION.

Item 1. *Financial Statements*.

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

ASSETS	September 30, 2013	December 31, 2012
Current assets:		
Cash and cash equivalents	$ 9.6	$ 16.1
Restricted cash	35.9	4.3
Accounts receivable – trade, net of allowance for doubtful accounts of $6.7 at September 30, 2013 and $13.2 at December 31, 2012	5,469.1	4,350.9
Accounts receivable – related parties	12.8	2.5
Inventories	1,862.4	1,088.4
Prepaid and other current assets	381.1	380.9
Total current assets	7,770.9	5,843.1
Property, plant and equipment, net	26,453.9	24,846.4
Investments in unconsolidated affiliates	2,134.5	1,394.6
Intangible assets, net of accumulated amortization of $1,124.6 at September 30, 2013 and $1,050.0 at December 31, 2012	1,487.6	1,566.8
Goodwill	2,080.0	2,086.8
Other assets	198.1	196.7
Total assets	$ 40,125.0	$ 35,934.4
LIABILITIES AND EQUITY		
Current liabilities:		
Current maturities of debt (see Note 9)	$ 1,049.9	$ 1,546.6
Accounts payable – trade	1,040.3	764.5
Accounts payable – related parties	96.5	127.1
Accrued product payables	5,972.8	4,476.2
Accrued interest	168.2	300.8
Other current liabilities	396.1	540.5
Total current liabilities	8,723.8	7,755.7
Long-term debt (see Note 9)	16,481.6	14,655.2
Deferred tax liabilities	55.0	22.5
Other long-term liabilities	182.4	205.0
Commitments and contingencies (see Note 14)		
Equity: (see Note 10)		
Partners' equity:		
Limited partners:		
Common units (924,770,538 units outstanding at September 30, 2013 and 898,813,337 units outstanding at December 31, 2012)	14,821.4	13,439.6
Class B units (4,520,431 units outstanding at December 31, 2012)	--	118.5
Total limited partners' equity	14,821.4	13,558.1
Accumulated other comprehensive loss	(349.3)	(370.4)
Total partners' equity	14,472.1	13,187.7
Noncontrolling interests	210.1	108.3
Total equity	14,682.2	13,296.0
Total liabilities and equity	$ 40,125.0	$ 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 September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
Revenues:				
Third parties	$ 12,085.6	$ 10,461.2	$ 34,605.4	$ 31,447.1
Related parties	7.7	7.5	20.3	63.9
Total revenues (see Note 11)	12,093.3	10,468.7	34,625.7	31,511.0
Costs and expenses:				
Operating costs and expenses:				
Third parties	11,055.3	9,456.6	31,404.5	28,563.4
Related parties	218.2	203.2	656.6	573.1
Total operating costs and expenses	11,273.5	9,659.8	32,061.1	29,136.5
General and administrative costs:				
Third parties	17.4	18.8	54.6	59.1
Related parties	26.5	22.6	84.3	71.1
Total general and administrative costs	43.9	41.4	138.9	130.2
Total costs and expenses (see Note 11)	11,317.4	9,701.2	32,200.0	29,266.7
Equity in income of unconsolidated affiliates	44.0	21.0	126.1	42.2
Operating income	819.9	788.5	2,551.8	2,286.5
Other income (expense):				
Interest expense	(208.3)	(199.7)	(604.4)	(572.8)
Interest income	0.2	0.3	0.7	0.7
Other, net (see Note 2)	0.4	1.2	(0.5)	72.7
Total other expense, net	(207.7)	(198.2)	(604.2)	(499.4)
Income before income taxes	612.2	590.3	1,947.6	1,787.1
Benefit from (provision for) income taxes (see Note 2)	(19.4)	(2.4)	(46.2)	23.5
Net income	592.8	587.9	1,901.4	1,810.6
Net income attributable to noncontrolling interests (see Note 10)	(0.8)	(1.1)	(3.4)	(6.2)
Net income attributable to limited partners	$ 592.0	$ 586.8	$ 1,898.0	$ 1,804.4
Earnings per unit: (see Note 13)				
Basic earnings per unit	$ 0.66	$ 0.68	$ 2.13	$ 2.10
Diluted earnings per unit	$ 0.64	$ 0.66	$ 2.07	$ 2.03

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 September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
Net income	$ 592.8	$ 587.9	$ 1,901.4	$ 1,810.6
Other comprehensive income (loss):				
Cash flow hedges:				
Commodity derivative instruments:				
Changes in fair value of cash flow hedges	(8.6)	(58.5)	(22.1)	(13.1)
Reclassification of losses to net income	14.6	0.9	14.7	37.1
Interest rate derivative instruments:				
Changes in fair value of cash flow hedges	--	(20.2)	6.7	(75.3)
Reclassification of losses to net income	7.7	4.5	21.4	10.9
Total cash flow hedges	13.7	(73.3)	20.7	(40.4)
Other	--	3.7	0.4	3.5
Total other comprehensive income (loss)	13.7	(69.6)	21.1	(36.9)
Comprehensive income	606.5	518.3	1,922.5	1,773.7
Comprehensive income attributable to noncontrolling interests	(0.8)	(1.1)	(3.4)	(6.2)
Comprehensive income attributable to limited partners	$ 605.7	$ 517.2	$ 1,919.1	$ 1,767.5

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 Nine Months Ended September 30, 2013	For the Nine Months Ended September 30, 2012
Operating activities:		
Net income	$ 1,901.4	$ 1,810.6
Reconciliation of net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	902.3	817.9
Non-cash asset impairment charges	53.3	57.6
Equity in income of unconsolidated affiliates	(126.1)	(42.2)
Distributions received from unconsolidated affiliates	187.6	67.5
Gains attributable to asset sales and insurance recoveries (see Note 16)	(68.4)	(102.9)
Deferred income tax expense (benefit)	32.1	(67.9)
Changes in fair market value of derivative instruments	(5.3)	(15.9)
Net effect of changes in operating accounts (see Note 16)	(513.9)	(910.2)
Other operating activities	3.2	1.3
Net cash flows provided by operating activities	2,366.2	1,615.8
Investing activities:		
Capital expenditures	(2,413.2)	(2,716.1)
Contributions in aid of construction costs	19.9	18.2
Decrease (increase) in restricted cash	(31.6)	19.7
Investments in unconsolidated affiliates	(768.4)	(351.8)
Proceeds from asset sales and insurance recoveries (see Note 16)	256.3	1,167.4
Other investing activities	(0.5)	(32.4)
Cash used in investing activities	(2,937.5)	(1,895.0)
Financing activities:		
Borrowings under debt agreements	10,139.2	7,141.4
Repayments of debt	(8,791.6)	(5,716.0)
Debt issuance costs	(23.7)	(20.7)
Monetization of interest rate derivative instruments (see Note 4)	(168.8)	(147.8)
Cash distributions paid to limited partners (see Note 10)	(1,778.3)	(1,613.4)
Cash distributions paid to noncontrolling interests	(6.4)	(11.3)
Cash contributions from noncontrolling interests (see Note 10)	104.2	6.5
Net cash proceeds from the issuance of common units	1,134.7	658.6
Acquisition of treasury units	(36.1)	(19.6)
Other financing activities	(8.4)	(3.8)
Cash provided by financing activities	564.8	273.9
Net change in cash and cash equivalents	(6.5)	(5.3)
Cash and cash equivalents, January 1	16.1	19.8
Cash and cash equivalents, September 30	$ 9.6	$ 14.5

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	1,898.0	--	3.4	1,901.4
Cash distributions paid to limited partners	(1,778.3)	--	--	(1,778.3)
Cash distributions paid to noncontrolling interests	--	--	(6.4)	(6.4)
Cash contributions from noncontrolling interests	--	--	104.2	104.2
Net cash proceeds from the issuance of common units	1,134.7	--	--	1,134.7
Amortization of fair value of equity-based awards	53.5	--	--	53.5
Cash flow hedges	--	20.7	--	20.7
Other	(44.6)	0.4	0.6	(43.6)
Balance, September 30, 2013	$ 14,821.4	$ (349.3)	$ 210.1	$ 14,682.2

	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	1,804.4	--	6.2	1,810.6
Cash distributions paid to limited partners	(1,613.4)	--	--	(1,613.4)
Cash distributions paid to noncontrolling interests	--	--	(11.3)	(11.3)
Cash contributions from noncontrolling interests	--	--	6.5	6.5
Net cash proceeds from the issuance of common units	658.6	--	--	658.6
Amortization of fair value of equity-based awards	45.9	--	--	45.9
Cash flow hedges	--	(40.4)	--	(40.4)
Other	(22.4)	3.5	1.0	(17.9)
Balance, September 30, 2012	$ 13,337.9	$ (388.3)	$ 108.3	$ 13,057.9

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 and Organization

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 (including liquefied petroleum gas or "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 51,000 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, 22 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, 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 related party matters.

Note 2. General Accounting Matters

Our results of operations for the three and nine months ended September 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 Nine Months Ended September 30,	
	2013	2012
Balance at beginning of period	$ 13.2	$ 13.4
Charged to costs and expenses	1.2	0.2
Deductions	(7.7)	(0.4)
Balance at end of period	$ 6.7	$ 13.2

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.

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 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 primarily reflects our state tax obligations under the Revised Texas Franchise Tax (the "Texas Margin Tax"). Deferred income tax assets and liabilities are recognized for temporary differences between the assets and liabilities of our tax paying entities for financial reporting and tax purposes.

We recognized an overall net income tax benefit of $23.5 million for the nine months ended September 30, 2012 that was primarily due to a $46.5 million net income tax benefit related to the conversion of certain of our subsidiaries to limited liability companies during the first quarter of 2012, partially offset by accruals for the Texas Margin Tax. 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 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.

We recognized a net income tax expense of $46.2 million for the nine months ended September 30, 2013, of which $19.6 million of expense was attributable to certain legislative changes to the Texas Margin Tax enacted during the second quarter of 2013. Our current provision for income taxes was $14.1 million and our deferred income tax expense was $32.1 million for the nine months ended September 30, 2013.

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 September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
Gain on sales of available-for-sale securities of Energy Transfer Equity (1)	$ --	$ --	$ --	$ 68.8
Distribution income from Energy Transfer Equity	--	--	--	4.1
Other	0.4	1.2	(0.5)	(0.2)
Total	$ 0.4	$ 1.2	$ (0.5)	$ 72.7

(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 and sales. Additional cash may be restricted to maintain this portfolio as commodity prices fluctuate or deposit requirements change. At September 30, 2013 and December 31, 2012, our restricted cash amounts were $35.9 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 September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
Restricted common unit awards	$ 17.8	$ 13.8	$ 52.7	$ 44.3
Unit option awards	0.1	0.2	0.7	1.2
Other (1)	0.1	0.2	0.4	1.6
Total	$ 18.0	$ 14.2	$ 53.8	$ 47.1

(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 September 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 2008 Enterprise Products Long-Term Incentive Plan (Third Amendment and Restatement) ("2008 Plan").

In September 2013, our unitholders approved the third amendment and restatement of the 2008 Plan, which was also approved by the Audit and Conflicts Committee (the "AC Committee") of the board of directors of our general partner. The 2008 Plan (as amended and restated) is a long-term incentive plan under which any employee or consultant of EPCO, us or our affiliates that provides services to us, directly or indirectly, may receive incentive compensation awards in the form of options, restricted units, phantom units, distribution equivalent rights, UARs, unit awards, other unit-based awards or substitute awards. Non-employee directors of our general partner may also participate in the 2008 Plan.

The 2008 Plan is administered by the AC Committee, which has significant authority thereunder to, among other things, (i) designate participants; (ii) determine the type or types of award(s) and the number of common units to be covered by any award; (iii) determine the terms and conditions of any award; and (iv) determine whether, to what extent and under what circumstances participants may settle, exercise, cancel or forfeit any award.

The maximum number of common units available for issuance under the 2008 Plan is currently 10,000,000, and will automatically increase under the terms of the 2008 Plan by 2,500,000 common units per year, beginning on January 1, 2014 and subsequently on each January 1 thereafter during the term of the 2008 Plan; provided, however, that in no event shall the maximum aggregate number exceed 35,000,000 common units. The 2008 Plan is effective until September 30, 2023 or, if earlier, at the time that all available common units under the 2008 Plan have been delivered to participants or the time of termination of the 2008 Plan by the board of directors of EPCO or by the AC Committee.

After giving effect to awards granted under the 1998 Plan and 2008 Plan through September 30, 2013 and the September 2013 amendments reflected in the 2008 Plan, a total of 1,151,778 and 4,333,287 additional common units could be issued under these plans, respectively, as of September 30, 2013.

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)	1,769,076	$ 57.20
Vested (3)	(1,846,198)	$ 34.77
Forfeited	(159,832)	$ 47.40
Restricted common units at September 30, 2013	3,656,532	$ 51.56

(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 $101.2 million based on a grant date market price of our common units ranging from $57.11 to $61.58 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 September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
Cash distributions paid to restricted common unitholders	$ 2.6	$ 2.5	$ 8.2	$ 7.9
Total intrinsic value of restricted common unit awards that vested during period	1.0	1.5	107.4	64.2

For the EPCO group of companies, the unrecognized compensation cost associated with restricted common unit awards was an aggregate $91.3 million at September 30, 2013, of which our allocated share of the cost is currently estimated to be $83.4 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.0 years.

Unit Option Awards

EPCO's long-term incentive plans provide for the issuance of non-qualified incentive options. These unit option awards 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 September 30, 2013	2,025,000	$ 26.49	1.6	$ 50.0
Options exercisable at September 30, 2013	--	$ --	--	$ --

(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 Nine Months Ended September 30,	
	2013	2012
Total intrinsic value of unit option awards exercised during period	$ 19.8	$ 14.0
Cash received from EPCO in connection with the exercise of unit option awards	11.5	10.2
Unit option award-related cash reimbursements to EPCO	19.8	14.0

There were no option exercises or related cash receipts or reimbursements during the three months ended September 30, 2013 or 2012.

For the EPCO group of companies, the unrecognized compensation cost associated with unit option awards was an aggregate $0.2 million at September 30, 2013. We expect to be allocated substantially all of the cost of these awards over a weighted-average period of 0.4 years.

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.

The following table summarizes our portfolio of interest rate swaps at September 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 1.2%	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.

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 loss 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 loss 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 EPO's issuance of Senior Notes FF and Senior Notes GG in August 2012, we settled seven forward starting swaps having an aggregate notional amount of $350.0 million, resulting in cash losses of $70.2 million. These losses are reflected in accumulated other comprehensive loss and will be amortized to earnings (as an increase in interest expense) over the forecasted hedged period of ten years using the effective interest method.

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 September 30, 2013 (volume measures as noted):

	Volume (1)		Accounting
Derivative Purpose	**Current** (2)	**Long-Term** (2)	**Treatment**
Derivatives designated as hedging instruments:			
Natural gas processing:			
Forecasted sales of NGLs (MMBbls)	0.1	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchases of NGLs (MMBbls)	1.0	n/a	Cash flow hedge
Forecasted sales of octane enhancement products (MMBbls)	3.2	0.7	Cash flow hedge
Natural gas marketing:			
Forecasted sales of natural gas (Bcf)	2.4	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)	3.6	n/a	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	7.3	n/a	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products (MMBbls)	0.8	n/a	Cash flow hedge
Forecasted sales of refined products (MMBbls)	1.0	n/a	Cash flow hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	3.7	0.3	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	5.1	0.5	Cash flow hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (Bcf) (3,4)	112.2	23.8	Mark-to-market
Refined products risk management activities (MMBbls) (4)	0.6	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (4)	11.0	0.9	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, May 2014 and October 2016, respectively.
(3) Current and long-term volumes include 52.0 Bcf and 0.3 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 September 30, 2013, our predominant commodity hedging strategies consisted of (i) hedging anticipated future purchases and sales of commodity products associated with transportation, storage and blending activities, (ii) hedging the fair value of commodity products held in inventory, (iii) hedging natural gas processing margins, and (iv) hedging octane enhancement margins. The following information summarizes these hedging strategies:

§ The objective of our anticipated future commodity purchases and sales hedging program is to hedge the margins of certain transportation, storage and blending activities by locking in purchases and sales prices through the use of forward contracts and derivative instruments.

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

§ The objective of our natural gas processing hedging program is to hedge an amount of gross margin associated with these activities. We achieve this objective by executing forward fixed-price sales of a portion of our expected equity NGL production using forward contracts and commodity derivative instruments. For certain natural gas processing contracts, the hedging of expected equity NGL production also involves the purchase of natural gas for plant thermal reduction, which is hedged by executing forward fixed-price purchases using forward contracts and derivative instruments.

§ The objective of our octane enhancement hedging program is to hedge an amount of gross margin associated with these activities. We achieve this objective by executing forward fixed-price sales of a portion of our expected octane enhancement product volumes and forward fixed-price purchases of NGL feedstocks using forward contracts and derivative instruments.

Certain basis swaps, basis spread options and other derivative instruments not designated as hedging instruments are used to manage market risks associated with anticipated purchases and sales of commodity products. 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 accounting guidance, these instruments do not qualify for hedge accounting even though they are effective at managing the risk exposures of the underlying assets. Due to volatility in commodity prices, any non-cash, mark-to-market earnings variability 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			
	September 30, 2013		December 31, 2012		September 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	$ 16.5	Other current assets	$ 19.6	Other current liabilities	$ --	Other current liabilities	$ 175.4
Interest rate derivatives	Other assets	14.9	Other assets	25.6	Other liabilities	--	Other liabilities	--
Total interest rate derivatives		31.4		45.2		--		175.4
Commodity derivatives	Other current assets	46.6	Other current assets	45.3	Other current liabilities	45.8	Other current liabilities	35.4
Commodity derivatives	Other assets	4.2	Other assets	--	Other liabilities	1.6	Other liabilities	0.5
Total commodity derivatives		50.8		45.3		47.4		35.9
Total derivatives designated as hedging instruments		$ 82.2		$ 90.5		$ 47.4		$ 211.3
Derivatives not designated as hedging instruments								
Interest rate derivatives	Other current assets	$ --	Other current assets	$ --	Other current liabilities	$ 10.3	Other current liabilities	$ 12.2
Interest rate derivatives	Other assets	--	Other assets	--	Other liabilities	--	Other liabilities	5.0
Total interest rate derivatives		--		--		10.3		17.2
Commodity derivatives	Other current assets	16.1	Other current assets	15.7	Other current liabilities	2.5	Other current liabilities	8.9
Commodity derivatives	Other assets	2.6	Other assets	0.6	Other liabilities	2.0	Other liabilities	0.7
Total commodity derivatives		18.7		16.3		4.5		9.6
Total derivatives not designated as hedging instruments		$ 18.7		$ 16.3		$ 14.8		$ 26.8

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 Not Offset in the Balance Sheet			
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Amounts of Assets Presented in the Balance Sheet	Financial Instruments	Cash Collateral Received	Cash Collateral Paid	Amounts That Would Have Been Presented On Net Basis
	(i)	(ii)	(iii) = (i) – (ii)	(iv)			(v) = (iii) + (iv)
As of September 30, 2013:							
Commodity derivatives	$ 69.5	$ --	$ 69.5	$ (44.9)	$ --	$ (16.1)	$ 8.5
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 Not Offset in the Balance Sheet		
	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Balance Sheet	Amounts of Liabilities Presented in the Balance Sheet	Financial Instruments	Cash Collateral Paid	Amounts That Would Have Been Presented On Net Basis
	(i)	(ii)	(iii) = (i) – (ii)	(iv)		(v) = (iii) + (iv)
As of September 30, 2013:						
Commodity derivatives	$ 51.9	$ --	$ 51.9	$ (44.9)	$ --	$ 7.0
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.

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

Derivatives in Fair Value Hedging Relationships	Location	Gain (Loss) Recognized in Income on Derivative			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2013	2012	2013	2012
Interest rate derivatives	Interest expense	$ (0.5)	$ 3.0	$ (10.6)	$ 6.1
Commodity derivatives	Revenue	(3.1)	(0.4)	3.1	(16.1)
Total		$ (3.6)	$ 2.6	$ (7.5)	$ (10.0)

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Derivatives in Fair Value Hedging Relationships	Location	Gain (Loss) Recognized in Income on Hedged Item			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2013	2012	2013	2012
Interest rate derivatives	Interest expense	$ 0.4	$ (2.9)	$ 10.3	$ (6.3)
Commodity derivatives	Revenue	(0.4)	(1.8)	(12.0)	14.5
Total		$ --	$ (4.7)	$ (1.7)	$ 8.2

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:

Derivatives in Cash Flow Hedging Relationships	Change in Value Recognized in Other Comprehensive Income (Loss) on Derivative (Effective Portion)			
	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
Interest rate derivatives	$ --	$ (20.2)	$ 6.7	$ (75.3)
Commodity derivatives – Revenue (1)	(8.6)	(59.5)	(22.1)	0.7
Commodity derivatives – Operating costs and expenses (1)	--	1.0	--	(13.8)
Total	$ (8.6)	$ (78.7)	$ (15.4)	$ (88.4)

(1) The fair value of these derivative instruments would be reclassified to their respective locations on the Statement of Consolidated Operations upon settlement of the underlying derivative transactions, as appropriate.

Derivatives in Cash Flow Hedging Relationships	Location	Gain (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) to Income (Effective Portion)			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2013	2012	2013	2012
Interest rate derivatives	Interest expense	$ (7.7)	$ (4.5)	$ (21.4)	$ (10.9)
Commodity derivatives	Revenue	(14.6)	0.3	(15.1)	(12.3)
Commodity derivatives	Operating costs and expenses	--	(1.2)	0.4	(24.8)
Total		$ (22.3)	$ (5.4)	$ (36.1)	$ (48.0)

Derivatives in Cash Flow Hedging Relationships	Location	Gain (Loss) Recognized in Income on Derivative (Ineffective Portion)			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2013	2012	2013	2012
Commodity derivatives	Revenue	$ 0.1	$ (1.1)	$ --	$ (0.2)
Commodity derivatives	Operating costs and expenses	--	0.1	--	0.4
Total		$ 0.1	$ (1.0)	$ --	$ 0.2

Over the next twelve months, we expect to reclassify $31.7 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 $0.2 million of gains attributable to commodity derivative instruments from accumulated other comprehensive loss to earnings as an increase in revenue.

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

Derivatives Not Designated as Hedging Instruments	Location	Gain (Loss) Recognized in Income on Derivative			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2013	2012	2013	2012
Interest rate derivatives	Interest expense	$ (0.5)	$ (2.2)	$ (0.6)	$ (5.5)
Commodity derivatives	Revenue	8.1	(3.9)	17.0	26.2
Commodity derivatives	Operating costs and expenses	--	--	--	(2.8)
Total		$ 7.6	$ (6.1)	$ 16.4	$ 17.9

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 tables set forth, by level within the fair value hierarchy, the carrying values of our financial assets and liabilities at December 31, 2012 and September 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.

	December 31, 2012 Fair Value Measurements Using			
	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Carrying Value at December 31, 2012
Financial assets:				
Interest rate derivatives	$ --	$ 45.2	$ --	$ 45.2
Commodity derivatives	11.4	47.8	2.4	61.6
Total	$ 11.4	$ 93.0	$ 2.4	$ 106.8
Financial liabilities:				
Interest rate derivatives	$ --	$ 192.6	$ --	$ 192.6
Commodity derivatives	13.1	28.5	3.9	45.5
Total	$ 13.1	$ 221.1	$ 3.9	$ 238.1

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	September 30, 2013 Fair Value Measurements Using			
	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Carrying Value at September 30, 2013
Financial assets:				
Interest rate derivatives	$ --	$ 31.4	$ --	$ 31.4
Commodity derivatives	34.0	33.2	2.3	69.5
Total	$ 34.0	$ 64.6	$ 2.3	$ 100.9
Financial liabilities:				
Interest rate derivatives	$ --	$ 10.3	$ --	$ 10.3
Commodity derivatives	19.5	30.2	2.2	51.9
Total	$ 19.5	$ 40.5	$ 2.2	$ 62.2

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:

	Location	For the Nine Months Ended September 30, 2013	2012
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		(0.2)	4.9
Total gains (losses) included in:			
Net income (1)	Revenue	1.1	(0.6)
Other comprehensive income	Commodity derivative instruments – changes in fair value of cash flow hedges	(0.9)	3.5
Settlements	Revenue	0.1	1.4
Financial asset (liability) balance, net, September 30 (2)		$ 0.1	$ 9.2

(1) There were unrealized gains of $1.1 million and $2.4 million included in these amounts for the three and nine months ended September 30, 2013, respectively. There were $0.8 million of unrealized gains and $1.1 million of unrealized losses included in these amounts for the three and nine months ended September 30, 2012, respectively.
(2) There were no transfers into or out of Level 3 during the three or nine months ended September 30, 2013.

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

	Fair Value Financial Assets	Financial Liabilities	Valuation Techniques	Unobservable Input	Range
Commodity derivatives:					
Crude oil	$ 1.4	$ 0.2	Discounted cash flow	Forward commodity prices	$91.87-$103.07/barrel
Propane	0.1	--	Discounted cash flow	Forward commodity prices	$0.97-$1.07/gallon
Normal butane	--	0.1	Discounted cash flow	Forward commodity prices	$1.26-$1.38/gallon
Natural gasoline	0.6	1.4	Discounted cash flow	Forward commodity prices	$1.92-$2.07/gallon
Natural gas	0.2	0.5	Discounted cash flow	Forward commodity prices	$3.26-$3.99/MMBtu
Total	$ 2.3	$ 2.2			

We believe forward commodity prices are the most significant unobservable inputs in determining our Level 3 recurring fair value measurements at September 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.

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 September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
NGL Pipelines & Services	$ 0.3	$ 8.3	$ 10.0	$ 16.3
Onshore Natural Gas Pipelines & Services	--	29.2	--	29.2
Onshore Crude Oil Pipelines & Services	--	--	16.6	6.2
Offshore Pipelines & Services	13.2	4.0	13.2	4.0
Petrochemical & Refined Products Services	1.7	1.6	13.5	1.9
Total	$ 15.2	$ 43.1	$ 53.3	$ 57.6

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

During the nine months ended September 30, 2013, we recorded $53.3 million of non-cash asset impairment charges primarily due to the abandonment of assets classified as property, plant and equipment. The following table summarizes our non-recurring fair value measurements for the nine months ended September 30, 2013:

		Fair Value Measurements Using			
	Carrying Value at September 30, 2013	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Non-Cash Impairment Loss
Impairment of long-lived assets disposed of other than by sale (1)	$ --	$ --	$ --	$ --	$ 43.3
Impairment of long-lived assets held and used	6.1	--	--	6.1	4.2
Impairment of long-lived assets to be disposed of by sale	11.7	11.7	--	--	5.8
Total					$ 53.3

(1) Our non-cash asset impairment charges for the nine months ended September 30, 2013 primarily represent the abandonment of crude oil and natural gas pipeline segments in Texas, Oklahoma and the Gulf of Mexico, certain refined products terminal assets in Texas, and an NGL storage cavern in Arizona.

During the nine months ended September 30, 2012, we recorded $57.6 million of non-cash asset impairment charges primarily due to the abandonment of assets classified as property, plant and equipment. The following table summarizes our non-recurring fair value measurements for the nine months ended September 30, 2012:

		Fair Value Measurements Using			
	Carrying Value at September 30, 2012	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Non-Cash Impairment Loss
Impairment of long-lived assets disposed of other than by sale (1)	$ --	$ --	$ --	$ --	$ 50.7
Impairment of long-lived assets held and used	2.2	--	--	2.2	2.6
Impairment of long-lived assets to be disposed of by sale	--	--	--	--	4.3
Total					$ 57.6

(1) Our non-cash asset impairment charges for the nine months ended September 30, 2012 primarily represent the abandonment of crude oil and natural gas pipeline segments in Texas and the Gulf of Mexico.

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 fixed-rate debt obligations was $18.42 billion at September 30, 2013 and December 31, 2012. The aggregate carrying value of these debt obligations was $17.43 billion and $16.18 billion at September 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:

	September 30, 2013	December 31, 2012
NGLs	$ 1,085.8	$ 594.3
Petrochemicals and refined products	448.2	304.5
Crude oil	254.8	119.4
Natural gas	73.6	70.2
Total	$ 1,862.4	$ 1,088.4

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 September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
Cost of sales (1)	$ 10,371.3	$ 8,794.0	$ 29,522.1	$ 26,655.0
Lower of cost or market adjustments	4.5	2.2	14.9	16.1

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

Note 6. Property, Plant and Equipment

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	September 30, 2013	December 31, 2012
Plants, pipelines and facilities (1)	3-45 (6)	$ 26,878.4	$ 25,382.4
Underground and other storage facilities (2)	5-40 (7)	1,980.5	1,826.3
Platforms and facilities (3)	20-31	659.6	635.2
Transportation equipment (4)	3-10	133.1	136.2
Marine vessels (5)	15-30	721.5	695.0
Land		176.1	167.2
Construction in progress		2,705.8	2,113.1
Total		33,255.0	30,955.4
Less accumulated depreciation		6,801.1	6,109.0
Property, plant and equipment, net		$ 26,453.9	$ 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 September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
Depreciation expense (1)	$ 253.4	$ 228.3	$ 749.6	$ 662.3
Capitalized interest (2)	27.8	26.3	95.1	86.4

(1) Depreciation expense is a component of "Costs and expenses" as presented on our Unaudited Condensed Statements of Consolidated Operations.
(2) We capitalize interest costs incurred on funds used to construct property, plant and equipment while the asset is in its construction phase. 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 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 nine months ended September 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. See Note 16 for additional information regarding our asset sales.

Asset Retirement Obligations

Property, plant and equipment at September 30, 2013 and December 31, 2012 includes $39.3 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 nine months ended September 30, 2013:

ARO liability balance, December 31, 2012	$ 105.2
Liabilities incurred	0.1
Liabilities settled	(10.4)
Revisions in estimated cash flows	(2.2)
Accretion expense	4.6
ARO liability balance, September 30, 2013	$ 97.3

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

Remainder of 2013	2014	2015	2016	2017
$ 1.5	$ 6.3	$ 6.7	$ 7.1	$ 7.7

Certain of our unconsolidated affiliates have AROs recorded at September 30, 2013 and December 31, 2012 relating to contractual agreements and regulatory requirements. These amounts are immaterial to our 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 September 30, 2013	September 30, 2013	December 31, 2012
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C.	13.1%	$ 28.1	$ 29.6
K/D/S Promix, L.L.C.	50%	44.4	46.9
Baton Rouge Fractionators LLC	32.2%	19.3	20.2
Skelly-Belvieu Pipeline Company, L.L.C.	50%	40.5	38.2
Texas Express Pipeline LLC (1)	35%	328.5	144.4
Texas Express Gathering LLC (1)	45%	34.6	20.9
Front Range Pipeline LLC	33.3%	111.8	24.4
Onshore Natural Gas Pipelines & Services:			
White River Hub, LLC	50%	24.3	24.9
Onshore Crude Oil Pipelines & Services:			
Seaway Crude Pipeline Company LLC	50%	677.2	341.4
Eagle Ford Pipeline LLC (2)	50%	212.4	152.4
Offshore Pipelines & Services:			
Poseidon Oil Pipeline Company, L.L.C. ("Poseidon")	36%	43.4	47.3
Cameron Highway Oil Pipeline Company	50%	209.9	220.0
Deepwater Gateway, L.L.C.	50%	86.2	90.0
Neptune Pipeline Company, L.L.C.	25.7%	43.7	46.8
Southeast Keathley Canyon Pipeline Company L.L.C.	50%	157.2	74.9
Petrochemical & Refined Products Services:			
Baton Rouge Propylene Concentrator, LLC	30%	7.8	8.5
Centennial Pipeline LLC ("Centennial")	50%	62.3	60.8
Other (3)	Various	2.9	3.0
Total		$ 2,134.5	$ 1,394.6

(1) Planned principal operations commenced in November 2013.
(2) Planned principal operations commenced in July 2013.
(3) 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 September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
NGL Pipelines & Services	$ 4.1	$ 3.0	$ 11.8	$ 12.0
Onshore Natural Gas Pipelines & Services	1.0	0.9	2.9	3.5
Onshore Crude Oil Pipelines & Services	34.3	16.5	101.0	20.6
Offshore Pipelines & Services	9.8	6.8	24.9	17.8
Petrochemical & Refined Products Services	(5.2)	(6.2)	(14.5)	(14.1)
Other Investments	--	--	--	2.4
Total	$ 44.0	$ 21.0	$ 126.1	$ 42.2

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

	September 30, 2013	December 31, 2012
NGL Pipelines & Services	$ 28.0	$ 28.9
Onshore Crude Oil Pipelines & Services	18.0	18.5
Offshore Pipelines & Services	12.6	13.6
Petrochemical & Refined Products Services	2.6	2.7
Total	$ 61.2	$ 63.7

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
NGL Pipelines & Services	$ 0.3	$ 0.2	$ 0.9	$ 0.7
Onshore Crude Oil Pipelines & Services	0.1	0.2	0.5	0.5
Offshore Pipelines & Services	0.3	0.3	1.0	0.9
Petrochemical & Refined Products Services	0.1	--	0.1	0.1
Other Investments	--	--	--	0.3
Total	$ 0.8	$ 0.7	$ 2.5	$ 2.5

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 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.

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 September 30, 2013.

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Note 8. Intangible Assets and Goodwill

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

	September 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	$ (161.3)	$ 179.5	$ 340.8	$ (147.6)	$ 193.2
Contract-based intangibles	281.3	(166.9)	114.4	284.6	(157.2)	127.4
Segment total	622.1	(328.2)	293.9	625.4	(304.8)	320.6
Onshore Natural Gas Pipelines & Services:						
Customer relationship intangibles	1,163.6	(273.8)	889.8	1,163.6	(250.0)	913.6
Contract-based intangibles	466.1	(326.0)	140.1	466.1	(311.8)	154.3
Segment total	1,629.7	(599.8)	1,029.9	1,629.7	(561.8)	1,067.9
Onshore Crude Oil Pipelines & Services:						
Customer relationship intangibles	10.7	(5.9)	4.8	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	(6.2)	4.9	11.1	(5.2)	5.9
Offshore Pipelines & Services:						
Customer relationship intangibles	203.9	(147.3)	56.6	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	(147.7)	57.4	205.1	(138.9)	66.2
Petrochemical & Refined Products Services:						
Customer relationship intangibles	104.3	(37.1)	67.2	104.3	(33.4)	70.9
Contract-based intangibles	39.9	(5.6)	34.3	41.2	(5.9)	35.3
Segment total	144.2	(42.7)	101.5	145.5	(39.3)	106.2
Total all segments	$ 2,612.2	$ (1,124.6)	$ 1,487.6	$ 2,616.8	$ (1,050.0)	$ 1,566.8

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
NGL Pipelines & Services	$ 8.6	$ 10.1	$ 27.7	$ 29.9
Onshore Natural Gas Pipelines & Services	13.3	16.8	38.0	48.4
Onshore Crude Oil Pipelines & Services	0.3	0.2	1.0	0.5
Offshore Pipelines & Services	2.9	3.1	8.8	8.3
Petrochemical & Refined Products Services	1.5	2.1	4.7	8.8
Total	$ 26.6	$ 32.3	$ 80.2	$ 95.9

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
$ 25.5	$ 96.3	$ 90.4	$ 92.1	$ 96.1

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 nine months ended September 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 September 30, 2013 (1)	$ 341.2	$ 296.3	$ 305.1	$ 82.1	$ 1,055.3	$ 2,080.0

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

Note 9. Debt Obligations

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

	September 30, 2013	December 31, 2012
EPO senior debt obligations:		
Commercial Paper Notes, fixed-rates (1)	$ 550.0	$ 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	100.0	--
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	16,000.0	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	17,532.7	16,179.3
Other, non-principal amounts:		
Change in fair value of debt hedged in fair value hedging relationship (2)	28.9	39.3
Unamortized discounts, net of premiums	(41.9)	(38.0)
Other	11.8	21.2
Total other, non-principal amounts	(1.2)	22.5
Less current maturities of debt (3)	(1,049.9)	(1,546.6)
Total long-term debt	$ 16,481.6	$ 14,655.2

(1) Principal amounts outstanding at September 30, 2013 have fixed-rates ranging from 0.26% and 0.29% and are due in October 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. 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 at September 30, 2013 for the periods indicated:

		Scheduled Maturities of Debt					
	Total	Remainder of 2013	2014	2015	2016	2017	After 2017
Commercial Paper Notes	$ 550.0	$ 550.0	$ --	$ --	$ --	$ --	$ --
Multi-Year Revolving Credit Facility	100.0	--	--	--	--	--	100.0
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	$ 17,532.7	$ 550.0	$ 1,150.0	$ 1,300.0	$ 750.0	$ 800.0	$ 12,982.7

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. 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 September 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 September 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 nine months ended September 30, 2013:

	Range of Interest Rates Paid	Weighted-Average Interest Rate Paid
EPO $3.5 Billion Multi-Year Revolving Credit Facility	1.15% to 1.51%	1.31%

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 nine months ended September 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	7,284,807	--	7,284,807
Common units issued in connection with our DRIP and EUPP	3,760,154	--	3,760,154
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	1,846,198	(1,846,198)	--
Conversion and reclassification of Class B units to common units	4,520,431	--	4,520,431
Restricted common unit awards issued	--	1,769,076	1,769,076
Forfeiture of restricted common unit awards	--	(159,832)	(159,832)
Acquisition and cancellation of treasury units in connection with the vesting of equity-based awards	(618,317)	--	(618,317)
Number of units outstanding at September 30, 2013	921,114,006	3,656,532	924,770,538

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). See Note 18 for information regarding a November 2013 public offering of our common units.

On October 1, 2013, we filed a registration statement with the SEC covering the issuance of up to $1.25 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. The new registration statement was declared effective on October 15, 2013 and replaced our prior registration statement with respect to the at-the-market program, which was filed with the SEC in March 2012 and covered the issuance of up to $1.0 billion of our common units. Immediately prior to the effectiveness of the new registration statement, we had the capacity to issue additional common units under the at-the-market program up to an aggregate sales price of $334.2 million (after giving effect to sales of common units previously made under the program). Following the effectiveness of the new registration statement, we now have the capacity to issue additional common units under our at-the-market program up to an aggregate sales price of $1.25 billion.

During the nine months ended September 30, 2013, we sold 7,624,689 common units under our at-the-market program for aggregate gross proceeds of $460.4 million. After taking into account applicable costs, these transactions resulted in net proceeds of $456.3 million, of which $435.5 million was received and 7,284,807 common units issued and outstanding as of September 30, 2013. The remaining 339,882 common units sold under the program during the nine months ended September 30, 2013 were issued in October 2013 upon closing of the sales of such common units and receipt of the $20.8 million balance of proceeds. After taking into account the aggregate sale price of common units sold under our at-the-market program through September 30, 2013 and the new registration statement that was declared effective on October 15, 2013, we have the capacity to issue additional common units under this program up to an aggregate sales price of $1.25 billion.

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 nine months ended September 30, 2012, we issued 1,905,797 common units, which generated net proceeds of $93.6 million. We issued a total of 3,649,323 common units under our DRIP during the nine months ended September 30, 2013, which generated net proceeds of $206.0 million. After taking into account the number of common units issued under the DRIP through September 30, 2013, we have the capacity to issue an additional 19,843,969 common units under this plan.

In January 2013, affiliates of privately held EPCO, which own our general partner and approximately 36.8% of our limited partner interests at September 30, 2013, expressed their willingness to purchase at least $100 million of our common units during 2013 through our DRIP. During the nine months ended September 30, 2013, these EPCO affiliates reinvested $75.0 million, resulting in the issuance of 1,331,774 common units under our DRIP (this amount being a component of the total common units issued under the DRIP during the nine months ended September 30, 2013). On November 7, 2013, these affiliates reinvested an additional $25.0 million under the DRIP, which increased their total investment for 2013 to $100.0 million.

In addition to the DRIP, we have registration statements on file with the SEC authorizing the issuance of our common units in connection with an employee unit purchase plan (or "EUPP"). In September 2013, our unitholders approved the amendment and restatement of the EUPP. As a result, the maximum number of common units issuable under the EUPP increased from 440,879 common units to 4,000,000 common units. In addition, the term of the EUPP was extended to September 2023. During the nine months ended September 30, 2012, we issued 102,469 common units, which generated net proceeds of $5.4 million. We issued 110,831 common units under our EUPP during the nine months ended September 30, 2013, which generated net proceeds of $6.6 million. After taking into account the number of common units issued under the EUPP through September 30, 2013, we may issue an additional 3,744,326 common units under the amended and restated EUPP.

The net cash proceeds we received from the issuance of common units during the nine months ended September 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 1,846,198 restricted common unit awards granted to employees of EPCO vested and converted to common units during the nine months ended September 30, 2013. Of this amount, 618,317 were sold back to us by employees to cover related withholding tax requirements. The total cost of these treasury unit purchases was approximately $36.1 million. We cancelled such treasury units immediately upon acquisition. See Note 3 for additional information regarding our equity-based awards.

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.

Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss primarily reflects the effective portion of any gains or losses on derivative instruments designated and qualified as cash flow hedges. Amounts related to cash flow hedges recorded in accumulated other comprehensive 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 loss in accumulated other comprehensive loss is immediately reclassified into earnings.

The following table presents reclassifications out of accumulated other comprehensive loss into net income during the periods indicated:

	Location	For the Three Months Ended September 30, 2013	For the Nine Months Ended September 30, 2013
Losses (gains) on cash flow hedges:			
Interest rate derivatives	Interest expense	$ 7.7	$ 21.4
Commodity derivatives	Revenue	14.6	15.1
Commodity derivatives	Operating costs and expenses	--	(0.4)
Total		$ 22.3	$ 36.1

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 at our complex in Mont Belvieu, Texas. 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.

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
3rd Quarter	$ 0.69	10/31/13	11/07/13

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.

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.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
Revenues	$ 12,093.3	$ 10,468.7	$ 34,625.7	$ 31,511.0
Less: Operating costs and expenses	(11,273.5)	(9,659.8)	(32,061.1)	(29,136.5)
Add: Equity in income of unconsolidated affiliates	44.0	21.0	126.1	42.2
Amounts included in operating costs and expenses:				
Depreciation, amortization and accretion	285.2	269.2	851.7	785.1
Non-cash asset impairment charges	15.2	43.1	53.3	57.6
Gains attributable to asset sales and insurance recoveries	(10.2)	(2.6)	(68.4)	(34.1)
Total segment gross operating margin	$ 1,154.0	$ 1,139.6	$ 3,527.3	$ 3,225.3

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 September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
Total segment gross operating margin	$ 1,154.0	$ 1,139.6	$ 3,527.3	$ 3,225.3
Adjustments to reconcile total segment gross operating margin to operating income:				
Amounts included in operating costs and expenses:				
Depreciation, amortization and accretion	(285.2)	(269.2)	(851.7)	(785.1)
Non-cash asset impairment charges	(15.2)	(43.1)	(53.3)	(57.6)
Gains attributable to asset sales and insurance recoveries	10.2	2.6	68.4	34.1
General and administrative costs	(43.9)	(41.4)	(138.9)	(130.2)
Operating income	819.9	788.5	2,551.8	2,286.5
Other expense, net	(207.7)	(198.2)	(604.2)	(499.4)
Income before income taxes	$ 612.2	$ 590.3	$ 1,947.6	$ 1,787.1

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

	Reportable Business Segments							
	NGL Pipelines & Services	Onshore Natural Gas Pipelines & Services	Onshore Crude Oil Pipelines & Services	Offshore Pipelines & Services	Petrochemical & Refined Products Services	Other Investments	Adjustments and Eliminations	Consolidated Total
Revenues from third parties:								
Three months ended September 30, 2013	$ 4,230.6	$ 831.4	$ 5,435.4	$ 38.2	$ 1,550.0	$ --	$ --	$ 12,085.6
Three months ended September 30, 2012	3,389.6	843.3	4,505.1	43.2	1,680.0	--	--	10,461.2
Nine months ended September 30, 2013	11,686.0	2,658.6	15,358.1	118.0	4,784.7	--	--	34,605.4
Nine months ended September 30, 2012	11,071.6	2,349.1	13,167.4	145.1	4,713.9	--	--	31,447.1
Revenues from related parties:								
Three months ended September 30, 2013	0.1	4.1	2.1	1.4	--	--	--	7.7
Three months ended September 30, 2012	2.2	3.2	0.1	2.0	--	--	--	7.5
Nine months ended September 30, 2013	0.6	12.1	2.1	5.5	--	--	--	20.3
Nine months ended September 30, 2012	7.2	51.4	0.1	5.2	--	--	--	63.9
Intersegment and intrasegment revenues:								
Three months ended September 30, 2013	2,542.3	215.6	3,591.3	1.8	384.4	--	(6,735.4)	--
Three months ended September 30, 2012	2,301.6	211.4	1,509.2	--	478.8	--	(4,501.0)	--
Nine months ended September 30, 2013	7,631.7	726.7	8,333.0	8.0	1,200.7	--	(17,900.1)	--
Nine months ended September 30, 2012	7,396.3	614.1	4,975.6	5.0	1,357.4	--	(14,348.4)	--
Total revenues:								
Three months ended September 30, 2013	6,773.0	1,051.1	9,028.8	41.4	1,934.4	--	(6,735.4)	12,093.3
Three months ended September 30, 2012	5,693.4	1,057.9	6,014.4	45.2	2,158.8	--	(4,501.0)	10,468.7
Nine months ended September 30, 2013	19,318.3	3,397.4	23,693.2	131.5	5,985.4	--	(17,900.1)	34,625.7
Nine months ended September 30, 2012	18,475.1	3,014.6	18,143.1	155.3	6,071.3	--	(14,348.4)	31,511.0
Equity in income (loss) of unconsolidated affiliates:								
Three months ended September 30, 2013	4.1	1.0	34.3	9.8	(5.2)	--	--	44.0
Three months ended September 30, 2012	3.0	0.9	16.5	6.8	(6.2)	--	--	21.0
Nine months ended September 30, 2013	11.8	2.9	101.0	24.9	(14.5)	--	--	126.1
Nine months ended September 30, 2012	12.0	3.5	20.6	17.8	(14.1)	2.4	--	42.2
Gross operating margin:								
Three months ended September 30, 2013	639.6	213.4	146.0	37.9	117.1	--	--	1,154.0
Three months ended September 30, 2012	615.8	183.5	117.6	40.6	182.1	--	--	1,139.6
Nine months ended September 30, 2013	1,777.0	601.9	579.6	118.1	450.7	--	--	3,527.3
Nine months ended September 30, 2012	1,836.5	565.5	252.7	131.0	437.2	2.4	--	3,225.3
Property, plant and equipment, net: (see Note 6)								
At September 30, 2013	9,529.0	8,892.5	1,455.0	1,244.5	2,627.1	--	2,705.8	26,453.9
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 September 30, 2013	607.2	24.3	889.6	540.4	73.0	--	--	2,134.5
At December 31, 2012	324.6	24.9	493.8	479.0	72.3	--	--	1,394.6
Intangible assets, net: (see Note 8)								
At September 30, 2013	293.9	1,029.9	4.9	57.4	101.5	--	--	1,487.6
At December 31, 2012	320.6	1,067.9	5.9	66.2	106.2	--	--	1,566.8
Goodwill: (see Note 8)								
At September 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 September 30, 2013	10,771.3	10,243.0	2,654.6	1,924.4	3,856.9	--	2,705.8	32,156.0
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

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
NGL Pipelines & Services:				
Sales of NGLs and related products	$ 3,929.8	$ 3,151.9	$ 10,831.3	$ 10,401.1
Midstream asset services	300.9	239.9	855.3	677.7
Total	4,230.7	3,391.8	11,686.6	11,078.8
Onshore Natural Gas Pipelines & Services:				
Sales of natural gas	590.7	608.2	1,954.1	1,691.6
Midstream asset services	244.8	238.3	716.6	708.9
Total	835.5	846.5	2,670.7	2,400.5
Onshore Crude Oil Pipelines & Services:				
Sales of crude oil	5,359.7	4,471.8	15,159.9	13,093.4
Midstream asset services	77.8	33.4	200.3	74.1
Total	5,437.5	4,505.2	15,360.2	13,167.5
Offshore Pipelines & Services:				
Sales of natural gas	0.1	0.2	0.3	0.3
Sales of crude oil	1.5	3.1	3.7	4.5
Midstream asset services	38.0	41.9	119.5	145.5
Total	39.6	45.2	123.5	150.3
Petrochemical & Refined Products Services:				
Sales of petrochemicals and refined products	1,390.1	1,498.9	4,271.5	4,166.9
Midstream asset services	159.9	181.1	513.2	547.0
Total	1,550.0	1,680.0	4,784.7	4,713.9
Total consolidated revenues	$ 12,093.3	$ 10,468.7	$ 34,625.7	$ 31,511.0
Consolidated costs and expenses				
Operating costs and expenses:				
Cost of sales	$ 10,371.3	$ 8,794.0	$ 29,522.1	$ 26,655.0
Other operating costs and expenses (1)	612.0	556.1	1,702.4	1,672.9
Depreciation, amortization and accretion	285.2	269.2	851.7	785.1
Gains attributable to asset sales and insurance recoveries	(10.2)	(2.6)	(68.4)	(34.1)
Non-cash asset impairment charges	15.2	43.1	53.3	57.6
General and administrative costs	43.9	41.4	138.9	130.2
Total consolidated costs and expenses	$ 11,317.4	$ 9,701.2	$ 32,200.0	$ 29,266.7

(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.

Note 12. Related Party Transactions

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
Revenues – related parties:				
Unconsolidated affiliates	$ 7.7	$ 7.5	$ 20.3	$ 63.9
Costs and expenses – related parties:				
EPCO and affiliates	$ 218.8	$ 210.8	$ 654.4	$ 616.9
Unconsolidated affiliates	25.9	15.0	86.5	27.3
Total	$ 244.7	$ 225.8	$ 740.9	$ 644.2

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

	September 30, 2013	December 31, 2012
Accounts receivable – related parties:		
Unconsolidated affiliates	$ 12.8	$ 2.5
Accounts payable – related parties:		
EPCO and affiliates	$ 86.2	$ 102.4
Unconsolidated affiliates	10.3	24.7
Total	$ 96.5	$ 127.1

We believe that the terms and provisions of our related party agreements are fair to us; however, such agreements and transactions may not be as favorable to us as we could have obtained from unaffiliated third parties.

Relationship with EPCO and Affiliates

We have an extensive and ongoing relationship with EPCO and its privately held affiliates (including Enterprise GP, our general partner), which are not a part of our consolidated group of companies. At September 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
340,462,655	36.8%

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 nine months ended September 30, 2013 and 2012, we paid EPCO and its privately held affiliates cash distributions totaling $601.2 million and $557.7 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.

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 September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
Operating costs and expenses	$ 190.5	$ 185.3	$ 564.7	$ 541.6
General and administrative expenses	28.3	25.5	89.7	75.3
Total costs and expenses	$ 218.8	$ 210.8	$ 654.4	$ 616.9

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 September 30		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
BASIC EARNINGS PER UNIT				
Numerator:				
Net income attributable to limited partners	$ 592.0	$ 586.8	$ 1,898.0	$ 1,804.4
Denominator:				
Weighted-average number of distribution-bearing common units outstanding	896.3	859.3	889.1	857.9
Basic earnings per unit:				
Net income attributable to limited partners	$ 0.66	$ 0.68	$ 2.13	$ 2.10
DILUTED EARNINGS PER UNIT				
Numerator:				
Net income attributable to limited partners	$ 592.0	$ 586.8	$ 1,898.0	$ 1,804.4
Denominator:				
Weighted-average number of units outstanding:				
Distribution-bearing common units	896.3	859.3	889.1	857.9
Class B units	1.9	4.5	3.6	4.5
Designated Units	23.7	26.1	23.7	26.1
Incremental option units	1.1	1.5	1.2	1.5
Total	923.0	891.4	917.6	890.0
Diluted earnings per unit:				
Net income attributable to limited partners	$ 0.64	$ 0.66	$ 2.07	$ 2.03

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 September 30, 2013 and December 31, 2012, our accruals for litigation contingencies were $5.7 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 $19.6 million and $26.0 million during the third quarters of 2013 and 2012, respectively. For the nine months ended September 30, 2013 and 2012, consolidated lease and rental expense was $64.9 million and $71.1 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 September 30, 2013, our contingent claims against such parties were $38.9 million and claims against us were $44.1 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.

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 nine months ended September 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 nine months ended September 30, 2012, we collected $2.3 million and $30.0 million, respectively, of such proceeds. We did not receive any proceeds related to these claims during the third 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 nine months ended September 30, 2013 includes $8.8 million of gains related to these insurance recoveries. Operating income for the three and nine months ended September 30, 2012 includes $2.3 million and $30.0 million, respectively, 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 Nine Months Ended September 30, 2013	For the Nine Months Ended September 30, 2012
Decrease (increase) in:		
Accounts receivable – trade	$ (1,130.0)	$ 121.7
Accounts receivable – related parties	(9.6)	27.5
Inventories	(674.2)	(229.2)
Prepaid and other current assets	(31.5)	(11.3)
Other assets	3.2	(54.3)
Increase (decrease) in:		
Accounts payable – trade	114.3	36.2
Accounts payable – related parties	(30.4)	(98.9)
Accrued product payables	1,358.1	(609.4)
Accrued interest	(132.6)	(100.0)
Other current liabilities	29.3	26.9
Other liabilities	(10.5)	(19.4)
Net effect of changes in operating accounts	$ (513.9)	$ (910.2)

We incurred liabilities for construction in progress that had not been paid at September 30, 2013 and December 31, 2012 of $378.4 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.

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

	For the Nine Months Ended September 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	--
Sales of pipeline line fill	65.0	23.7
Sale of lubrication oil and specialty chemical distribution assets	35.3	--
Sale of chemical trucking assets	29.5	--
Sales of marine transportation assets	16.5	2.4
Insurance recoveries attributable to West Storage claims (see Note 15)	8.8	30.0
Other cash proceeds	14.3	16.0
Total	$ 256.3	$ 1,167.4

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

	For the Nine Months Ended September 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)	52.5	--
Net gains attributable to other asset sales	7.1	4.1
Gains attributable to insurance recoveries (see Note 15)	8.8	30.0
Total	$ 68.4	$ 102.9

(1) This amount is a component of "Other income" as presented on our Unaudited Condensed Statements of Consolidated Operations. All other amounts presented in the table 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.
Unaudited Condensed Consolidating Balance Sheet
September 30, 2013

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
ASSETS							
Current assets:							
Cash and cash equivalents and restricted cash	$ 36.6	$ 31.9	$ (23.0)	$ 45.5	$ --	$ --	$ 45.5
Accounts receivable – trade, net	1,846.8	3,624.8	(2.5)	5,469.1	--	--	5,469.1
Accounts receivable – related parties	317.4	1,452.9	(1,757.1)	13.2	--	(0.4)	12.8
Inventories	1,526.9	336.6	(1.1)	1,862.4	--	--	1,862.4
Prepaid and other current assets	165.2	225.1	(9.4)	380.9	0.2	--	381.1
Total current assets	3,892.9	5,671.3	(1,793.1)	7,771.1	0.2	(0.4)	7,770.9
Property, plant and equipment, net	1,863.3	24,588.6	2.0	26,453.9	--	--	26,453.9
Investments in unconsolidated affiliates	30,113.0	2,598.8	(30,577.3)	2,134.5	14,472.9	(14,472.9)	2,134.5
Intangible assets, net	77.3	1,410.3	--	1,487.6	--	--	1,487.6
Goodwill	458.9	1,621.1	--	2,080.0	--	--	2,080.0
Other assets	128.7	73.2	(3.9)	198.0	0.1	--	198.1
Total assets	$ 36,534.1	$ 35,963.3	$ (32,372.3)	$ 40,125.1	$ 14,473.2	$ (14,473.3)	$ 40,125.0
LIABILITIES AND EQUITY							
Current liabilities:							
Current maturities of debt	$ 1,049.9	$ --	$ --	$ 1,049.9	$ --	$ --	$ 1,049.9
Accounts payable – trade	353.1	710.1	(23.0)	1,040.2	0.1	--	1,040.3
Accounts payable – related parties	1,588.6	261.7	(1,754.5)	95.8	1.0	(0.3)	96.5
Accrued product payables	2,364.1	3,614.9	(6.2)	5,972.8	--	--	5,972.8
Accrued interest	167.9	0.3	--	168.2	--	--	168.2
Other current liabilities	90.7	315.8	(9.3)	397.2	--	(1.1)	396.1
Total current liabilities	5,614.3	4,902.8	(1,793.0)	8,724.1	1.1	(1.4)	8,723.8
Long-term debt	16,466.6	15.0	--	16,481.6	--	--	16,481.6
Deferred tax liabilities	3.6	53.3	(3.9)	53.0	--	2.0	55.0
Other long-term liabilities	11.3	171.2	(0.1)	182.4	--	--	182.4
Commitments and contingencies							
Equity:							
Partners' and other owners' equity	14,438.3	30,748.3	(30,739.0)	14,447.6	14,472.1	(14,447.6)	14,472.1
Noncontrolling interests	--	72.7	163.7	236.4	--	(26.3)	210.1
Total equity	14,438.3	30,821.0	(30,575.3)	14,684.0	14,472.1	(14,473.9)	14,682.2
Total liabilities and equity	$ 36,534.1	$ 35,963.3	$ (32,372.3)	$ 40,125.1	$ 14,473.2	$ (14,473.3)	$ 40,125.0

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						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
ASSETS							
Current assets:							
Cash and cash equivalents and restricted cash	$ 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 September 30, 2013

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Revenues	$ 7,070.3	$ 8,588.4	$ (3,565.4)	$ 12,093.3	$ --	$ --	$ 12,093.3
Costs and expenses:							
Operating costs and expenses	6,858.0	7,980.9	(3,565.4)	11,273.5	--	--	11,273.5
General and administrative costs	7.6	36.0	--	43.6	0.3	--	43.9
Total costs and expenses	6,865.6	8,016.9	(3,565.4)	11,317.1	0.3	--	11,317.4
Equity in income of unconsolidated affiliates	577.2	47.8	(581.0)	44.0	592.3	(592.3)	44.0
Operating income	781.9	619.3	(581.0)	820.2	592.0	(592.3)	819.9
Other income (expense):							
Interest expense	(208.0)	(0.3)	--	(208.3)	--	--	(208.3)
Other, net	0.1	0.5	--	0.6	--	--	0.6
Total other expense, net	(207.9)	0.2	--	(207.7)	--	--	(207.7)
Income before income taxes	574.0	619.5	(581.0)	612.5	592.0	(592.3)	612.2
Benefit from (provision for) income taxes	17.7	(36.8)	--	(19.1)	--	(0.3)	(19.4)
Net income	591.7	582.7	(581.0)	593.4	592.0	(592.6)	592.8
Net income attributable to noncontrolling interests	--	(0.2)	(1.6)	(1.8)	--	1.0	(0.8)
Net income attributable to entity	$ 591.7	$ 582.5	$ (582.6)	$ 591.6	$ 592.0	$ (591.6)	$ 592.0

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

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Revenues	$ 6,392.6	$ 7,072.5	$ (2,996.4)	$ 10,468.7	$ --	$ --	$ 10,468.7
Costs and expenses:							
Operating costs and expenses	6,192.8	6,464.8	(2,997.8)	9,659.8	--	--	9,659.8
General and administrative costs	(4.4)	45.6	--	41.2	0.2	--	41.4
Total costs and expenses	6,188.4	6,510.4	(2,997.8)	9,701.0	0.2	--	9,701.2
Equity in income of unconsolidated affiliates	581.4	25.7	(586.1)	21.0	587.0	(587.0)	21.0
Operating income	785.6	587.8	(584.7)	788.7	586.8	(587.0)	788.5
Other income (expense):							
Interest expense	(199.0)	(0.7)	--	(199.7)	--	--	(199.7)
Other, net	--	1.5	--	1.5	--	--	1.5
Total other expense, net	(199.0)	0.8	--	(198.2)	--	--	(198.2)
Income before income taxes	586.6	588.6	(584.7)	590.5	586.8	(587.0)	590.3
Provision for income taxes	(1.4)	(0.8)	--	(2.2)	--	(0.2)	(2.4)
Net income	585.2	587.8	(584.7)	588.3	586.8	(587.2)	587.9
Net income attributable to noncontrolling interests	--	(0.4)	(1.2)	(1.6)	--	0.5	(1.1)
Net income attributable to entity	$ 585.2	$ 587.4	$ (585.9)	$ 586.7	$ 586.8	$ (586.7)	$ 586.8

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
Nine Months Ended September 30, 2013

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Revenues	$ 20,916.8	$ 24,044.5	$ (10,335.6)	$ 34,625.7	$ --	$ --	$ 34,625.7
Costs and expenses:							
Operating costs and expenses	20,328.5	22,068.2	(10,335.6)	32,061.1	--	--	32,061.1
General and administrative costs	19.7	118.0	--	137.7	1.2	--	138.9
Total costs and expenses	20,348.2	22,186.2	(10,335.6)	32,198.8	1.2	--	32,200.0
Equity in income of unconsolidated affiliates	1,936.2	141.9	(1,952.0)	126.1	1,899.2	(1,899.2)	126.1
Operating income	2,504.8	2,000.2	(1,952.0)	2,553.0	1,898.0	(1,899.2)	2,551.8
Other income (expense):							
Interest expense	(603.0)	(1.4)	--	(604.4)	--	--	(604.4)
Other, net	0.3	(0.1)	--	0.2	--	--	0.2
Total other expense, net	(602.7)	(1.5)	--	(604.2)	--	--	(604.2)
Income before income taxes	1,902.1	1,998.7	(1,952.0)	1,948.8	1,898.0	(1,899.2)	1,947.6
Provision for income taxes	(4.9)	(40.7)	--	(45.6)	--	(0.6)	(46.2)
Net income	1,897.2	1,958.0	(1,952.0)	1,903.2	1,898.0	(1,899.8)	1,901.4
Net income attributable to noncontrolling interests	--	(1.1)	(4.9)	(6.0)	--	2.6	(3.4)
Net income attributable to entity	$ 1,897.2	$ 1,956.9	$ (1,956.9)	$ 1,897.2	$ 1,898.0	$ (1,897.2)	$ 1,898.0

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

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Revenues	$ 20,066.0	$ 20,927.0	$ (9,482.0)	$ 31,511.0	$ --	$ --	$ 31,511.0
Costs and expenses:							
Operating costs and expenses	19,467.0	19,151.4	(9,481.9)	29,136.5	--	--	29,136.5
General and administrative costs	20.1	108.9	--	129.0	1.2	--	130.2
Total costs and expenses	19,487.1	19,260.3	(9,481.9)	29,265.5	1.2	--	29,266.7
Equity in income of unconsolidated affiliates	1,774.7	53.1	(1,785.6)	42.2	1,805.6	(1,805.6)	42.2
Operating income	2,353.6	1,719.8	(1,785.7)	2,287.7	1,804.4	(1,805.6)	2,286.5
Other income (expense):							
Interest expense	(570.3)	(2.5)	--	(572.8)	--	--	(572.8)
Other, net	0.1	73.3	--	73.4	--	--	73.4
Total other expense, net	(570.2)	70.8	--	(499.4)	--	--	(499.4)
Income before income taxes	1,783.4	1,790.6	(1,785.7)	1,788.3	1,804.4	(1,805.6)	1,787.1
Benefit from income taxes	21.0	2.9	-	23.9	--	(0.4)	23.5
Net income	1,804.4	1,793.5	(1,785.7)	1,812.2	1,804.4	(1,806.0)	1,810.6
Net income attributable to noncontrolling interests	--	(4.6)	(3.2)	(7.8)	--	1.6	(6.2)
Net income attributable to entity	$ 1,804.4	$ 1,788.9	$ (1,788.9)	$ 1,804.4	$ 1,804.4	$ (1,804.4)	$ 1,804.4

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

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Comprehensive income	$ 583.4	$ 604.7	$ (580.9)	$ 607.2	$ 605.7	$ (606.4)	$ 606.5
Comprehensive income attributable to noncontrolling interests	--	(0.2)	(1.6)	(1.8)	--	1.0	(0.8)
Comprehensive income attributable to entity	$ 583.4	$ 604.5	$ (582.5)	$ 605.4	$ 605.7	$ (605.4)	$ 605.7

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

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Comprehensive income	$ 559.8	$ 543.5	$ (584.7)	$ 518.6	$ 517.2	$ (517.5)	$ 518.3
Comprehensive income attributable to noncontrolling interests	--	(0.4)	(1.2)	(1.6)	--	0.5	(1.1)
Comprehensive income attributable to entity	$ 559.8	$ 543.1	$ (585.9)	$ 517.0	$ 517.2	$ (517.0)	$ 517.2

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

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Comprehensive income	$ 1,911.5	$ 1,964.7	$ (1,951.9)	$ 1,924.3	$ 1,919.1	$ (1,920.9)	$ 1,922.5
Comprehensive income attributable to noncontrolling interests	--	(1.1)	(4.9)	(6.0)	--	2.6	(3.4)
Comprehensive income attributable to entity	$ 1,911.5	$ 1,963.6	$ (1,956.8)	$ 1,918.3	$ 1,919.1	$ (1,918.3)	$ 1,919.1

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

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Comprehensive income	$ 1,743.4	$ 1,817.5	$ (1,785.7)	$ 1,775.2	$ 1,767.5	$ (1,769.0)	$ 1,773.7
Comprehensive income attributable to noncontrolling interests	--	(4.6)	(3.2)	(7.8)	--	1.6	(6.2)
Comprehensive income attributable to entity	$ 1,743.4	$ 1,812.9	$ (1,788.9)	$ 1,767.4	$ 1,767.5	$ (1,767.4)	$ 1,767.5

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Cash Flows
Nine Months Ended September 30, 2013

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Operating activities:							
Net income	$ 1,897.2	$ 1,958.0	$ (1,952.0)	$ 1,903.2	$ 1,898.0	$ (1,899.8)	$ 1,901.4
Reconciliation of net income to net cash flows provided by operating activities:							
Depreciation, amortization and accretion	105.3	797.0	--	902.3	--	--	902.3
Equity in income of unconsolidated affiliates	(1,936.2)	(141.9)	1,952.0	(126.1)	(1,899.2)	1,899.2	(126.1)
Distributions received from unconsolidated affiliates	3,421.1	180.7	(3,414.2)	187.6	1,830.9	(1,830.9)	187.6
Net effect of changes in operating accounts and other operating activities	(1,371.4)	889.7	(11.0)	(492.7)	(6.6)	0.3	(499.0)
Net cash flows provided by operating activities	2,116.0	3,683.5	(3,425.2)	2,374.3	1,823.1	(1,831.2)	2,366.2
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(292.1)	(2,101.2)	--	(2,393.3)	--	--	(2,393.3)
Proceeds from asset sales and insurance recoveries	57.5	198.8	--	256.3	--	--	256.3
Other investing activities	(2,366.7)	(485.6)	2,051.8	(800.5)	(1,135.2)	1,135.2	(800.5)
Cash used in investing activities	(2,601.3)	(2,388.0)	2,051.8	(2,937.5)	(1,135.2)	1,135.2	(2,937.5)
Financing activities:							
Borrowings under debt agreements	10,139.2	--	--	10,139.2	--	--	10,139.2
Repayments of debt	(8,761.7)	(29.9)	--	(8,791.6)	--	--	(8,791.6)
Cash distributions paid to partners	(1,831.2)	(3,420.6)	3,420.6	(1,831.2)	(1,778.3)	1,831.2	(1,778.3)
Cash distributions paid to noncontrolling interests	--	--	(6.4)	(6.4)	--	--	(6.4)
Cash contributions from noncontrolling interests	--	--	104.2	104.2	--	--	104.2
Net cash proceeds from issuance of common units	--	--	--	--	1,134.7	--	1,134.7
Cash contributions from owners	1,135.2	2,155.9	(2,155.9)	1,135.2	--	(1,135.2)	--
Other financing activities	(192.6)	0.1	--	(192.5)	(44.5)	--	(237.0)
Cash provided by (used in) financing activities	488.9	(1,294.5)	1,362.5	556.9	(688.1)	696.0	564.8
Net change in cash and cash equivalents	3.6	1.0	(10.9)	(6.3)	(0.2)	--	(6.5)
Cash and cash equivalents, January 1	--	28.0	(12.1)	15.9	0.2	--	16.1
Cash and cash equivalents, September 30	$ 3.6	$ 29.0	$ (23.0)	$ 9.6	$ --	$ --	$ 9.6

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

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	**Other Subsidiaries (Non-guarantor)**	**EPO and Subsidiaries Eliminations and Adjustments**	**Consolidated EPO and Subsidiaries**	**Enterprise Products Partners L.P. (Guarantor)**	**Eliminations and Adjustments**	**Consolidated Total**
Operating activities:							
Net income	$ 1,804.4	$ 1,793.5	$ (1,785.7)	$ 1,812.2	$ 1,804.4	$ (1,806.0)	$ 1,810.6
Reconciliation of net income to net cash flows provided by operating activities:							
Depreciation, amortization and accretion	89.9	728.0	--	817.9	--	--	817.9
Equity in income of unconsolidated affiliates	(1,774.7)	(53.1)	1,785.6	(42.2)	(1,805.6)	1,805.6	(42.2)
Distributions received from unconsolidated affiliates	2,898.7	54.3	(2,885.5)	67.5	1,643.4	(1,643.4)	67.5
Net effect of changes in operating accounts and other operating activities	(2,005.1)	1,057.8	1.4	(945.9)	(92.5)	0.4	(1,038.0)
Net cash flows provided by operating activities	1,013.2	3,580.5	(2,884.2)	1,709.5	1,549.7	(1,643.4)	1,615.8
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(161.2)	(2,536.7)	--	(2,697.9)	--	--	(2,697.9)
Proceeds from asset sales and insurance recoveries	1,109.1	58.3	--	1,167.4	--	--	1,167.4
Other investing activities	(2,161.7)	(254.2)	2,051.4	(364.5)	(571.5)	571.5	(364.5)
Cash used in investing activities	(1,213.8)	(2,732.6)	2,051.4	(1,895.0)	(571.5)	571.5	(1,895.0)
Financing activities:							
Borrowings under debt agreements	7,141.4	--	--	7,141.4	--	--	7,141.4
Repayments of debt	(5,706.5)	(9.5)	--	(5,716.0)	--	--	(5,716.0)
Cash distributions paid to partners	(1,643.4)	(2,889.7)	2,889.7	(1,643.4)	(1,613.4)	1,643.4	(1,613.4)
Cash distributions paid to noncontrolling interests	--	(7.1)	(4.2)	(11.3)	--	--	(11.3)
Cash contributions from noncontrolling interests	--	--	6.5	6.5	--	--	6.5
Net cash proceeds from issuance of common units	--	--	--	--	658.6	--	658.6
Cash contributions from owners	571.5	2,057.8	(2,057.8)	571.5	--	(571.5)	--
Other financing activities	(168.5)	--	--	(168.5)	(23.4)	--	(191.9)
Cash provided by (used in) financing activities	194.5	(848.5)	834.2	180.2	(978.2)	1,071.9	273.9
Net change in cash and cash equivalents	(6.1)	(0.6)	1.4	(5.3)	--	--	(5.3)
Cash and cash equivalents, January 1	9.7	21.3	(11.2)	19.8	--	--	19.8
Cash and cash equivalents, September 30	$ 3.6	$ 20.7	$ (9.8)	$ 14.5	$ --	$ --	$ 14.5

Note 18. Subsequent Event

On November 8, 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 $62.05 per unit. This underwritten offering generated net proceeds of $553.4 million, which were used for general company purposes.

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

For the three and nine months ended September 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:

/d	*= per day*	*MMBbls*	*= million barrels*
BBtus	*= billion British thermal units*	*MMBPD*	*= million barrels per day*
Bcf	*= billion cubic feet*	*MMBtus*	*= million British thermal units*
BPD	*= barrels per day*	*MMcf*	*= million cubic feet*
MBPD	*= thousand barrels per day*	*TBtus*	*= 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 liquefied petroleum gas or "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 51,000 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, 22 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 (November 12, 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.

Texas Express Pipeline and Related Gathering Systems Begin Operations

Our Texas Express Pipeline and two related NGL gathering systems initiated their start-up activities in October 2013, with commercial operations commencing effective November 1, 2013. The Texas Express Pipeline originates in Skellytown, Texas and extends approximately 580 miles to Mont Belvieu, Texas. The Texas Express Pipeline gives producers in West and Central Texas, the Rocky Mountains, southern Oklahoma, the Mid-continent and the Denver-Julesburg supply basin much-needed takeaway capacity for growing NGL production volumes and improved access to Mont Belvieu, which is the primary industry hub for domestic NGL production. The Texas Express Pipeline is owned by Texas Express Pipeline LLC, which is a joint venture among us and affiliates of Enbridge Energy Partners, L.P. ("Enbridge"), Anadarko Petroleum Corporation ("Anadarko") and DCP Midstream Partners LP. We operate the Texas Express Pipeline and own a 35% ownership interest in Texas Express Pipeline LLC.

NGL volumes from the Rocky Mountains, Permian Basin and Mid-continent regions will be transported to the Texas Express Pipeline using our Mid-America Pipeline System. NGL volumes from the Denver-Julesburg supply basin will be transported to the Texas Express Pipeline using the Front Range Pipeline, which is currently under construction and expected to be placed in service during the first quarter of 2014. We hold a one-third ownership interest in the joint venture that owns the Front Range Pipeline, and operate the pipeline.

In addition to the start of operations on the Texas Express Pipeline, service has also begun on two NGL gathering systems developed by Texas Express Gathering LLC, which is a second joint venture among Enbridge, Anadarko and us. We own a 45% ownership interest in Texas Express Gathering LLC. Enbridge serves as operator of the two gathering systems, which link natural gas processing plants in the Anadarko/Granite Wash and Central Texas/Barnett Shale production areas to the Texas Express Pipeline.

Plans to Construct Second LPG Export Facility

In October 2013, we announced plans to construct our second LPG export terminal on the Gulf Coast. This new marine export terminal will have the capability to handle Very Large Gas Carrier ("VLGC") class ships, which includes vessels having cargo capacities of up to 83,000 cubic meters (approximately 550,000 barrels). The initial loading rate for propane and butane exports at the new marine export terminal is expected to be approximately 11,000 barrels per hour, which would equate to approximately 6.0 to 6.5 MMBbls per month. Following the completion of site evaluation at potential locations in Louisiana and Texas, this new LPG marine export terminal is expected to be in service in the fourth quarter of 2015.

Upon completion of our second LPG marine export terminal, and the recently announced expansion of our existing LPG marine export terminal on the Houston Ship Channel (see below), we expect to have a combined loading capacity of 15.0 to 16.0 MMBbls per month of low-ethane propane and/or butane at our marine terminals. Both marine export terminals will have separate, dedicated pipelines that supply LPG from our large fractionation and storage complex at Mont Belvieu, Texas.

In addition to providing LPG export services, the new marine export terminal is being designed with the flexibility to add the necessary equipment to provide ethane export services. Our Mont Belvieu complex and Aegis Pipeline would complement the addition of ethane export capabilities at this new site.

Expansion of Houston Ship Channel LPG Export Terminal

In September 2013, we announced an expansion project at our Houston Ship Channel LPG export terminal that would increase our ability to load fully refrigerated, low-ethane propane cargoes from 7.5 MMBbls per month to 9.0 MMBbls per month. By enhancing the refrigeration capacity of the dock facility, the expansion project should enable us to load an additional three vessels per month for exporters. We recently completed an expansion of our LPG export terminal that increased its loading capability for low-ethane propane from 4.0 MMBbls per month to 7.5 MMBbls per month. Our LPG export terminal continues to benefit from increased NGL supplies from domestic shale plays and strong international demand for propane feedstocks used in ethylene cracking operations.

Start-Up of Seventh NGL Fractionator at Our Mont Belvieu Complex

In September 2013, we announced that the seventh NGL fractionator at our Mont Belvieu complex was placed in service. The new unit, which has the capacity to fractionate up to 85 MBPD of NGLs, increases total NGL fractionation capacity at our Mont Belvieu complex to approximately 570 MBPD. This fractionator, along with an eighth unit currently under construction, is designed to handle increasing NGL production from domestic shale plays, including the Eagle Ford in South Texas and other supply basins in the Rocky Mountains and Midcontinent regions.

Our eighth NGL fractionator is expected to be placed in service during the fourth quarter of 2013 and would increase total NGL fractionation capacity at our Mont Belvieu complex to approximately 655 MBPD. Our seventh and eighth NGL fractionators are owned by a joint venture, formed in June 2013, between us and Western Gas Partners, LP ("Western Gas"), which is an affiliate of Anadarko. We own 75% of the joint venture's membership interests, with Western Gas owning a 25% noncontrolling interest in the joint venture.

Expansion of Eagle Ford Crude Oil Pipeline System

In September 2013, we, along with Plains All American Pipeline, L.P. ("Plains"), announced an expansion of our Eagle Ford Crude Oil Pipeline System in South Texas. The expansion is expected to increase the pipeline system's capacity to transport light and medium grades of crude oil from 300 MBPD to 470 MBPD in order to accommodate expected volumes from Plains' Cactus pipeline. As currently planned, the expansion of our Eagle Ford Crude Oil Pipeline System would be completed in stages that include adding pumping capacity and looping certain segments of the existing system. The expansion also includes constructing an additional 2.3 MMBbls of operational storage capacity at Gardendale, Tilden and Corpus Christi, Texas. We expect the expansion to be completed during the second quarter of 2015.

Plans to Develop Refined Products Export Facilities on Texas Gulf Coast

In May 2013, we announced the development of a refined products export facility in Beaumont, Texas to meet growing demand for additional refined products export capability on the U.S. Gulf Coast. Export service at this marine terminal is expected to begin during the first quarter of 2014 and would accommodate Panamax class vessels. Panamax class vessels are medium-sized tanker ships designed to transit the existing lock chambers of the Panama Canal. This new export facility 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. In addition to the planned Beaumont export facility, we are evaluating the potential for a second refined products export facility on the Houston Ship Channel.

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 American 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 North American 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 the ECHO storage facility 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 pipeline distribution system that will be directly connected to refineries having an aggregate capacity of approximately 3.6 MMBPD. In addition, the ECHO storage facility, which is expected to have over 6.0 MMBbls of crude oil storage capacity following the expansion, will have access to our marine NGL and crude oil 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 stages beginning in the second quarter of 2014 through the first quarter 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 September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
Revenues	$ 12,093.3	$ 10,468.7	$ 34,625.7	$ 31,511.0
Costs and expenses:				
Operating costs and expenses:				
Cost of sales	10,371.3	8,794.0	29,522.1	26,655.0
Other operating costs and expenses	612.0	556.1	1,702.4	1,672.9
Depreciation, amortization and accretion	285.2	269.2	851.7	785.1
Gains attributable to asset sales and insurance recoveries	(10.2)	(2.6)	(68.4)	(34.1)
Non-cash asset impairment charges	15.2	43.1	53.3	57.6
Total operating costs and expenses	11,273.5	9,659.8	32,061.1	29,136.5
General and administrative costs	43.9	41.4	138.9	130.2
Total costs and expenses	11,317.4	9,701.2	32,200.0	29,266.7
Equity in income of unconsolidated affiliates	44.0	21.0	126.1	42.2
Operating income	819.9	788.5	2,551.8	2,286.5
Interest expense	(208.3)	(199.7)	(604.4)	(572.8)
Other, net	0.6	1.5	0.2	73.4
Benefit from (provision for) income taxes	(19.4)	(2.4)	(46.2)	23.5
Net income	592.8	587.9	1,901.4	1,810.6
Net income attributable to noncontrolling interests	(0.8)	(1.1)	(3.4)	(6.2)
Net income attributable to limited partners	$ 592.0	$ 586.8	$ 1,898.0	$ 1,804.4

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 September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
NGL Pipelines & Services:				
Sales of NGLs and related products	$ 3,929.8	$ 3,151.9	$ 10,831.3	$ 10,401.1
Midstream asset services	300.9	239.9	855.3	677.7
Total	4,230.7	3,391.8	11,686.6	11,078.8
Onshore Natural Gas Pipelines & Services:				
Sales of natural gas	590.7	608.2	1,954.1	1,691.6
Midstream services	244.8	238.3	716.6	708.9
Total	835.5	846.5	2,670.7	2,400.5
Onshore Crude Oil Pipelines & Services:				
Sales of crude oil	5,359.7	4,471.8	15,159.9	13,093.4
Midstream asset services	77.8	33.4	200.3	74.1
Total	5,437.5	4,505.2	15,360.2	13,167.5
Offshore Pipelines & Services:				
Sales of natural gas	0.1	0.2	0.3	0.3
Sales of crude oil	1.5	3.1	3.7	4.5
Midstream asset services	38.0	41.9	119.5	145.5
Total	39.6	45.2	123.5	150.3
Petrochemical & Refined Products Services:				
Sales of petrochemicals and refined products	1,390.1	1,498.9	4,271.5	4,166.9
Midstream asset services	159.9	181.1	513.2	547.0
Total	1,550.0	1,680.0	4,784.7	4,713.9
Total consolidated revenues	$ 12,093.3	$ 10,468.7	$ 34,625.7	$ 31,511.0

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
3rd Quarter	$ 3.58	$ 0.25	$ 1.03	$ 1.33	$ 1.35	$ 2.15	$ 0.68	$ 0.58	$ 105.82	$ 109.89
2013 Averages	$ 3.67	$ 0.26	$ 0.94	$ 1.38	$ 1.42	$ 2.14	$ 0.69	$ 0.59	$ 98.14	$ 109.48

(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) was $1.01 per gallon during the third quarter of each of 2013 and 2012. While average market prices at Mont Belvieu for ethane, normal butane and isobutane decreased quarter-to-quarter, the average market price of propane at Mont Belvieu increased 16% due to international demand for U.S. propane exports. According to recent U.S. Energy Information Administration ("EIA") statistics, propane volumes account for approximately 32% of NGLs produced from natural gas processing activities.

The weighted-average indicative market price for NGLs for the first nine months of 2013 was $0.99 per gallon compared to $1.15 per gallon during the first nine months of 2012 – a 14% period-to-period decrease. Ethane accounts for the largest volume of NGLs extracted from the natural gas stream. According to recent EIA statistics, ethane volumes account for approximately 35% of NGLs produced by natural gas processing activities. 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 $3.58 per MMBtu during the third quarter of 2013 versus $2.80 per MMBtu during the third quarter of 2012 – a 28% quarter-to-quarter increase. The Henry Hub market price of natural gas for the first nine months of 2013 averaged $3.67 per MMBtu compared to $2.58 per MMBtu during the first nine months of 2012 – a 42% 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. However, 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 $105.82 per barrel during the third quarter of 2013 compared to $92.22 per barrel during the third quarter of 2012. The NYMEX market price of WTI crude oil for the first nine months of 2013 averaged $98.14 per barrel compared to $96.21 per barrel during the first nine months of 2012. A significant factor in the increase in WTI crude oil prices has been the completion of midstream infrastructure projects, such as the reversal of our Seaway pipeline, that allowed crude oil production volumes formerly stranded at the Cushing hub to reach markets along the Gulf Coast.

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 averaged $109.89 per barrel during the third quarter of 2013 compared to $109.40 per barrel during the third quarter of 2012. LLS prices averaged $109.48 per barrel during the first nine months 2013 compared to $112.49 per barrel during the first nine months of 2012.

A decrease in our consolidated marketing revenues due to lower energy commodity sales prices may not result in 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 third quarter of 2013 increased $1.62 billion when compared to the third quarter of 2012. Revenues from the marketing of NGLs, crude oil and petrochemical products increased a combined $1.86 billion quarter-to-quarter primarily due to higher sales volumes. Revenues from the marketing of refined products decreased $267.6 million quarter-to-quarter primarily due to lower sales prices. Revenues from the marketing of natural gas decreased a net $17.6 million quarter-to-quarter primarily due to lower sales volumes, which accounted for a $198.3 million decrease, partially offset by higher sales prices, which accounted for a $180.7 million increase. Revenues from midstream asset services increased $86.8 million quarter-to-quarter primarily due to contributions from our recently completed assets that have started operations 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 (e.g., our seventh NGL fractionator).

For the nine months ended September 30, 2013, revenues increased $3.11 billion when compared to the nine months ended September 30, 2012. Revenues from the marketing of crude oil increased $2.07 billion period-to-period primarily due to higher sales volumes, which accounted for a $1.28 billion increase, and sale prices, which accounted for an additional $785.9 million increase. Revenues from the marketing of NGLs increased a net $430.2 million period-to-period primarily due to higher sales volumes, which accounted for a $2.41 billion increase, partially offset by lower sales prices, which accounted for a $1.98 billion decrease. Revenues from the marketing of natural gas and petrochemical products increased a net $407.0 million period-to-period primarily due to higher sales prices, which accounted for a $951.1 million increase, partially offset by lower sales volumes, which accounted for a $544.1 million decrease. Revenues from the marketing of refined products decreased a net $23.2 million period-to-period primarily due to lower sales prices, which accounted for a $545.2 million decrease, which was nearly offset by the impact of higher sales volumes, which accounted for a $522.0 million increase. Revenues from midstream asset services increased $251.7 million period-to-period primarily due to contributions from recently completed assets that have started operations in the Eagle Ford Shale supply basin and at our Mont Belvieu complex.

Total operating costs and expenses for the third quarter of 2013 increased $1.61 billion when compared to the third quarter of 2012 primarily due to a $1.58 billion increase in our cost of sales amounts. The cost of sales associated with our marketing of NGLs and crude oil increased $1.68 billion quarter-to-quarter primarily due to higher sales volumes. Cost of sales associated with our marketing of petrochemical products increased $226.5 million quarter-to-quarter primarily due to higher purchase prices. Cost of sales associated with our marketing of refined products decreased $277.5 million quarter-to-quarter primarily due to lower purchase prices. Finally, the cost of sales associated with our marketing of natural gas decreased a net $53.6 million quarter-to-quarter primarily due to lower sales volumes, which accounted for a $163.8 million decrease, partially offset by higher natural gas prices, which accounted for a $110.2 million increase. Other operating costs and expenses increased $55.9 million quarter-to-quarter primarily due to higher maintenance costs and the addition of operating costs of newly constructed assets that have recently started operations.

For the nine months ended September 30, 2013, total operating costs and expenses increased $2.92 billion when compared to the same period in 2012 primarily due to a $2.87 billion increase in cost of sales. The cost of sales associated with our marketing of crude oil increased $1.92 billion period-to-period primarily due to higher sales volumes, which accounted for a $1.21 billion increase, and purchase prices, which accounted for an additional $708.6 million increase. Cost of sales associated with the marketing of NGLs increased a net $706.2 million period-to-period primarily due to higher sales volumes, which accounted for a $2.23 billion increase, partially offset by lower purchase prices, which accounted for a $1.53 billion decrease. Cost of sales associated with our marketing of natural gas and petrochemical products increased a net $347.3 million period-to-period primarily due to higher purchase prices, which accounted for an $839.9 million increase, partially offset by lower sales volumes, which accounted for a $492.6 million decrease. Cost of sales associated with the marketing of refined products decreased a net $98.9 million period-to-period primarily due to lower purchase prices, which accounted for a $643.4 million decrease, which was nearly offset by the impact of higher sales volumes, which accounted for a $544.5 million increase. Other operating costs and expenses increased a net $29.5 million period-to-period primarily due to (i) the addition of operating costs of newly constructed assets that have recently started operations and higher overall maintenance costs, which accounted for a combined $117.0 million period-to-period increase in costs, partially offset by (ii) reductions in operating costs due to asset sales (e.g., the sale of our chemical trucking assets in January 2013), which accounted for an $87.5 million period-to-period decrease.

Depreciation, amortization and accretion in operating costs and expenses increased $16.0 million for the third quarter of 2013 when compared to the third quarter of 2012 and $66.6 million for the nine months ended September 30, 2013 when compared to the same nine-month period in 2012. These increases were primarily due to recently constructed assets being placed into service.

Gains attributable to asset sales and insurance recoveries in operating costs and expenses were $10.2 million during the third quarter of 2013 compared to $2.6 million during the third quarter of 2012. We recorded gains of $68.4 million attributable to asset sales and insurance recoveries for the nine months ended September 30, 2013 compared to $34.1 million for the nine months ended September 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. We recognized $8.8 million of gains attributable to the receipt of nonrefundable cash insurance proceeds related to our West Storage claims during the nine months ended September 30, 2013 compared to $30.0 million of such gains for the nine months ended September 30, 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 third 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 $15.2 million and $43.1 million of non-cash asset impairment charges during the third quarters of 2013 and 2012, respectively. For the nine months ended September 30, 2013, we recorded $53.3 million of such charges compared to $57.6 million for the same period in 2012. Our non-cash asset impairment charges for the nine months ended September 30, 2013 primarily represent the abandonment of crude oil and natural gas pipeline segments in Texas, Oklahoma and the Gulf of Mexico, certain refined products terminal assets in Texas, and an NGL storage cavern in Arizona. Our asset impairment charges for the nine months ended September 30, 2012 primarily represent the abandonment of crude oil and natural gas pipeline segments in Texas and the Gulf of Mexico.

General and administrative costs increased $2.5 million for the third quarter of 2013 and $8.7 million for the nine months ended September 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 $23.0 million for the third quarter of 2013 and $83.9 million for the nine months ended September 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 third quarter of 2013 increased $8.6 million when compared to the third quarter of 2012. Likewise, interest expense for the nine months ended September 30, 2013 increased $31.6 million when compared to the same nine-month period in 2012. Our average debt principal balance for the third quarter of 2013 was $17.25 billion compared to $15.7 billion for the third quarter of 2012. With respect to the nine months ended September 30, 2013, our average debt principal balance was $17.03 billion compared to $15.04 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. On a weighted-average basis, the interest rates we paid on our consolidated debt obligations were 5.3% and 5.4% for the three and nine months ended September 30, 2013, respectively, and were 5.7% for both the three and nine months ended September 30, 2012. The $8.6 million quarter-to-quarter increase in interest expense was primarily due to increased debt associated with new assets being placed into service, which accounted for an approximate $17.5 million increase, partially offset by the effects of lower interest rates (including related hedging results), which accounted for a $9.0 million decrease. The $31.6 million period-to-period increase in interest expense was also primarily due to increased debt associated with new assets being placed into service, which accounted for an approximate $67.6 million increase, partially offset by the effects of lower interest rates (including related hedging results), which accounted for a $36.5 million decrease. For a discussion of our consolidated debt obligations and capital spending program, see "Liquidity and Capital Resources" within this Item 2.

Other non-operating income for the nine months ended September 30, 2012 includes $68.8 million 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.

Income tax expense increased $17.0 million for the third quarter of 2013 and $69.7 million for the nine months ended September 30, 2013 when compared to the same respective periods in 2012. Provision for income taxes primarily reflects our state tax obligations under the Revised Texas Franchise Tax (the "Texas Margin Tax"). We recognized an overall net income tax benefit of $23.5 million for the nine months ended September 30, 2012, which was primarily due to a $46.5 million net income tax benefit related to the conversion of certain of our subsidiaries to limited liability companies during the first quarter of 2012, partially offset by accruals for the Texas Margin Tax. For additional information regarding our provision for income taxes, see Note 2 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Business Segment Highlights

Total segment gross operating margin was $1.15 billion for the third quarter of 2013 compared to $1.14 billion for the third quarter of 2012. For the nine months ended September 30, 2013 and 2012, total segment gross operating margin was $3.53 billion and $3.23 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 September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
Segment gross operating margin:				
Natural gas processing and related NGL marketing activities	$ 293.4	$ 352.4	$ 826.9	$ 1,112.9
NGL pipelines and related storage	230.7	195.0	650.7	521.2
NGL fractionation	115.5	68.4	299.4	202.4
Total	$ 639.6	$ 615.8	$ 1,777.0	$ 1,836.5
Selected volumetric data:				
Equity NGL production (MBPD) (1)	120	99	120	102
Fee-based natural gas processing (MMcf/d) (2)	4,660	4,462	4,589	4,277
NGL transportation volumes (MBPD)	2,867	2,473	2,717	2,440
NGL fractionation volumes (MBPD)	736	653	707	643

(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 $59.0 million in the third quarter of 2013 when compared to the third 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 $49.8 million quarter-to-quarter primarily due to lower processing margins in the third quarter of 2013. In general, natural gas processing margins are lower in 2013 compared to 2012 due to lower NGL prices and higher natural gas prices in each respective period. Gross operating margin from our Pioneer natural gas processing plant in Wyoming decreased $20.0 million quarter-to-quarter primarily due to the effects of ethane rejection and overall production declines, both of which lowered equity NGL production volumes 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 continued low prices for natural gas.

Gross operating margin from our South Texas natural gas processing plants increased a net $2.0 million quarter-to-quarter primarily due to higher volumes, which accounted for a $14.8 million increase, and higher processing fees, which resulted in an $8.7 million increase, partially offset by lower processing margins, which accounted for a $21.3 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 other natural gas processing plants for the third quarter of 2013 decreased a combined $5.7 million when compared to the third quarter of 2012 primarily due to lower processing margins in the third quarter of 2013. Lastly, gross operating margin from our NGL marketing activities increased a net $14.5 million quarter-to-quarter primarily due to higher sales volumes, which accounted for a $58.5 million increase, partially offset by lower sales margins, which accounted for a $44.3 million decrease.

Gross operating margin from these businesses decreased $286.0 million in the nine months ended September 30, 2013 when compared to the same period in 2012. Gross operating margin from our Meeker and Pioneer natural gas processing plants decreased $158.7 million and $94.4 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 a net $16.6 million period-to-period primarily due to higher volumes, which accounted for a $50.6 million increase, and higher processing fees, which resulted in a $22.3 million increase, partially offset by lower processing margins, which accounted for a $54.4 million decrease. Gross operating margin from our remaining natural gas processing plants decreased a combined $40.1 million period-to-period primarily due to lower processing margins in the 2013 period.

Gross operating margin from our NGL marketing activities for the nine months ended September 30, 2013 increased a net $24.3 million when compared to the same period in 2012 primarily due to higher sales volumes, which accounted for a $153.6 million period-to-period increase, partially offset by lower sales margins, which accounted for a $128.9 million decrease.

Gross operating margin for the nine months ended September 30, 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 third quarter of 2013 increased $35.7 million when compared to the third quarter of 2012 largely due to strong results from our South Texas and Houston region assets. Gross operating margin from our Houston Ship Channel LPG export terminal and related Channel Pipeline increased a combined $18.2 million quarter-to-quarter primarily due to increased volumes. As a result of high demand for export services, loading volumes at our Houston Ship Channel LPG export terminal increased 130 MBPD quarter-to-quarter and volumes on the related Channel Pipeline increased 125 MBPD quarter-to-quarter. Gross operating margin from our South Texas NGL Pipeline System increased $17.7 million quarter-to-quarter primarily due to a 158 MBPD increase in transportation volumes associated with higher Eagle Ford Shale production.

Gross operating margin from our Dixie Pipeline and related NGL terminals increased $4.6 million quarter-to-quarter primarily due to a 30 MBPD increase in transportation volumes. Transportation volumes reflect higher demand for propane in the markets served by our Dixie Pipeline during the third quarter of 2013 compared to the same period in 2012.

Lastly, transportation volumes for our Mid-America Pipeline System, Seminole Pipeline and related NGL terminals decreased 82 MBPD quarter-to-quarter primarily due to lower NGL production from Rocky Mountain gas plants caused by ethane rejection and reduced demand for NGL transportation services between Conway, Kansas and Mont Belvieu, Texas. Gross operating margin for these assets decreased a net $3.0 million quarter-to-quarter with lower transportation volumes accounting for a $10.8 million decrease, partially offset by higher system-wide tariffs and other fees, which resulted in a $7.5 million quarter-to-quarter increase in gross operating margin.

With respect to the nine months ended September 30, 2013, gross operating margin from NGL pipelines and related storage assets increased $129.5 million when compared to the same period in 2012 primarily 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 $60.6 million period-to-period primarily due to a 112 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 $33.8 million period-to-period primarily due to increased volumes. Loading volumes at our Houston Ship Channel LPG export terminal and transportation volumes on the related Channel Pipeline increased 92 MBPD and 93 MBPD period-to-period, respectively.

Gross operating margin from our Dixie Pipeline and related NGL terminals increased $15.7 million period-to-period primarily due to a 30 MBPD increase in transportation volumes, which accounted for $8.8 million of the increase after taking into account associated operating costs, and higher transportation and other fees, which accounted for $6.9 million of the increase. Transportation volumes on the Dixie Pipeline were negatively impacted during 2012 due to downtime associated with pipeline integrity projects and warmer than normal winter weather.

Gross operating margin from our Mid-America Pipeline System, Seminole Pipeline and related NGL terminals increased a net $1.6 million period-to-period. A $31.1 million increase in revenues associated with higher system-wide tariffs and other fees, combined with a $9.1 million decrease in operating costs primarily due to pipeline gains during the 2013 period, was partially offset by a $38.6 million decrease in gross operating margin attributable to a 97 MBPD decrease in transportation volumes primarily due to ethane rejection.

NGL fractionation

Gross operating margin from NGL fractionation for the third quarter of 2013 increased $47.1 million when compared to the third quarter of 2012 primarily due to higher fees and volumes at our Mont Belvieu NGL fractionators. Gross operating margin from our Mont Belvieu NGL fractionators increased $40.0 million quarter-to-quarter primarily due to higher average fractionation and other fees, which accounted for a $22.0 million increase, and an increase in fractionation volumes of 107 MBPD (net to our ownership interest), which accounted for an additional $18.0 million increase after taking into account associated operating costs. Our Mont Belvieu NGL fractionators continue to benefit from increased NGL production volumes from the Eagle Ford Shale. In addition, operating results increased due to the start-up of our sixth and seventh NGL fractionators at Mont Belvieu, which commenced operations in October 2012 and September 2013, respectively.

With respect to the nine months ended September 30, 2013, gross operating margin from NGL fractionation increased $97.0 million when compared to the same period in 2012 primarily due to higher results from our Mont Belvieu NGL fractionators. Higher average fractionation and other fees attributable to our Mont Belvieu NGL fractionators during the nine months ended September 30, 2013 accounted for a $57.5 million period-to-period increase. Also, NGL fractionation volumes for the nine months ended September 30, 2013 at our Mont Belvieu complex increased 91 MBPD period-to-period (net to our ownership interest), which resulted in a $30.1 million period-to-period increase in gross operating margin after taking into account associated operating costs.

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 September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
Segment gross operating margin	$ 213.4	$ 183.5	$ 601.9	$ 565.5
Selected volumetric data:				
Natural gas transportation volumes (BBtus/d)	12,969	14,182	13,115	13,703

Gross operating margin from onshore natural gas pipelines and services for the third quarter of 2013 increased $29.9 million when compared to the third quarter of 2012. Gross operating margin from our Texas Intrastate System increased $24.1 million quarter-to-quarter primarily due to higher firm capacity reservation revenues. Increased natural gas production from the Eagle Ford Shale supply basin, in large part a by-product of increased NGL and crude oil production, continues to support demand for our natural gas transportation services on the Texas Intrastate System. Natural gas transportation volumes for the Texas Intrastate System increased 43 BBtus/d quarter-to-quarter. Gross operating margin from our natural gas marketing activities increased $15.1 million quarter-to-quarter primarily due to higher sales margins.

Gross operating margin from our San Juan Gathering System increased $3.4 million quarter-to-quarter primarily due to higher gathering fees, which are indexed to natural gas prices. Gross operating margin from our Jonah, Piceance Basin and Haynesville Gathering Systems decreased a combined $13.0 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. Collectively, natural gas transportation volumes for these four gathering systems decreased 933 BBtus/d quarter-to-quarter. Transportation volumes for our Acadian Gas System declined 257 BBtus/d quarter-to-quarter primarily due to lower volumes from the Haynesville supply basin. However, due to demand fees paid by shippers on the Haynesville Extension, gross operating margin for the Acadian Gas System decreased only $4.3 million quarter-to-quarter.

With respect to the nine months ended September 30, 2013, gross operating margin from onshore natural gas pipelines and services increased $36.4 million. Gross operating margin from our Texas Intrastate System increased $53.8 million period-to-period primarily due to higher firm capacity reservation revenues. Gross operating margin from our natural gas marketing activities increased $19.7 million period-to-period primarily due to higher sales margins. Gross operating margin from our Jonah, Piceance Basin and Haynesville Gathering Systems decreased a combined $28.1 million period-to-period primarily due to lower gathering volumes. Gross operating margin from our Acadian Gas System decreased $10.2 million period-to-period primarily due to higher operating expenses, which accounted for $4.9 million of the decrease, and lower sales margins, which accounted for a $4.7 million decrease. Lastly, gross operating margin from our San Juan Gathering System increased a net $1.8 million period-to-period primarily due to higher gathering fees, which are indexed to natural gas prices and accounted for a $13.1 million increase, partially offset by the effects of lower gathering volumes, which accounted for a $9.0 million decrease.

Overall, natural gas transportation volumes for the nine months ended September 30, 2013 decreased a net 588 BBtus/d when compared to the first nine months of 2012 primarily due to a combined 798 BBtus/d decrease in gathering volumes on our Jonah, Piceance Basin, Haynesville and San Juan gathering systems partially offset by increased volumes of 247 BBtus/d on our Texas Intrastate 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 September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
Segment gross operating margin	$ 146.0	$ 117.6	$ 579.6	$ 252.7
Selected volumetric data:				
Crude oil transportation volumes (MBPD)	1,252	820	1,139	791

Gross operating margin from our onshore crude oil pipelines and services business for the third quarter of 2013 increased a net $28.4 million when compared to the third quarter of 2012 primarily due to higher volumes on our crude oil pipeline systems partially offset by lower margins from our crude oil marketing activities. Gross operating margin from our South Texas Crude Oil Pipeline System increased $50.6 million quarter-to-quarter primarily due to a 137 MBPD increase in transportation volumes on the Eagle Ford Expansion pipeline, which commenced operations in June 2012. Equity earnings from our investments in crude oil pipeline joint ventures (Seaway and Eagle Ford) increased $17.8 million quarter-to-quarter primarily due to a 234 MBPD increase in transportation volumes (net to our interest) attributable to the completion of expansion capital projects on these systems. Gross operating margin from our crude oil marketing and related activities decreased $41.3 million quarter-to-quarter primarily due to lower sales margins attributable to the tightening of price differentials in the markets we serve.

With respect to the nine months ended September 30, 2013, gross operating margin from onshore crude oil pipelines and services increased $326.9 million period-to-period primarily due to higher volumes on our crude oil pipeline systems and results from our crude oil marketing activities. Gross operating margin from our South Texas Crude Oil Pipeline System increased $155.2 million period-to-period primarily due to volumes attributable to the Eagle Ford Expansion pipeline, which transported 170 MBPD during the nine months ended September 30, 2013. Equity earnings from our investments in crude oil pipeline joint ventures increased $80.4 million primarily due to a 194 MBPD increase in transportation volumes (net to our interest). Gross operating margin from our crude oil marketing and related activities increased $82.8 million period-to-period primarily due to higher sales margins during the first half of 2013.

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 September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
Segment gross operating margin	$ 37.9	$ 40.6	$ 118.1	$ 131.0
Selected volumetric data:				
Crude oil transportation volumes (MBPD)	314	293	306	289
Natural gas transportation volumes (BBtus/d)	665	760	706	876
Platform natural gas processing (MMcf/d)	185	238	217	306
Platform crude oil processing (MBPD)	16	14	15	17

Gross operating margin from our offshore pipelines and services business decreased $2.7 million for the third quarter of 2013 when compared to the third quarter of 2012 largely due to lower results from our Independence Hub platform and related Independence Trail pipeline. Collectively, these two assets posted a $1.6 million quarter-to-quarter decrease in gross operating margin primarily due to lower platform processing and pipeline throughput volumes. Also, this segment's gross operating margin for the third quarter of 2012 included a benefit of $1.1 million associated with reduced insurance costs.

Gross operating margin from our offshore crude oil pipeline business was $24.2 million for the third quarter of 2013, representing approximately 64% of this segment's gross operating margin. This compares to $22.1 million for the third quarter of 2012 or 54% of segment gross operating margin. We expect that gross operating margin from crude oil pipelines will represent an increasing share of the earnings from this segment as crude oil transportation volumes increase. Exploration and production companies continue to focus their efforts in the Gulf of Mexico on crude oil developments.

With respect to the nine months ended September 30, 2013, gross operating margin from offshore pipelines and services decreased $12.9 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 and lower transportation volumes on our High Island Offshore System ("HIOS"), partially offset by higher equity earnings from our investment in the Cameron Highway Oil Pipeline ("Cameron Highway") and lower insurance costs. Collectively, gross operating margin from our Independence Hub platform and Trail pipeline decreased $19.8 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 nine-month periods, and lower platform processing and pipeline throughput volumes during the 2013 period, which accounted for $10.1 million of the decrease in gross operating margin. Natural gas processing volumes on the Independence Hub platform decreased 85 MMcf/d period-to-period (68 MMcf/d net to our interest) and natural gas transportation volumes on the Independence Trail pipeline decreased 64 BBtus/d period-to-period. Gross operating margin from HIOS decreased $3.8 million period-to-period primarily due to a 45 BBtus/d decrease in natural gas transportation volumes. Equity earnings from Cameron Highway increased $6.5 million period-to-period primarily due to a 26 MBPD increase (net to our interest) in crude oil transportation volumes.

Gross operating margin for this segment also benefited from a $6.4 million period-to-period 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 have continued to self-insure these assets 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.

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 September 30,		For the Nine Months Ended September 30,	
	2013	**2012**	**2013**	**2012**
Segment gross operating margin:				
Propylene fractionation and related activities	$ 27.9	$ 55.6	$ 89.0	$ 159.5
Butane isomerization	27.4	25.5	78.2	71.2
Octane enhancement and related plant operations	40.8	50.1	122.1	87.7
Refined products pipelines and related activities	2.8	7.0	108.1	37.2
Marine transportation and other	18.2	43.9	53.3	81.6
Total	$ 117.1	$ 182.1	$ 450.7	$ 437.2
Selected volumetric data:				
Propylene fractionation volumes (MBPD)	74	73	71	73
Butane isomerization volumes (MBPD)	100	104	94	95
Octane additive and related plant production volumes (MBPD)	19	19	18	15
Transportation volumes, primarily refined products and petrochemicals (MBPD)	711	713	693	677

Propylene fractionation and related activities

Gross operating margin from our propylene fractionation and related petrochemical marketing activities decreased $27.7 million for the third quarter of 2013 when compared to the third quarter of 2012. Likewise, gross operating margin decreased $70.5 million for the nine months ended September 30, 2013 when compared to the same period in 2012. These decreases were primarily due to lower propylene sales margins.

Butane isomerization

Gross operating margin from butane isomerization for the third quarter of 2013 increased $1.9 million when compared to the third quarter of 2012. Likewise, gross operating margin for the first nine months of 2013 increased $7.0 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 the related high purity isobutylene plant operations decreased a combined $9.3 million for the third quarter of 2013 when compared to the third quarter of 2012 primarily due to lower sales margins, which accounted for a $4.3 million decrease, lower sales volumes, which accounted for a $2.4 million decrease, and higher operating costs, which accounted for an additional $3.2 million decrease. The increase in operating expenses was largely due to plant maintenance activities.

With respect to the nine months ended September 30, 2013, gross operating margin for these facilities increased $34.4 million when compared to the same period in 2012. Our octane enhancement facility experienced several periods of extended downtime for maintenance during the 2012 period, which negatively impacted the facility's operating results for such period. The $34.4 million period-to-period increase in gross operating margin was primarily due to higher sales margins, which accounted for a $26.7 million increase, and higher sales volumes, which accounted for a $17.6 million increase, partially offset by higher plant maintenance costs, which accounted for a $6.8 million decrease.

Refined products pipelines and related activities

Gross operating margin from refined products pipelines and related activities for the third quarter of 2013 decreased a net $4.2 million when compared to the third quarter of 2012 primarily due to lower results from our TE Products Pipeline, partially offset by higher earnings from our refined products marketing activities. Gross operating margin from our TE Products Pipeline decreased $14.6 million quarter-to-quarter primarily due to higher maintenance expenses, which accounted for $12.0 million of the decrease. Results from our refined products marketing activities increased $7.7 million quarter-to-quarter primarily due to higher sales margins.

With respect to the nine months ended September 30, 2013, gross operating margin from our refined products pipelines and related activities increased $70.9 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 a net $28.1 million period-to-period primarily due to higher transportation fees, which accounted for a $44.5 million increase, partially offset by a $20.1 million decrease in gross operating margin attributable to lower refined products interstate transportation volumes. The higher transportation fees period-to-period 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. Gross operating margin from our refined products terminals increased $25.8 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. Results from our refined products marketing activities increased $16.6 million period-to-period primarily due to higher sales margins.

Marine transportation and other

Gross operating margin from marine transportation and other segment services decreased $25.7 million for the third quarter of 2013 when compared to the third quarter of 2012. Likewise, gross operating margin decreased $28.3 million for the nine months ended September 30, 2013 versus the same period in 2012. Results attributable to our marine transportation business for the third quarter of 2012 and the nine months ended September 30, 2012 include a $24.0 million gain recorded in connection with a legal settlement.

Liquidity and Capital Resources

At September 30, 2013, we had $3.86 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 September 30, 2013 was $9.6 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.

On October 1, 2013, we filed a registration statement with the SEC covering the issuance of up to $1.25 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. The new registration statement was declared effective on October 15, 2013 and replaced our prior registration statement with respect to the at-the-market program, which was filed with the SEC in March 2012 and covered the issuance of up to $1.0 billion of our common units. Immediately prior to the effectiveness of the new registration statement, we had the capacity to issue additional common units under the at-the-market program up to an aggregate sales price of $334.2 million (after giving effect to sales of common units previously made under the program). Following the effectiveness of the new registration statement, we now have the capacity to issue additional common units under our at-the-market program up to an aggregate sales price of $1.25 billion.

Consolidated Debt

We had $17.53 billion of principal amounts outstanding under consolidated debt agreements at September 30, 2013. The following table presents contractually scheduled maturities of our consolidated debt obligations outstanding at September 30, 2013 for the periods indicated (dollars in millions):

		Scheduled Maturities of Debt					
	Total	**Remainder of 2013**	**2014**	**2015**	**2016**	**2017**	**After 2017**
Commercial Paper Notes	$ 550.0	$ 550.0	$ --	$ --	$ --	$ --	$ --
Multi-Year Revolving Credit Facility	100.0	--	--	--	--	--	100.0
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	$ 17,532.7	$ 550.0	$ 1,150.0	$ 1,300.0	$ 750.0	$ 800.0	$ 12,982.7

At September 30, 2013, our current maturities of debt totaled $1.05 billion. 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 nine months ended September 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	7,284,807	435.5
Common units issued in connection with the DRIP and EUPP	3,760,154	212.6
Total	20,244,961	$ 1,134.7

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.

During the nine months ended September 30, 2013, we sold 7,624,689 common units under our at-the-market program for aggregate gross proceeds of $460.4 million. After taking into account applicable costs, these transactions resulted in net proceeds of $456.3 million, of which $435.5 million was received and 7,284,807 common units issued and outstanding as of September 30, 2013. The remaining 339,882 common units sold under the program during the nine months ended September 30, 2013 were issued in October 2013 upon closing of the sales of such common units and receipt of the $20.8 million balance of proceeds. After taking into account the aggregate sale price of common units sold under our at-the-market program through September 30, 2013 and the new registration statement that was declared effective on October 15, 2013, we have the capacity to issue additional common units under this program up to an aggregate sales price of $1.25 billion.

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 a total of 3,649,323 common units under our DRIP during the nine months ended September 30, 2013, which generated net proceeds of $206.0 million. After taking into account the number of common units issued under the DRIP through September 30, 2013, we have the capacity to issue an additional 19,843,969 common units under this plan.

In January 2013, affiliates of privately held EPCO, which own our general partner and approximately 36.8% of our limited partner interests at September 30, 2013, expressed their willingness to purchase at least $100 million of our common units during 2013 through our DRIP. During the nine months ended September 30, 2013, these EPCO affiliates reinvested $75.0 million, resulting in the issuance of 1,331,774 common units under our DRIP (this amount being a component of the total common units issued in total under the DRIP during the first nine months of 2013). On November 7, 2013, these affiliates reinvested an additional $25.0 million under the DRIP, which increased their total investment for 2013 to $100.0 million.

In addition to the DRIP, we have registration statements on file with the SEC authorizing the issuance of our common units in connection with an employee unit purchase plan (or "EUPP"). In September 2013, our unitholders approved the amendment and restatement of the EUPP. As a result, the maximum number of common units issuable under the EUPP increased from 440,879 common units to 4,000,000 common units. In addition, the term of the EUPP was extended to September 2023. We issued 110,831 common units under our EUPP during the nine months ended September 30, 2013, which generated net proceeds of $6.6 million. After taking into account the number of common units issued under the EUPP through September 30, 2013, we may issue an additional 3,744,326 common units under the amended and restated EUPP.

The net cash proceeds we received from the issuance of common units during the nine months ended September 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.

In November 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 $62.05 per unit. This underwritten offering generated net proceeds of $553.4 million, which were used for general company purposes.

Credit Ratings

As of November 12, 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 Nine Months Ended September 30,	
	2013	2012
Net cash flows provided by operating activities	$ 2,366.2	$ 1,615.8
Cash used in investing activities	2,937.5	1,895.0
Cash provided by financing activities	564.8	273.9

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 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 Nine Months Ended September 30, 2013 with Nine Months Ended September 30, 2012

Operating Activities. Net cash flows provided by operating activities for the nine months ended September 30, 2013 increased $750.4 million when compared to the same period in 2012. The increase in cash flow was primarily due to a $234.0 million period-to-period increase in cash attributable to overall higher partnership income (after adjusting our $90.8 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) and a $396.3 million period-to-period increase in cash flow generally attributable to the timing of cash receipts and disbursements related to operations. In addition, cash distributions from unconsolidated affiliates increased $120.1 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 nine months ended September 30, 2013 increased $1.04 billion when compared to the same period in 2012. The period-to-period increase in cash used for investing activities was primarily due to higher investments in 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 $416.6 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 $1.17 billion for the nine months ended September 30, 2012 to $256.3 million for the nine months ended September 30, 2013. Proceeds for the 2012 period include 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 nine 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, $65.0 million from the sale of certain pipeline linefill volumes, $35.3 million we received from the sale of lubrication oil and specialty chemical distribution assets and $29.5 million we received from the sale of chemical trucking assets.

Capital spending for consolidated property, plant and equipment, net of contributions in aid of construction costs, decreased $304.6 million period-to-period.

Financing Activities. Cash provided by financing activities was $564.8 million for the first nine months of 2013 compared to $273.9 million for the first nine months of 2012. The $290.9 million period-to-period increase in cash flows provided by financing activities was primarily due to the following:

- § Net cash proceeds from the issuance of common units increased $476.1 million period-to-period. In total, we issued an aggregate of 20,244,961 common units during the first nine months of 2013 for which we received $1.13 billion of net cash proceeds. This compares to 12,856,557 common units we issued during the first nine months of 2012 and the receipt of $658.6 million of associated net cash proceeds. 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.

- § Cash contributions from noncontrolling interests increased $97.7 million period-to-period primarily due to contributions received in connection with our joint venture with Western Gas involving two new NGL fractionators, one of which remains under construction, at our complex in Mont Belvieu, Texas.

- § Cash distributions paid to limited partners increased $164.9 million period-to-period due to increases in both the number of distribution-bearing common units outstanding and the quarterly distribution rates per unit.

- § Net borrowings under our consolidated debt agreements decreased $77.8 million period-to-period. EPO issued $2.25 billion and repaid $1.2 billion in principal amount of senior notes during the first nine months of 2013, compared to the issuance of $2.5 billion and repayment of $1.0 billion in principal amount of senior notes during the first nine months of 2012. In addition, net borrowings under EPO's $3.5 Billion Multi-Year Revolving Credit Facility were $100.0 million for the first nine months of 2013 compared to $65.0 million in net repayments for the first nine months of 2012. Net borrowings under EPO's commercial paper program during the first nine months of 2013 were $202.6 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.

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 Nine Months Ended September 30,	
	2013	2012
Capital spending for property, plant and equipment, net of contributions in aid of construction costs	$ 2,393.3	$ 2,697.9
Capital spending for investments in unconsolidated affiliates	768.4	351.8
Other investing activities	1.0	32.1
Total capital spending	$ 3,162.7	$ 3,081.8

Our payments for growth capital spending totaled $3.0 billion for the nine months ended September 30, 2013. Our most significant growth capital expenditures for the first nine 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 $4.5 billion, which includes estimated expenditures of $4.2 billion for growth capital projects and $300 million to $325 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 September 30, 2013, we had approximately $1.47 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.

During the first nine months of 2013, we placed approximately $1.5 billion of major capital projects into service. We expect to complete construction and begin commercial operations related to growth capital spending representing approximately $925 million of investment during the fourth quarter of 2013. These projects include:

§ the Texas Express Pipeline and related Texas Express Gathering System;

§ our eighth NGL fractionator at Mont Belvieu;

§ various mixed NGL pipeline expansions and pump upgrades at our Mont Belvieu complex; and

§ an extension of the Seaway Pipeline from the Jones Creek terminal to our ECHO storage facility.

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 September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
Expensed	$ 28.5	$ 16.2	$ 57.4	$ 54.5
Capitalized	16.0	20.1	38.6	60.0
Total	$ 44.5	$ 36.3	$ 96.0	$ 114.5

We expect the cost of our pipeline integrity program, regardless of whether such costs are capitalized or expensed, to approximate $57.0 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 September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
NGL Pipelines & Services	$ 639.6	$ 615.8	$ 1,777.0	$ 1,836.5
Onshore Natural Gas Pipelines & Services	213.4	183.5	601.9	565.5
Onshore Crude Oil Pipelines & Services	146.0	117.6	579.6	252.7
Offshore Pipelines & Services	37.9	40.6	118.1	131.0
Petrochemical & Refined Products Services	117.1	182.1	450.7	437.2
Other Investments (1)	--	--	--	2.4
Total segment gross operating margin	$ 1,154.0	$ 1,139.6	$ 3,527.3	$ 3,225.3

(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 September 30,		For the Nine Months Ended September 30,	
	2013	2012	2013	2012
Total segment gross operating margin	$ 1,154.0	$ 1,139.6	$ 3,527.3	$ 3,225.3
Adjustments to reconcile total segment gross operating margin to operating income:				
Amounts included in operating costs and expenses:				
Depreciation, amortization and accretion	(285.2)	(269.2)	(851.7)	(785.1)
Non-cash asset impairment charges	(15.2)	(43.1)	(53.3)	(57.6)
Gains attributable to asset sales and insurance recoveries	10.2	2.6	68.4	34.1
General and administrative costs	(43.9)	(41.4)	(138.9)	(130.2)
Operating income	819.9	788.5	2,551.8	2,286.5
Other expense, net	(207.7)	(198.2)	(604.2)	(499.4)
Income before income taxes	$ 612.2	$ 590.3	$ 1,947.6	$ 1,787.1

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 September 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 1.2%	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):

		Interest Rate Swap Portfolio Aggregate Fair Value at		
Scenario	Resulting Classification	December 31, 2012	September 30, 2013	October 15, 2013
FV assuming no change in underlying interest rates	*Asset*	$ 28.0	$ 21.1	$ 23.7
FV assuming 10% increase in underlying interest rates	*Asset*	27.2	20.3	22.9
FV assuming 10% decrease in underlying interest rates	*Asset*	28.8	22.0	24.6

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 September 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 September 30, 2013 (volume measures as noted):

	Volume (1)		Accounting
Derivative Purpose	**Current** (2)	**Long-Term** (2)	**Treatment**
Derivatives designated as hedging instruments:			
Natural gas processing:			
Forecasted sales of NGLs (MMBbls)	0.1	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchases of NGLs (MMBbls)	1.0	n/a	Cash flow hedge
Forecasted sales of octane enhancement products (MMBbls)	3.2	0.7	Cash flow hedge
Natural gas marketing:			
Forecasted sales of natural gas (Bcf)	2.4	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)	3.6	n/a	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	7.3	n/a	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products (MMBbls)	0.8	n/a	Cash flow hedge
Forecasted sales of refined products (MMBbls)	1.0	n/a	Cash flow hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	3.7	0.3	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	5.1	0.5	Cash flow hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (Bcf) (3,4)	112.2	23.8	Mark-to-market
Refined products risk management activities (MMBbls) (4)	0.6	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (4)	11.0	0.9	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, May 2014 and October 2016, respectively.

(3) Current and long-term volumes include 52.0 Bcf and 0.3 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 November 1, 2013, our predominant commodity hedging strategies consisted of (i) hedging anticipated future purchases and sales of commodity products associated with transportation, storage and blending activities, (ii) hedging the fair value of commodity products held in inventory, (iii) hedging natural gas processing margins, and (iv) hedging octane enhancement margins. The following information summarizes these hedging strategies:

§ The objective of our anticipated future commodity purchases and sales hedging program is to hedge the margins of certain transportation, storage and blending activities by locking in purchases and sales prices through the use of forward contracts and derivative instruments.

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

§ The objective of our natural gas processing hedging program is to hedge an amount of gross margin associated with these activities. We achieve this objective by executing forward fixed-price sales of a portion of our expected equity NGL production using forward contracts and commodity derivative instruments. For certain natural gas processing contracts, the hedging of expected equity NGL production also involves the purchase of natural gas for plant thermal reduction, which is hedged by executing forward fixed-price purchases using forward contracts and derivative instruments.

§ The objective of our octane enhancement hedging program is to hedge an amount of gross margin associated with these activities. We achieve this objective by executing forward fixed-price sales of a portion of our expected octane enhancement product volumes and forward fixed-price purchases of NGL feedstocks using forward contracts and derivative instruments.

Certain basis swaps, basis spread options and other derivative instruments not designated as hedging instruments are used to manage market risks associated with anticipated purchases and sales of commodity products. 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 accounting guidance, these instruments do not qualify for hedge accounting even though they are effective at managing the risk exposures of the underlying assets. Due to volatility in commodity prices, any non-cash, mark-to-market earnings variability 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):

		Portfolio Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2012**	**September 30, 2013**	**October 15, 2013**
FV assuming no change in underlying commodity prices	*Asset*	$ 7.6	$ 5.1	$ 1.5
FV assuming 10% increase in underlying commodity prices	*Asset (Liability)*	3.0	(1.0)	(5.0)
FV assuming 10% decrease in underlying commodity prices	*Asset*	12.2	11.2	7.9

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):

		Portfolio Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2012**	**September 30, 2013**	**October 15, 2013**
FV assuming no change in underlying commodity prices	*Asset (Liability)*	$ 10.5	$ 3.4	$ (9.9)
FV assuming 10% increase in underlying commodity prices	*Liability*	(27.5)	(50.5)	(65.7)
FV assuming 10% decrease in underlying commodity prices	*Asset*	48.5	57.3	45.9

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

		Portfolio Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2012**	**September 30, 2013**	**October 15, 2013**
FV assuming no change in underlying commodity prices	*Asset (Liability)*	$ (2.0)	$ 9.1	$ 11.9
FV assuming 10% increase in underlying commodity prices	*Liability*	(10.0)	(9.2)	(14.7)
FV assuming 10% decrease in underlying commodity prices	*Asset*	6.1	27.4	38.5

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 third 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*.

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

§ In July 2013, the U.S. Environmental Protection Agency issued a Consent Agreement and Final Order in connection with certain risk management policies at our Mont Belvieu, Texas complex. We believe that the eventual resolution of these matters will result in penalties and other costs of approximately $0.4 million.

§ In September 2013, the New Mexico Environment Department issued a Notice of Violation in connection with certain administrative and monitoring matters involving our South Carlsbad Compressor Station. The eventual resolution of these matters may result in penalties and other costs of approximately $0.1 million.

§ The State of Texas, acting through the District Attorney's Office in Travis County, Texas, has notified us that it is contemplating an action relating to environmental compliance and recordkeeping matters at a tractor-trailer repair and washing facility, located in Brazoria County, Texas, that was previously owned by one of our subsidiaries. Although we sold the facility in connection with the sale of our chemical trucking assets in the first quarter of 2013, we retained liability with respect to such pre-sale compliance matters. We believe that the eventual resolution of these matters will result in monetary sanctions in excess of $0.1 million.

For more information regarding litigation matters, see Note 14 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 nine months ended September 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	--	--
August 2013 (3)	4,126	$ 61.30	--	--

(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.
(3) Of the 16,188 restricted common units that vested in August 2013 and converted to common units, 4,126 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).

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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).
10.4***	2008 Enterprise Products Long-Term Incentive Plan (Third Amendment and Restatement) (incorporated by reference to Annex A to Definitive Proxy Statement filed August 26, 2013).
12.1#	Computation of ratio of earnings to fixed charges for the nine months ended September 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 September 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 September 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 September 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 September 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.
***	Identifies management contract and compensatory plan arrangements.
#	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 November 12, 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

EXHIBIT 12.1

ENTERPRISE PRODUCTS PARTNERS L.P.
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(Dollars in millions)

	For the Nine Months Ended September 30, 2013	For the Year Ended December 31, 2012	2011	2010	2009	2008
Consolidated income	$ 1,901.4	$ 2,428.0	$ 2,088.3	$ 1,383.7	$ 1,140.3	$ 1,145.1
Add: Provision for (benefit from) taxes	46.2	(17.2)	27.2	26.1	25.3	31.0
Less: Equity in earnings from unconsolidated affiliates	(126.1)	(64.3)	(46.4)	(62.0)	(92.3)	(66.2)
Consolidated pre-tax income before equity in earnings from unconsolidated affiliates	1,821.5	2,346.5	2,069.1	1,347.8	1,073.3	1,109.9
Add: Fixed charges	721.1	920.3	879.5	813.4	760.6	717.9
Amortization of capitalized interest	16.9	20.3	17.5	16.8	15.3	13.4
Distributed income of equity investees	187.6	116.7	156.4	191.9	169.3	157.2
Subtotal	2,747.1	3,403.8	3,122.5	2,369.9	2,018.5	1,998.4
Less: Capitalized interest	(95.1)	(116.8)	(106.7)	(47.2)	(53.1)	(90.7)
Net income attributable to noncontrolling interests	(3.4)	(8.1)	(20.5)	(25.5)	(26.4)	(23.0)
Total earnings	$ 2,648.6	$ 3,278.9	$ 2,995.3	$ 2,297.2	$ 1,939.0	$ 1,884.7
Fixed charges:						
Interest expense	$ 604.4	$ 771.8	$ 744.1	$ 741.9	$ 687.3	$ 608.3
Capitalized interest	95.1	116.8	106.7	47.2	53.1	90.7
Interest portion of rental expense	21.6	31.7	28.7	24.3	20.2	18.9
Total	$ 721.1	$ 920.3	$ 879.5	$ 813.4	$ 760.6	$ 717.9
Ratio of earnings to fixed charges	3.7x	3.6x	3.4x	2.8x	2.6x	2.6x

These computations take into account our consolidated operations and the distributed income from our equity method investees. For purposes of these calculations, "earnings" is the amount resulting from adding and subtracting the following items:

Add the following, as applicable:

- consolidated pre-tax income from continuing operations before adjustment for income or loss from equity investees;
- fixed charges;
- amortization of capitalized interest;
- distributed income of equity investees; and
- our share of pre-tax losses of equity investees for which charges arising from guarantees are included in fixed charges.

From the subtotal of the added items, subtract the following, as applicable:

- interest capitalized;
- preference security dividend requirements of consolidated subsidiaries; and
- the noncontrolling interests in pre-tax income of subsidiaries that have not incurred fixed charges.

The term "fixed charges" means the sum of the following: interest expensed and capitalized; amortized premiums, discounts and capitalized expenses related to indebtedness; an estimate of the interest within rental expense; and preference security dividend requirements of consolidated subsidiaries.

EXHIBIT 31.1

SARBANES-OXLEY SECTION 302 CERTIFICATION

I, Michael A. Creel, certify that:

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

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

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

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

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

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

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

Date: November 12, 2013

/s/ Michael A. Creel

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

EXHIBIT 31.2

SARBANES-OXLEY SECTION 302 CERTIFICATION

I, W. Randall Fowler, certify that:

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

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

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

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

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

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

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

Date: November 12, 2013

/s/ W. Randall Fowler

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

EXHIBIT 32.1

SARBANES-OXLEY SECTION 906 CERTIFICATION

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

In connection with this quarterly report of Enterprise Products Partners L.P. (the "Registrant") on Form 10-Q for the quarterly period ended September 30, 2013 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Michael A. Creel, Chief Executive Officer of Enterprise Products Holdings LLC, the General Partner of the Registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

/s/ Michael A. Creel

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

Date: November 12, 2013

EXHIBIT 32.2

SARBANES-OXLEY SECTION 906 CERTIFICATION

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

In connection with this quarterly report of Enterprise Products Partners L.P. (the "Registrant") on Form 10-Q for the quarterly period ended September 30, 2013 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, W. Randall Fowler, Chief Financial Officer of Enterprise Products Holdings LLC, the General Partner of the Registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

/s/ W. Randall Fowler

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

Date: November 12, 2013