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 March 31, 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 910,781,527 common units and 4,520,431 Class B units (which generally vote together with the common units) of Enterprise Products Partners L.P. outstanding at April 30, 2013. Our common units trade on the New York Stock Exchange under the ticker symbol "EPD."

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PART I. FINANCIAL INFORMATION.

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

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

ASSETS	March 31, 2013	December 31, 2012
Current assets:		
Cash and cash equivalents	$ 1,280.3	$ 16.1
Restricted cash	68.1	4.3
Accounts receivable – trade, net of allowance for doubtful accounts of $11.9 at March 31, 2013 and $13.2 at December 31, 2012	4,502.2	4,350.9
Accounts receivable – related parties	2.7	2.5
Inventories	1,159.1	1,088.4
Prepaid and other current assets	355.9	380.9
Total current assets	7,368.3	5,843.1
Property, plant and equipment, net	25,222.5	24,846.4
Investments in unconsolidated affiliates	1,679.0	1,394.6
Intangible assets, net of accumulated amortization of $1,075.7 at March 31, 2013 and $1,050.0 at December 31, 2012	1,539.8	1,566.8
Goodwill	2,086.1	2,086.8
Other assets	205.7	196.7
Total assets	$ 38,101.4	$ 35,934.4
LIABILITIES AND EQUITY		
Current liabilities:		
Current maturities of debt (see Note 9)	$ 1,150.0	$ 1,546.6
Accounts payable – trade	790.9	764.5
Accounts payable – related parties	93.1	127.1
Accrued product payables	4,911.5	4,476.2
Accrued interest	185.7	300.8
Other current liabilities	387.4	540.5
Total current liabilities	7,518.6	7,755.7
Long-term debt (see Note 9)	16,393.7	14,655.2
Deferred tax liabilities	16.1	22.5
Other long-term liabilities	182.8	205.0
Commitments and contingencies (see Note 14)		
Equity: (see Note 10)		
Partners' equity:		
Limited partners:		
Common units (910,805,527 units outstanding at March 31, 2013 and 898,813,337 units outstanding at December 31, 2012)	14,162.1	13,439.6
Class B units (4,520,431 units outstanding at March 31, 2013 and December 31, 2012)	118.5	118.5
Total limited partners' equity	14,280.6	13,558.1
Accumulated other comprehensive loss	(398.1)	(370.4)
Total partners' equity	13,882.5	13,187.7
Noncontrolling interests	107.7	108.3
Total equity	13,990.2	13,296.0
Total liabilities and equity	$ 38,101.4	$ 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 March 31, 2013	For the Three Months Ended March 31, 2012
Revenues:		
Third parties	$ 11,377.2	$ 11,221.7
Related parties	5.9	30.8
Total revenues (see Note 11)	11,383.1	11,252.5
Costs and expenses:		
Operating costs and expenses:		
Third parties	10,206.2	10,318.8
Related parties	214.2	148.4
Total operating costs and expenses	10,420.4	10,467.2
General and administrative costs:		
Third parties	19.7	23.6
Related parties	29.8	22.7
Total general and administrative costs	49.5	46.3
Total costs and expenses (see Note 11)	10,469.9	10,513.5
Equity in income of unconsolidated affiliates	44.5	9.9
Operating income	957.7	748.9
Other income (expense):		
Interest expense	(195.9)	(186.5)
Interest income	0.2	0.3
Other, net	(0.3)	58.4
Total other expense, net	(196.0)	(127.8)
Income before income taxes	761.7	621.1
Benefit from (provision for) income taxes	(6.4)	34.4
Net income	755.3	655.5
Net income attributable to noncontrolling interests (see Note 10)	(1.8)	(4.2)
Net income attributable to limited partners	$ 753.5	$ 651.3
Earnings per unit: (see Note 13)		
Basic earnings per unit	$ 0.85	$ 0.76
Diluted earnings per unit	$ 0.83	$ 0.73

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

	For the Three Months Ended March 31,	
	2013	2012
Net income	$ 755.3	$ 655.5
Other comprehensive income (loss):		
Cash flow hedges:		
Commodity derivative instruments:		
Changes in fair value of cash flow hedges	(47.6)	(59.6)
Reclassification of losses to net income	7.3	22.0
Interest rate derivative instruments:		
Changes in fair value of cash flow hedges	6.7	28.9
Reclassification of losses to net income	5.9	2.7
Total cash flow hedges	(27.7)	(6.0)
Change in funded status of pension and postretirement plans, net of tax	--	(1.2)
Proportionate share of other comprehensive income of unconsolidated affiliate	--	1.0
Change in fair value of available-for-sale equity securities	--	15.8
Total other comprehensive income (loss)	(27.7)	9.6
Comprehensive income	727.6	665.1
Comprehensive income attributable to noncontrolling interests	(1.8)	(4.2)
Comprehensive income attributable to limited partners	$ 725.8	$ 660.9

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 Three Months Ended March 31, 2013	2012
Operating activities:		
Net income	$ 755.3	$ 655.5
Reconciliation of net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	292.0	266.1
Non-cash asset impairment charges (see Note 4)	11.0	5.4
Equity in income of unconsolidated affiliates	(44.5)	(9.9)
Distributions received from unconsolidated affiliates	51.3	27.0
Gains attributable to asset sales and insurance recoveries (see Note 16)	(63.9)	(55.8)
Deferred income tax benefit	(6.5)	(67.2)
Changes in fair market value of derivative instruments	12.3	(15.4)
Net effect of changes in operating accounts (see Note 16)	(8.0)	(201.1)
Other operating activities	0.9	0.3
Net cash flows provided by operating activities	999.9	604.9
Investing activities:		
Capital expenditures	(631.6)	(973.1)
Contributions in aid of construction costs	8.7	5.0
Increase in restricted cash	(63.8)	(15.0)
Investments in unconsolidated affiliates	(291.4)	(50.6)
Proceeds from asset sales and insurance recoveries (see Note 16)	130.5	998.2
Other investing activities	0.4	--
Cash used in investing activities	(847.2)	(35.5)
Financing activities:		
Borrowings under debt agreements	6,174.6	1,396.6
Repayments of debt	(4,826.6)	(1,300.0)
Debt issuance costs	(17.3)	(7.1)
Monetization of interest rate derivative instruments (see Note 4)	(168.8)	(77.6)
Cash distributions paid to limited partners (see Note 10)	(577.6)	(530.4)
Cash distributions paid to noncontrolling interests (see Note 10)	(2.4)	(6.6)
Cash contributions from noncontrolling interests (see Note 10)	--	4.9
Net cash proceeds from issuance of common units	554.1	32.8
Other financing activities	(24.5)	(13.5)
Cash provided by (used in) financing activities	1,111.5	(500.9)
Net change in cash and cash equivalents	1,264.2	68.5
Cash and cash equivalents, January 1	16.1	19.8
Cash and cash equivalents, March 31	$ 1,280.3	$ 88.3

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	753.5	--	1.8	755.3
Cash distributions paid to limited partners	(577.6)	--	--	(577.6)
Cash distributions paid to noncontrolling interests	--	--	(2.4)	(2.4)
Net cash proceeds from issuance of common units	554.1	--	--	554.1
Amortization of fair value of equity-based awards	17.1	--	--	17.1
Cash flow hedges	--	(27.7)	--	(27.7)
Other	(24.6)	--	--	(24.6)
Balance, March 31, 2013	$ 14,280.6	$ (398.1)	$ 107.7	$ 13,990.2

	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	651.3	--	4.2	655.5
Cash distributions paid to limited partners	(530.4)	--	--	(530.4)
Cash distributions paid to noncontrolling interests	--	--	(6.6)	(6.6)
Cash contributions from noncontrolling interests	--	--	4.9	4.9
Net cash proceeds from issuance of common units	32.8	--	--	32.8
Amortization of fair value of equity-based awards	15.6	--	--	15.6
Cash flow hedges	--	(6.0)	--	(6.0)
Change in fair value of available-for-sale equity securities	--	15.8	--	15.8
Other	(13.5)	(0.2)	1.1	(12.6)
Balance, March 31, 2012	$ 12,620.6	$ (341.8)	$ 109.5	$ 12,388.3

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

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

KEY REFERENCES USED IN THESE
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

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

References to "EPCO" mean Enterprise Products Company, a Texas corporation, and its privately held affiliates. A majority of the outstanding voting capital stock of EPCO is owned of record by a voting trust, the current trustees ("EPCO Trustees") of which are: (i) Ms. Williams, who also serves as Chairman of EPCO; (ii) Dr. Cunningham, who also serves as a Vice Chairman of EPCO; and (iii) Mr. Bachmann, who also serves as the President and Chief Executive Officer ("CEO") of EPCO. Each of the EPCO Trustees is also a director of EPCO.

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

Note 1. Partnership Operations, Organization and Basis of Presentation

General

We are a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "EPD." We were formed in April 1998 to own and operate certain natural gas liquids ("NGLs") related businesses of EPCO and are now a leading North American provider of midstream energy services to producers and consumers of natural gas, NGLs, crude oil, refined products and petrochemicals.

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

We have five reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services; and (v) Petrochemical & Refined Products Services. All activities included in our former sixth reportable business segment, Other Investments, ceased on January 18, 2012, which was the date we discontinued using the equity method to account for our previously held investment in Energy Transfer Equity L.P. (together with its subsidiaries, "Energy Transfer Equity") (see "Liquidation of Investment in Energy Transfer Equity" under Note 7).

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

Note 2. General Accounting Matters

Our results of operations for the three months ended March 31, 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 presented:

	For the Three Months Ended March 31,	
	2013	2012
Balance at beginning of period	$ 13.2	$ 13.4
Charged to costs and expenses	--	0.1
Deductions	(1.3)	(0.5)
Balance at end of period	$ 11.9	$ 13.0

Contingencies

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

We accrue an undiscounted liability for those contingencies where the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. We do not record a contingent liability when the likelihood of loss is probable but the amount cannot be reasonably estimated or when it is believed to be only reasonably possible or remote.

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

See Note 4 for additional information regarding our derivative instruments.

Estimates

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

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

Income Tax Benefit

During the first quarter of 2012, we recognized an overall net income tax benefit of $34.4 million, 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, partially offset by accruals for the Texas Margin Tax. The $46.5 million net income tax benefit 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.

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 presented:

	For the Three Months Ended March 31,	
	2013	2012
Gain on sales of available-for-sale securities of Energy Transfer Equity (1)	$ --	$ 53.3
Distribution income from Energy Transfer Equity	--	4.1
Other	(0.3)	1.0
Total	$ (0.3)	$ 58.4

(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 accounts as margin in support of our commodity derivative instruments portfolio and related physical natural gas, crude oil and NGL purchases. Additional cash may be restricted to maintain this portfolio as commodity prices fluctuate or deposit requirements change. At March 31, 2013 and December 31, 2012, our restricted cash amounts were $68.1 million and $4.3 million, respectively. See Note 4 for information regarding derivative instruments and hedging activities.

Note 3. Equity-based Awards

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

	For the Three Months Ended March 31,	
	2013	2012
Restricted common unit awards	$ 16.6	$ 14.8
Unit option awards	0.4	0.7
Other (1)	0.2	0.9
Total	$ 17.2	$ 16.4

(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 period. Liability-classified awards are settled in cash upon vesting.

At March 31, 2013, EPCO's significant long-term incentive plans applicable to us were the Enterprise Products 1998 Long-Term Incentive Plan ("1998 Plan") and the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan ("2008 Plan"). In addition, there were unvested awards outstanding under an inactive plan, the Enterprise Products 2006 TPP Long-Term Incentive Plan. After giving effect to awards granted under the 1998 Plan and 2008 Plan through March 31, 2013, a total of 877,049 and 4,247,819 additional common units could be issued under these plans, respectively.

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 presented:

	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)	1,723,576	$ 57.11
Vested (3)	(939,226)	$ 43.42
Forfeited	(59,460)	$ 43.13
Restricted common units at March 31, 2013	4,618,376	$ 46.38

(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 $98.4 million based on a grant date market price of our common units of $57.11 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 presented:

	For the Three Months Ended March 31, 2013	For the Three Months Ended March 31, 2012
Cash distributions paid to restricted common unitholders	$ 2.6	$ 2.4
Total intrinsic value of restricted common unit awards that vested during period	$ 52.4	$ 32.6

For the EPCO group of companies, the unrecognized compensation cost associated with restricted common unit awards was an aggregate $128.7 million at March 31, 2013, of which our allocated share of the cost is currently estimated to be $118.4 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.2 years.

Unit Option Awards

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 presented:

	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	(646,000)	$ 30.83		
Unit option awards at March 31, 2013	2,115,140	$ 26.36	2.1	$ 27.3
Options exercisable at March 31, 2013	30,000	$ 30.93	0.8	$ 0.9

(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 presented:

	For the Three Months Ended March 31, 2013	2012
Total intrinsic value of unit option awards exercised during period	$ 16.4	$ 14.0
Cash received from EPCO in connection with the exercise of unit option awards	$ 9.5	$ 10.2
Unit option award-related cash reimbursements to EPCO	$ 16.4	$ 14.0

For the EPCO group of companies, the unrecognized compensation cost associated with unit option awards was an aggregate $0.5 million at March 31, 2013, of which our allocated share of the cost is currently estimated to be $0.4 million. We expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 0.8 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. Forward starting swaps perform a similar function except that they are associated with interest rates underlying anticipated future issuances of debt.

The following table summarizes our portfolio of interest rate swaps at March 31, 2013:

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

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

At December 31, 2012, our portfolio of forward starting interest rate swaps consisted of 16 derivative instruments having a combined 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, which resulted in cash payments totaling $168.8 million. These losses are a component of accumulated other comprehensive income and are being amortized to earnings (as an increase in interest expense) over the forecasted hedge period of ten years using the effective interest method.

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

Commodity Hedging Activities

The prices of natural gas, NGLs, crude oil, refined products and certain petrochemical products are subject to fluctuations in response to changes in supply and demand, market conditions and a variety of additional factors that are beyond our control. In order to manage such price risks, we enter into commodity derivative instruments such as physical forward contracts, futures contracts, fixed-for-float swaps, basis swaps and option contracts. The following table summarizes our portfolio of commodity derivative instruments outstanding at March 31, 2013 (volume measures as noted):

	Volume (1)		**Accounting**
Derivative Purpose	**Current** (2)	**Long-Term** (2)	**Treatment**
Derivatives designated as hedging instruments:			
Octane enhancement:			
Forecasted purchases of NGLs (MMBbls)	1.5	n/a	Cash flow hedge
Forecasted sales of octane enhancement products (MMBbls)	3.2	n/a	Cash flow hedge
Natural gas marketing:			
Forecasted sales of natural gas (Bcf)	0.1	n/a	Cash flow hedge
Natural gas storage inventory management activities (Bcf)	1.9	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	3.4	n/a	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	6.5	n/a	Cash flow hedge
Refined products marketing:			
Refined products inventory management activities (MMBbls)	0.1	n/a	Fair value hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	3.9	n/a	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	8.8	n/a	Cash flow hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (Bcf) (3,4)	162.7	25.9	Mark-to-market
Refined products risk management activities (MMBbls) (4)	0.5	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (4)	3.7	n/a	Mark-to-market

(1) Volume for derivatives designated as hedging instruments reflects the total amount of volumes hedged whereas volume for derivatives not designated as hedging instruments reflects the absolute value of derivative notional volumes.
(2) The maximum term for derivatives designated as cash flow hedges, derivatives designated as fair value hedges and derivatives not designated as hedging instruments is March 2014, March 2014 and October 2015, respectively.
(3) Current volumes include 89.5 Bcf of physical derivative instruments that are predominantly priced at a market-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 March 31, 2013, our predominant commodity hedging strategies consisted of (i) hedging anticipated future contracted sales of NGLs, crude oil, and related products associated with volumes held in inventory and (ii) hedging the fair value of natural gas and refined products in inventory. The following information summarizes these hedging strategies:

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

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

At March 31, 2013, we did not have any hedges in place with respect to gross margins associated with our future natural gas processing activities. Management continues to evaluate market conditions to determine the appropriate timing to implement this strategy, if at all, during 2013.

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

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

	Asset Derivatives				Liability Derivatives			
	March 31, 2013		December 31, 2012		March 31, 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	$ 16.1	Other current assets	$ 19.6	Other current liabilities	$ --	Other current liabilities	$ 175.4
Interest rate derivatives	Other assets	22.3	Other assets	25.6	Other liabilities	--	Other liabilities	--
Total interest rate derivatives		38.4		45.2		--		175.4
Commodity derivatives	Other current assets	45.8	Other current assets	45.3	Other current liabilities	78.3	Other current liabilities	35.4
Commodity derivatives	Other assets	--	Other assets	--	Other liabilities	--	Other liabilities	0.5
Total commodity derivatives		45.8		45.3		78.3		35.9
Total derivatives designated as hedging instruments		$ 84.2		$ 90.5		$ 78.3		$ 211.3
Derivatives not designated as hedging instruments								
Interest rate derivatives	Other current assets	$ --	Other current assets	$ --	Other current liabilities	$ 12.1	Other current liabilities	$ 12.2
Interest rate derivatives	Other assets	--	Other assets	--	Other liabilities	2.6	Other liabilities	5.0
Total interest rate derivatives		--		--		14.7		17.2
Commodity derivatives	Other current assets	6.0	Other current assets	15.7	Other current liabilities	7.8	Other current liabilities	8.9
Commodity derivatives	Other assets	0.3	Other assets	0.6	Other liabilities	1.0	Other liabilities	0.7
Total commodity derivatives		6.3		16.3		8.8		9.6
Total derivatives not designated as hedging instruments		$ 6.3		$ 16.3		$ 23.5		$ 26.8

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

Offsetting of Financial Assets and Derivative Assets

	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Amounts of Assets Presented in the Balance Sheet	Gross Amounts Not Offset in the Balance Sheet: Financial Instruments	Gross Amounts Not Offset in the Balance Sheet: Cash Collateral Received	Amounts That Would Have Been Presented On Net Basis
	(i)	(ii)	(iii) = (i) – (ii)	(iv)	(iv)	(v) = (iii) – (iv)
As of March 31, 2013:						
Commodity derivatives	$ 52.1	$ --	$ 52.1	$ (52.0)	$ --	$ 0.1
As of December 31, 2012:						
Commodity derivatives	$ 61.6	$ --	$ 61.6	$ (38.7)	$ (15.2)	$ 7.7

Offsetting of Financial Liabilities and Derivative Liabilities

	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Balance Sheet	Amounts of Liabilities Presented in the Balance Sheet	Gross Amounts Not Offset in the Balance Sheet: Financial Instruments	Gross Amounts Not Offset in the Balance Sheet: Cash Collateral Paid	Amounts That Would Have Been Presented On Net Basis
	(i)	(ii)	(iii) = (i) – (ii)	(iv)	(iv)	(v) = (iii) – (iv)
As of March 31, 2013:						
Commodity derivatives	$ 87.1	$ --	$ 87.1	$ (52.0)	$ (24.3)	$ 10.8
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 or maintenance margins. Any amounts associated with derivative prepayments or initial margins that are not influenced by the derivative asset or liability amounts or those that are determined solely on their volumetric notional amounts are excluded from this table.

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

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

Derivatives in Fair Value Hedging Relationships	Location	Gain (Loss) Recognized in Income on Derivative For the Three Months Ended March 31, 2013	2012
Interest rate derivatives	Interest expense	$ (3.5)	$ (1.5)
Commodity derivatives	Revenue	(0.7)	0.7
Total		$ (4.2)	$ (0.8)

Derivatives in Fair Value Hedging Relationships	Location	Gain (Loss) Recognized in Income on Hedged Item For the Three Months Ended March 31, 2013	2012
Interest rate derivatives	Interest expense	$ 3.4	$ 1.1
Commodity derivatives	Revenue	(6.7)	0.4
Total		$ (3.3)	$ 1.5

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 presented.

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 presented:

Derivatives in Cash Flow Hedging Relationships	Change in Value Recognized in Other Comprehensive Income (Loss) on Derivative (Effective Portion) For the Three Months Ended March 31, 2013	2012
Interest rate derivatives	$ 6.7	$ 28.9
Commodity derivatives – Revenue (1)	(47.6)	(39.6)
Commodity derivatives – Operating costs and expenses (1)	--	(20.0)
Total	$ (40.9)	$ (30.7)

(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 March 31, 2013	2012
Interest rate derivatives	Interest expense	$ (5.9)	$ (2.7)
Commodity derivatives	Revenue	(7.7)	(10.0)
Commodity derivatives	Operating costs and expenses	0.4	(12.0)
Total		$ (13.2)	$ (24.7)

Derivatives in Cash Flow Hedging Relationships	Location	Gain (Loss) Recognized in Income on Derivative (Ineffective Portion)	
		For the Three Months Ended March 31,	
		2013	2012
Commodity derivatives	Operating costs and expenses	$ --	$ 0.3
Total		$ --	$ 0.3

Over the next twelve months, we expect to reclassify $31.1 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 $30.1 million of losses attributable to commodity derivative instruments from accumulated other comprehensive loss to earnings as a decrease in revenue.

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

Derivatives Not Designated as Hedging Instruments	Location	Gain (Loss) Recognized in Income on Derivative	
		For the Three Months Ended March 31,	
		2013	2012
Interest rate derivatives	Interest expense	$ 0.1	$ (2.2)
Commodity derivatives	Revenue	(5.3)	20.8
Commodity derivatives	Operating costs and expenses	--	(2.8)
Total		$ (5.2)	$ 15.8

Fair Value Measurements

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

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

Recurring Fair Value Measurements

The following table sets forth, by level within the fair value hierarchy, the carrying values of our financial assets and liabilities at March 31, 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.

	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 March 31, 2013
Financial assets:				
Interest rate derivatives	$ --	$ 38.4	$ --	$ 38.4
Commodity derivatives	16.3	35.8	--	52.1
Total	$ 16.3	$ 74.2	$ --	$ 90.5
Financial liabilities:				
Interest rate derivatives	$ --	$ 14.7	$ --	$ 14.7
Commodity derivatives	39.1	47.4	0.6	87.1
Total	$ 39.1	$ 62.1	$ 0.6	$ 101.8

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 presented:

	Location	For the Three Months Ended March 31, 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 (loss)	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

(1) There were unrealized gains of $0.9 million and $0.1 million included in these amounts for the three months ended March 31, 2013 and 2012, respectively.

The following table provides quantitative information about our recurring Level 3 fair value measurements at March 31, 2013:

	Fair Value				
	Financial Assets	Financial Liabilities	Valuation Techniques	Unobservable Input	Range
Commodity derivatives – Crude oil	$ --	$ 0.6	Discounted cash flow	Forward commodity prices	$95.75-$112.88/barrel

We believe forward commodity prices are the most significant unobservable inputs in determining our Level 3 recurring fair value measurements at March 31, 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

We recorded $11.0 million of non-cash asset impairment charges during the three months ended March 31, 2013 related to the abandonment of assets classified as property, plant and equipment. Of this amount, $10.0 million relates to the abandonment of certain refined products terminal and storage assets located in southeast Texas and $1.0 million relates to an underground storage cavern taken out of service at our Hobbs NGL fractionation facility.

We recorded $5.4 million of non-cash asset impairment charges during the three months ended March 31, 2012. Of this amount, $5.1 million relates to the abandonment of certain NGL fractionation assets and a pipeline segment located in Texas classified as property, plant and equipment. The remaining $0.3 million relates to the sale of certain marine transportation assets, which were classified as assets held-for-sale (Level 3) at March 31, 2012.

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

	For the Three Months Ended March 31,	
	2013	**2012**
NGL Pipelines & Services	$ 1.0	$ 5.1
Petrochemical & Refined Products Services	10.0	0.3
Total	$ 11.0	$ 5.4

Other Fair Value Information

The carrying amounts of cash and cash equivalents (including restricted cash balances), accounts receivable 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 $19.54 billion and $18.42 billion at March 31, 2013 and December 31, 2012, respectively. The aggregate carrying value of these debt obligations was $17.53 billion and $16.18 billion at March 31, 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:

	March 31, 2013	December 31, 2012
NGLs	$ 531.4	$ 594.3
Petrochemicals and refined products	443.3	304.5
Crude oil	165.6	119.4
Natural gas	18.8	70.2
Total	$ 1,159.1	$ 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 March 31,	
	2013	2012
Cost of sales (1)	$ 9,692.5	$ 9,665.8
Lower of cost or market adjustments	$ 2.7	$ 5.9

(1) Cost of sales is a component of "Operating costs and expenses," as presented on our Unaudited Condensed Statements of Consolidated Operations. Quarter-to-quarter 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	March 31, 2013	December 31, 2012
Plants, pipelines and facilities (1)	3-45 (6)	$ 26,016.1	$ 25,382.4
Underground and other storage facilities (2)	5-40 (7)	1,869.5	1,826.3
Platforms and facilities (3)	20-31	666.9	635.2
Transportation equipment (4)	3-10	133.4	136.2
Marine vessels (5)	15-30	703.2	695.0
Land		175.5	167.2
Construction in progress		1,990.5	2,113.1
Total		31,555.1	30,955.4
Less accumulated depreciation		6,332.6	6,109.0
Property, plant and equipment, net		$ 25,222.5	$ 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 presented:

	For the Three Months Ended March 31,	
	2013	2012
Depreciation expense (1)	$ 245.4	$ 212.0
Capitalized interest (2)	31.6	30.6

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

In January 2013, we sold certain trucking assets devoted to chemical transportation activities to a third party for a net $29.5 million in cash. As a result of this transaction, we recognized a $0.5 million loss from the sale of these assets.

In March 2013, we sold the Stratton Ridge-to-Mont Belvieu segment of the Seminole Pipeline, along with a related storage cavern, to a third party for $86.9 million in cash. As a result, net income for the first quarter of 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.

Asset Retirement Obligations

Property, plant and equipment at March 31, 2013 and December 31, 2012 includes $42.2 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 three months ended March 31, 2013:

ARO liability balance, December 31, 2012	$ 105.2
Liabilities settled	(1.3)
Revisions in estimated cash flows	(2.8)
Accretion expense	1.5
ARO liability balance, March 31, 2013	$ 102.6

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

Remainder of 2013	2014	2015	2016	2017
$ 4.7	$ 6.5	$ 6.3	$ 6.6	$ 7.2

Certain of our unconsolidated affiliates have AROs recorded at March 31, 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 March 31, 2013	March 31, 2013	December 31, 2012
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C.	13.1%	$ 29.9	$ 29.6
K/D/S Promix, L.L.C.	50%	46.2	46.9
Baton Rouge Fractionators LLC	32.2%	20.3	20.2
Skelly-Belvieu Pipeline Company, L.L.C.	50%	38.7	38.2
Texas Express Pipeline LLC	35%	196.2	144.4
Texas Express Gathering LLC	45%	25.4	20.9
Front Range Pipeline LLC	33.3%	55.4	24.4
Onshore Natural Gas Pipelines & Services:			
White River Hub, LLC	50%	24.6	24.9
Onshore Crude Oil Pipelines & Services:			
Seaway Crude Pipeline Company LLC	50%	463.6	341.4
Eagle Ford Pipeline LLC	50%	196.7	152.4
Offshore Pipelines & Services:			
Poseidon Oil Pipeline Company, L.L.C. ("Poseidon")	36%	46.2	47.3
Cameron Highway Oil Pipeline Company	50%	212.2	220.0
Deepwater Gateway, L.L.C.	50%	88.8	90.0
Neptune Pipeline Company, L.L.C.	25.7%	45.6	46.8
Southeast Keathley Canyon Pipeline Company L.L.C.	50%	116.2	74.9
Petrochemical & Refined Products Services:			
Baton Rouge Propylene Concentrator, LLC	30%	8.2	8.5
Centennial Pipeline LLC ("Centennial")	50%	61.9	60.8
Other (1)	Various	2.9	3.0
Total		$ 1,679.0	$ 1,394.6

(1) Other unconsolidated affiliates include a 50% interest in a propylene pipeline extending from Mont Belvieu, Texas to La Porte, Texas and a 25% interest in a company that provides logistics communications solutions between petroleum pipelines and their customers.

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

	For the Three Months Ended March 31,	
	2013	2012
NGL Pipelines & Services	$ 3.9	$ 5.2
Onshore Natural Gas Pipelines & Services	1.0	1.4
Onshore Crude Oil Pipelines & Services	36.6	0.5
Offshore Pipelines & Services	6.4	6.9
Petrochemical & Refined Products Services	(3.4)	(6.5)
Other Investments	--	2.4
Total	$ 44.5	$ 9.9

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

	March 31, 2013	December 31, 2012
NGL Pipelines & Services	$ 28.6	$ 28.9
Onshore Crude Oil Pipelines & Services	18.3	18.5
Offshore Pipelines & Services	13.3	13.6
Petrochemical & Refined Products Services	2.7	2.7
Total	$ 62.9	$ 63.7

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

	For the Three Months Ended March 31, 2013	For the Three Months Ended March 31, 2012
NGL Pipelines & Services	$ 0.3	$ 0.2
Onshore Crude Oil Pipelines & Services	0.2	0.2
Offshore Pipelines & Services	0.3	0.3
Petrochemical & Refined Products Services	--	0.1
Other Investments	--	0.3
Total	$ 0.8	$ 1.1

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 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 an additional 3,569,232 Energy Transfer Equity common units through March 31, 2012, which generated cash proceeds of $150.8 million and gains on these sales totaling $25.8 million. The $53.3 million of aggregate gains on the first quarter of 2012 sales are a component of "Other income" on our Unaudited Condensed Statements of Consolidated Operations. We liquidated our remaining investment in Energy Transfer Equity by April 27, 2012.

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

Summarized Income Statement Information of Unconsolidated Affiliates

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

	Summarized Income Statement Information for the Three Months Ended					
	March 31, 2013			March 31, 2012		
	Revenues	Operating Income (Loss)	Net Income (Loss)	Revenues	Operating Income (Loss)	Net Income (Loss)
NGL Pipelines & Services	$ 83.4	$ 15.3	$ 15.2	$ 110.9	$ 27.0	$ 27.0
Onshore Natural Gas Pipelines & Services	2.9	1.9	1.9	30.9	2.6	2.6
Onshore Crude Oil Pipelines & Services	78.5	71.7	67.9	12.3	0.8	0.8
Offshore Pipelines & Services	42.3	18.0	17.3	41.1	19.1	18.4
Petrochemical & Refined Products Services	6.0	(3.9)	(5.8)	5.4	(9.4)	(11.4)

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 March 31, 2013.

Note 8. Intangible Assets and Goodwill

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

	March 31, 2013			December 31, 2012		
	Gross Value	Accumulated Amortization	Carrying Value	Gross Value	Accumulated Amortization	Carrying Value
NGL Pipelines & Services:						
Customer relationship intangibles	$ 340.8	$ (152.3)	$ 188.5	$ 340.8	$ (147.6)	$ 193.2
Contract-based intangibles	284.6	(162.1)	122.5	284.6	(157.2)	127.4
Segment total	625.4	(314.4)	311.0	625.4	(304.8)	320.6
Onshore Natural Gas Pipelines & Services:						
Customer relationship intangibles	1,163.6	(257.8)	905.8	1,163.6	(250.0)	913.6
Contract-based intangibles	466.1	(316.4)	149.7	466.1	(311.8)	154.3
Segment total	1,629.7	(574.2)	1,055.5	1,629.7	(561.8)	1,067.9
Onshore Crude Oil Pipelines & Services:						
Customer relationship intangibles	10.7	(5.2)	5.5	10.7	(4.9)	5.8
Contract-based intangibles	0.4	(0.3)	0.1	0.4	(0.3)	0.1
Segment total	11.1	(5.5)	5.6	11.1	(5.2)	5.9
Offshore Pipelines & Services:						
Customer relationship intangibles	203.9	(141.6)	62.3	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	(142.0)	63.1	205.1	(138.9)	66.2
Petrochemical & Refined Products Services:						
Customer relationship intangibles	104.3	(34.7)	69.6	104.3	(33.4)	70.9
Contract-based intangibles	39.9	(4.9)	35.0	41.2	(5.9)	35.3
Segment total	144.2	(39.6)	104.6	145.5	(39.3)	106.2
Total all segments	$ 2,615.5	$ (1,075.7)	$ 1,539.8	$ 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 presented:

	For the Three Months Ended March 31,	
	2013	2012
NGL Pipelines & Services	$ 9.6	$ 10.2
Onshore Natural Gas Pipelines & Services	12.4	15.8
Onshore Crude Oil Pipelines & Services	0.3	0.2
Offshore Pipelines & Services	3.0	2.6
Petrochemical & Refined Products Services	1.6	3.5
Total	$ 26.9	$ 32.3

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
$ 79.3	$ 96.1	$ 90.1	$ 91.8	$ 95.8

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 three months ended March 31, 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
Reclassification to assets held for sale	--	--	--	--	(0.7)	(0.7)
Balance at March 31, 2013 (1)	$ 341.2	$ 296.3	$ 311.2	$ 82.1	$ 1,055.3	$ 2,086.1

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

Note 9. Debt Obligations

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

	March 31, 2013	December 31, 2012
EPO senior debt obligations:		
Commercial Paper Notes, fixed-rates ranging from 0.28% to 0.50%	$ --	$ 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	400.0
Senior Notes U, 5.90% fixed-rate, due April 2013	237.6	237.6
Senior Notes O, 9.75% fixed-rate, due January 2014	500.0	500.0
Senior Notes G, 5.60% fixed-rate, due October 2014	650.0	650.0
Senior Notes I, 5.00% fixed-rate, due March 2015	250.0	250.0
Senior Notes X, 3.70% fixed-rate, due June 2015	400.0	400.0
Senior Notes 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
$3.5 Billion Multi-Year Revolving Credit Facility, variable-rate, due September 2016	--	--
Senior Notes L, 6.30% fixed-rate, due September 2017	800.0	800.0
Senior Notes V, 6.65% fixed-rate, due April 2018	349.7	349.7
Senior Notes N, 6.50% fixed-rate, due January 2019	700.0	700.0
Senior Notes Q, 5.25% fixed-rate, due January 2020	500.0	500.0
Senior Notes Y, 5.20% fixed-rate, due September 2020	1,000.0	1,000.0
Senior Notes 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	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 (1)	35.8	39.3
Unamortized discounts, net of premiums	(42.6)	(38.0)
Other	17.8	21.2
Total other, non-principal amounts	11.0	22.5
Less current maturities of debt (2)	(1,150.0)	(1,546.6)
Total long-term debt	$ 16,393.7	$ 14,655.2

(1) See Note 4 for information regarding our interest rate hedging activities.
(2) We expect to refinance the current maturities of our debt obligations at or prior to their maturity.

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The following table presents contractually scheduled maturities of our consolidated debt obligations outstanding at March 31, 2013 for the next five years, and in total thereafter:

		Scheduled Maturities of Debt					
	Total	Remainder of 2013	2014	2015	2016	2017	After 2017
Senior Notes	$ 16,000.0	$ 650.0	$ 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	$ 650.0	$ 1,150.0	$ 1,300.0	$ 750.0	$ 800.0	$ 12,882.7

Apart from those items discussed below and routine fluctuations in the balance of our 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.

Parent-Subsidiary Guarantor Relationships

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.

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 March 31, 2013, EPO did not have any letters of credit outstanding related to its commodity derivative instruments.

Lender Financial Covenants

We were in compliance with the financial covenants of our consolidated debt agreements at March 31, 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 three months ended March 31, 2013:

	Range of Interest Rates Paid	Weighted-Average Interest Rate Paid
EPO $3.5 Billion Multi-Year Revolving Credit Facility	1.50% to 1.51%	1.50%

Note 10. Equity and Distributions

Partners' equity reflects the various classes of limited partner interests (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 three months ended March 31, 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 DRIP and EUPP	1,275,229	--	1,275,229
Common units issued in connection with the vesting of unit options	168,628	--	168,628
Common units issued in connection with the vesting of restricted common unit awards	939,226	(939,226)	--
Restricted common unit awards issued	--	1,723,576	1,723,576
Forfeiture of restricted common unit awards	--	(59,460)	(59,460)
Acquisition and cancellation of treasury units in connection with the vesting of equity-based awards	(315,783)	--	(315,783)
Number of units outstanding at March 31, 2013	906,187,151	4,618,376	910,805,527

We may issue additional equity or debt securities to assist us in meeting our future liquidity and capital spending requirements. We have a universal shelf registration statement (the "2010 Shelf") on file with the SEC. The 2010 Shelf allows Enterprise Products Partners L.P. and EPO (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).

We have a registration statement on file with the SEC covering the issuance of up to $1.0 billion of our common units in amounts, at prices and on terms to be determined by market conditions and other factors at the time of such offerings. Pursuant to this "at-the-market" program, we may sell common units under an equity distribution agreement between Enterprise Products Partners L.P. and certain broker-dealers from time-to-time by means of ordinary brokers' transactions through the NYSE at market prices, in block transactions or as otherwise agreed to with the broker-dealer parties to the agreement. During the three months ended March 31, 2013, we did not issue any common units under this program. After taking into account the aggregate sale price of common units issued under this program through May 8, 2013, we have the capacity to issue additional common units under this program up to an aggregate sale price of $743.6 million.

We also have registration statements on file with the SEC collectively authorizing the issuance of up to 70,000,000 of our common units in connection with a distribution reinvestment plan (or "DRIP"). The DRIP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of our common units they own by reinvesting the quarterly cash distributions they would otherwise receive from us into the purchase of additional new common units. We issued 1,243,360 common units under our DRIP during the three months ended March 31, 2013, which generated net proceeds of $65.7 million. During the three months ended March 31, 2012, we issued 667,095 common units, which generated net proceeds of $31.8 million. After taking into account the number of common units issued under the DRIP through March 31, 2013, we may issue an additional 22,249,932 common units under this plan.

In January 2013, affiliates of privately held EPCO, which own our general partner and approximately 37.1% of our limited partner interests at March 31, 2013, expressed their willingness to purchase at least $100 million of our common units during 2013 principally through our DRIP. In February 2013, the EPCO affiliates reinvested $25.0 million, resulting in the issuance of 473,188 common units under our DRIP (this amount being a component of the 1,243,360 common units issued in total under the DRIP in February 2013). In May 2013, the EPCO affiliates reinvested an additional $25.0 million under the DRIP.

In addition to the DRIP, we have a registration statement on file with the SEC authorizing the issuance of up to 440,879 of our common units in connection with an employee unit purchase plan (or "EUPP"). We issued 31,869 common units under our EUPP during the three months ended March 31, 2013, which generated net proceeds of $1.8 million. During the three months ended March 31, 2012, we issued 24,841 common units, which generated net proceeds of $1.2 million. After taking into account the number of common units issued under the EUPP through March 31, 2013, we may issue an additional 264,167 common units under this plan.

The net cash proceeds we received from the issuance of common units during the three months ended March 31, 2013 were used to temporarily reduce amounts outstanding under EPO's revolving credit facility and commercial paper program and for general company purposes.

A total of 939,226 restricted common unit awards granted to employees of EPCO vested and converted to common units during the three months ended March 31, 2013. Of this amount, 315,783 were sold back to us by employees in connection with their minimum statutory withholding tax requirements. The total cost of these treasury unit purchases was approximately $17.7 million. We cancelled such treasury units immediately upon acquisition. For additional information regarding our equity-based awards, see Note 3.

Class B units. In October 2009, we issued 4,520,431 Class B units to a privately held affiliate of EPCO in connection with the TEPPCO Merger. The Class B units are entitled to vote together with our common units as a single class on partnership matters and generally have the same rights and privileges as our common units, except that the Class B units are not entitled to receive regular quarterly cash distributions until they automatically convert into an equal number of common units. The Class B units will automatically convert into the same number of distribution-bearing common units on the date immediately following the distribution payment date for the second quarter of 2013, which is expected to occur in August 2013.

Accumulated Other Comprehensive Income (Loss)

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

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

	Gains and Losses on Cash Flow Hedges				
	Commodity Derivative Instruments	Interest Rate Derivative Instruments	Foreign Currency Translation Adjustment	Postretirement Benefit Plans	Total
Balance, December 31, 2012	$ 10.1	$ (383.0)	$ 1.7	$ 0.8	$ (370.4)
Other comprehensive income before reclassifications	(47.6)	6.7	--	--	(40.9)
Amounts reclassified from accumulated other comprehensive income	7.3	5.9	--	--	13.2
Total other comprehensive income	(40.3)	12.6	--	--	(27.7)
Balance, March 31, 2013	$ (30.2)	$ (370.4)	$ 1.7	$ 0.8	$ (398.1)

The following table presents reclassifications out of accumulated other comprehensive income into net income during the three months ended March 31, 2013:

	Location	
Losses (gains) on cash flow hedges:		
Interest rate derivatives	Interest expense	$ 5.9
Commodity derivatives	Revenue	7.7
Commodity derivatives	Operating costs and expenses	(0.4)
Total		$ 13.2

Noncontrolling Interests

Noncontrolling interests as presented on our unaudited 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 and Wilprise Pipeline Company LLC.

Cash Distributions

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

	Distribution Per Common Unit	Record Date	Payment Date
2013			
1st Quarter	$ 0.6700	04/30/13	05/07/13

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, the 4,520,431 Class B units will automatically convert into the same number of distribution-bearing common units on the date immediately following the distribution payment date for the second quarter of 2013, which is expected to occur in August 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.

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

	For the Three Months Ended March 31,	
	2013	2012
Revenues	$ 11,383.1	$ 11,252.5
Less: Operating costs and expenses	(10,420.4)	(10,467.2)
Add: Equity in income of unconsolidated affiliates	44.5	9.9
Depreciation, amortization and accretion recorded in operating costs and expenses	276.8	254.6
Non-cash asset impairment charges recorded in operating costs and expenses	11.0	5.4
Gains attributable to asset sales and insurance recoveries recorded in operating costs and expenses	(63.9)	(2.5)
Total segment gross operating margin	$ 1,231.1	$ 1,052.7

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 March 31,	
	2013	2012
Total segment gross operating margin	$ 1,231.1	$ 1,052.7
Adjustments to reconcile total segment gross operating margin to operating income:		
Amounts included in operating costs and expenses:		
Depreciation, amortization and accretion	(276.8)	(254.6)
Non-cash asset impairment charges	(11.0)	(5.4)
Gains attributable to asset sales and insurance recoveries	63.9	2.5
General and administrative costs	(49.5)	(46.3)
Operating income	957.7	748.9
Other expense, net	(196.0)	(127.8)
Income before income taxes	$ 761.7	$ 621.1

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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 Totals
Revenues from third parties:								
Three months ended March 31, 2013	$ 3,950.7	$ 874.2	$ 4,793.2	$ 40.5	$ 1,718.6	$ --	$ --	$ 11,377.2
Three months ended March 31, 2012	4,354.1	804.9	4,473.6	54.4	1,534.7	--	--	11,221.7
Revenues from related parties:								
Three months ended March 31, 2013	0.3	3.5	--	2.1	--	--	--	5.9
Three months ended March 31, 2012	0.4	28.7	--	1.7	--	--	--	30.8
Intersegment and intrasegment revenues:								
Three months ended March 31, 2013	2,709.0	256.2	2,024.7	2.0	422.1	--	(5,414.0)	--
Three months ended March 31, 2012	2,818.2	223.7	1,730.9	3.3	439.9	--	(5,216.0)	--
Total revenues:								
Three months ended March 31, 2013	6,660.0	1,133.9	6,817.9	44.6	2,140.7	--	(5,414.0)	11,383.1
Three months ended March 31, 2012	7,172.7	1,057.3	6,204.5	59.4	1,974.6	--	(5,216.0)	11,252.5
Equity in income (loss) of unconsolidated affiliates:								
Three months ended March 31, 2013	3.9	1.0	36.6	6.4	(3.4)	--	--	44.5
Three months ended March 31, 2012	5.2	1.4	0.5	6.9	(6.5)	2.4	--	9.9
Gross operating margin:								
Three months ended March 31, 2013	592.5	190.8	236.4	40.5	170.9	--	--	1,231.1
Three months ended March 31, 2012	654.9	206.2	39.3	52.1	97.8	2.4	--	1,052.7
Property, plant and equipment, net: (see Note 6)								
At March 31, 2013	9,059.1	8,942.0	1,359.0	1,323.5	2,548.4	--	1,990.5	25,222.5
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 March 31, 2013	412.1	24.6	660.3	509.0	73.0	--	--	1,679.0
At December 31, 2012	324.6	24.9	493.8	479.0	72.3	--	--	1,394.6
Intangible assets, net: (see Note 8)								
At March 31, 2013	311.0	1,055.5	5.6	63.1	104.6	--	--	1,539.8
At December 31, 2012	320.6	1,067.9	5.9	66.2	106.2	--	--	1,566.8
Goodwill: (see Note 8)								
At March 31, 2013	341.2	296.3	311.2	82.1	1,055.3	--	--	2,086.1
At December 31, 2012	341.2	296.3	311.2	82.1	1,056.0	--	--	2,086.8
Segment assets:								
At March 31, 2013	10,123.4	10,318.4	2,336.1	1,977.7	3,781.3	--	1,990.5	30,527.4
At December 31, 2012	9,481.2	10,339.2	2,196.8	1,970.3	3,794.0	--	2,113.1	29,894.6

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

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

	For the Three Months Ended March 31, 2013	2012
NGL Pipelines & Services:		
Sales of NGLs and related products	$ 3,665.6	$ 4,115.3
Midstream services	285.4	239.2
Total	3,951.0	4,354.5
Onshore Natural Gas Pipelines & Services:		
Sales of natural gas	639.5	572.6
Midstream services	238.2	261.0
Total	877.7	833.6
Onshore Crude Oil Pipelines & Services:		
Sales of crude oil	4,742.8	4,447.6
Midstream services	50.4	26.0
Total	4,793.2	4,473.6
Offshore Pipelines & Services:		
Sales of natural gas	0.1	0.1
Sales of crude oil	2.3	1.4
Midstream services	40.2	54.6
Total	42.6	56.1
Petrochemical & Refined Products Services:		
Sales of petrochemicals and refined products	1,547.2	1,351.2
Midstream services	171.4	183.5
Total	1,718.6	1,534.7
Total consolidated revenues	$ 11,383.1	$ 11,252.5
Consolidated costs and expenses		
Operating costs and expenses:		
Cost of sales	$ 9,692.5	$ 9,665.8
Other operating costs and expenses (1)	504.0	543.9
Depreciation, amortization and accretion	276.8	254.6
Gains attributable to asset sales and insurance recoveries	(63.9)	(2.5)
Non-cash asset impairment charges	11.0	5.4
General and administrative costs	49.5	46.3
Total consolidated costs and expenses	$ 10,469.9	$ 10,513.5

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

Quarter-to-quarter 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.

Note 12. Related Party Transactions

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

	For the Three Months Ended March 31, 2013	2012
Revenues – related parties:		
Unconsolidated affiliates	$ 5.9	$ 30.8
Costs and expenses – related parties:		
EPCO and affiliates	$ 212.7	$ 166.0
Unconsolidated affiliates	31.3	5.1
Total	$ 244.0	$ 171.1

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

	March 31, 2013	December 31, 2012
Accounts receivable - related parties:		
Unconsolidated affiliates	$ 2.7	$ 2.5
Accounts payable - related parties:		
EPCO and affiliates	$ 61.9	$ 102.4
Unconsolidated affiliates	31.2	24.7
Total	$ 93.1	$ 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 March 31, 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
339,604,069 (1)	37.1%

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

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 three months ended March 31, 2013 and 2012, we paid EPCO and its privately held affiliates cash distributions totaling $197.1 million and $183.7 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 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 presented:

	For the Three Months Ended March 31, 2013	For the Three Months Ended March 31, 2012
Operating costs and expenses	$ 181.1	$ 142.7
General and administrative expenses	31.6	23.3
Total costs and expenses	$ 212.7	$ 166.0

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 March 31, 2013	For the Three Months Ended March 31, 2012
BASIC EARNINGS PER UNIT		
Numerator:		
Net income attributable to limited partners	$ 753.5	$ 651.3
Denominator:		
Weighted-average number of distribution-bearing common units outstanding	881.6	856.6
Basic earnings per unit:		
Net income attributable to limited partners	$ 0.85	$ 0.76
DILUTED EARNINGS PER UNIT		
Numerator:		
Net income attributable to limited partners	$ 753.5	$ 651.3
Denominator:		
Weighted-average number of units outstanding:		
Distribution-bearing common units	881.6	856.6
Class B units	4.5	4.5
Designated Units	23.7	26.1
Incremental option units	1.2	1.5
Total	911.0	888.7
Diluted earnings per unit:		
Net income attributable to limited partners	$ 0.83	$ 0.73

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 March 31, 2013 and December 31, 2012, our accruals for litigation contingencies were $4.7 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 balance of our revolving credit facility and commercial paper notes, the issuance of senior notes 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 $22.0 million and $22.4 million during the three months ended March 31, 2013 and 2012, 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 March 31, 2013, our contingent claims against such parties were $45.8 million and claims against us were $43.3 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 expect to forego windstorm coverage for our Gulf of Mexico offshore assets during the upcoming 2013 hurricane season, which extends from June through November. The combination of increasingly high deductibles and proposed premiums resulted in such coverage being uneconomic to us. Although EPCO's coverage may not provide any windstorm coverage for offshore assets during the upcoming annual policy period that begins on June 1, 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.

We received $8.8 million of nonrefundable insurance proceeds during the three months ended March 31, 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. We remain in negotiation with our insurance carriers regarding the remaining West Storage claims, which are currently estimated at $91.9 million. Operating income for the first quarter of 2013 includes $8.8 million of gains related to these insurance recoveries. To the extent that additional non-refundable 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 presented:

	For the Three Months Ended March 31, 2013	For the Three Months Ended March 31, 2012
Decrease (increase) in:		
Accounts receivable – trade	$ (163.5)	$ (25.6)
Accounts receivable – related parties	(0.2)	30.0
Inventories	84.1	135.6
Prepaid and other current assets	8.5	14.1
Other assets	2.1	(16.4)
Increase (decrease) in:		
Accounts payable – trade	(32.8)	63.4
Accounts payable – related parties	(34.0)	(132.2)
Accrued product payables	261.7	(195.7)
Accrued interest	(115.2)	(103.6)
Other current liabilities	(0.2)	40.7
Other liabilities	(18.5)	(11.4)
Net effect of changes in operating accounts	$ (8.0)	$ (201.1)

We incurred liabilities for construction in progress that had not been paid at March 31, 2013 and December 31, 2012 of $296.9 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 presented:

	For the Three Months Ended March 31, 2013	For the Three Months Ended March 31, 2012
Sale of Energy Transfer Equity common units (see Note 7)	$ --	$ 975.9
Sale of Stratton Ridge-to-Mont Belvieu segment of Seminole Pipeline (see Note 6)	86.9	--
Sale of chemical trucking assets (see Note 6)	29.5	--
Insurance recoveries attributable to West Storage claims (see Note 15)	8.8	--
Other cash proceeds	5.3	22.3
Total	$ 130.5	$ 998.2

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

	For the Three Months Ended March 31,	
	2013	**2012**
Sale of Energy Transfer Equity common units (see Note 7) (1)	$ --	$ 53.3
Sale of Stratton Ridge-to-Mont Belvieu segment of Seminole Pipeline (see Note 6) (2)	52.5	--
Sale of chemical trucking assets (see Note 6) (2)	(0.5)	--
Insurance recoveries attributable to West Storage claims (see Note 15) (2)	8.8	--
Other gains, net (2)	3.1	2.5
Total	$ 63.9	$ 55.8

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

Note 17. Condensed Consolidating Financial Information

EPO conducts substantially all of our business. Currently, we have no independent operations and no material assets outside those of EPO.

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

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

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Balance Sheet
March 31, 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	$ 1,314.9	$ 39.0	$ (5.7)	$ 1,348.2	$ 0.2	$ --	$ 1,348.4
Accounts receivable – trade, net	1,574.6	2,934.0	(6.4)	4,502.2	--	--	4,502.2
Accounts receivable – related parties	266.4	1,557.2	(1,797.2)	26.4	--	(23.7)	2.7
Inventories	927.7	232.4	(1.0)	1,159.1	--	--	1,159.1
Prepaid and other current assets	117.5	243.3	(5.3)	355.5	0.4	--	355.9
Total current assets	4,201.1	5,005.9	(1,815.6)	7,391.4	0.6	(23.7)	7,368.3
Property, plant and equipment, net	1,746.3	23,474.2	2.0	25,222.5	--	--	25,222.5
Investments in unconsolidated affiliates	29,249.7	2,047.5	(29,618.2)	1,679.0	13,906.0	(13,906.0)	1,679.0
Intangible assets, net	78.1	1,461.7	--	1,539.8	--	--	1,539.8
Goodwill	458.9	1,627.2	--	2,086.1	--	--	2,086.1
Other assets	135.5	76.2	(6.2)	205.5	0.2	--	205.7
Total assets	$ 35,869.6	$ 33,692.7	$ (31,438.0)	$ 38,124.3	$ 13,906.8	$ (13,929.7)	$ 38,101.4
LIABILITIES AND EQUITY							
Current liabilities:							
Current maturities of debt	$ 1,137.6	$ 12.4	$ --	$ 1,150.0	$ --	$ --	$ 1,150.0
Accounts payable – trade	231.5	565.1	(5.7)	790.9	--	--	790.9
Accounts payable – related parties	1,759.6	131.8	(1,798.9)	92.5	24.3	(23.7)	93.1
Accrued product payables	2,177.4	2,739.8	(5.7)	4,911.5	--	--	4,911.5
Accrued interest	185.0	0.7	--	185.7	--	--	185.7
Other current liabilities	77.1	315.4	(5.2)	387.3	--	0.1	387.4
Total current liabilities	5,568.2	3,765.2	(1,815.5)	7,517.9	24.3	(23.6)	7,518.6
Long-term debt	16,378.8	14.9	--	16,393.7	--	--	16,393.7
Deferred tax liabilities	5.3	16.4	(6.2)	15.5	--	0.6	16.1
Other long-term liabilities	9.9	172.9	--	182.8	--	--	182.8
Commitments and contingencies							
Equity:							
Partners' and other owners' equity	13,907.4	29,649.2	(29,674.2)	13,882.4	13,882.5	(13,882.4)	13,882.5
Noncontrolling interests	--	74.1	57.9	132.0	--	(24.3)	107.7
Total equity	13,907.4	29,723.3	(29,616.3)	14,014.4	13,882.5	(13,906.7)	13,990.2
Total liabilities and equity	$ 35,869.6	$ 33,692.7	$ (31,438.0)	$ 38,124.3	$ 13,906.8	$ (13,929.7)	$ 38,101.4

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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 March 31, 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	$ 7,355.5	$ 7,440.4	$ (3,412.8)	$ 11,383.1	$ --	$ --	$ 11,383.1
Costs and expenses:							
Operating costs and expenses	7,143.9	6,689.2	(3,412.7)	10,420.4	--	--	10,420.4
General and administrative costs	4.7	44.6	--	49.3	0.2	--	49.5
Total costs and expenses	7,148.6	6,733.8	(3,412.7)	10,469.7	0.2	--	10,469.9
Equity in income of unconsolidated affiliates	746.7	51.2	(753.4)	44.5	753.7	(753.7)	44.5
Operating income	953.6	757.8	(753.5)	957.9	753.5	(753.7)	957.7
Other income (expense):							
Interest expense	(195.3)	(0.6)	--	(195.9)	--	--	(195.9)
Other, net	0.1	(0.2)	--	(0.1)	--	--	(0.1)
Total other expense, net	(195.2)	(0.8)	--	(196.0)	--	--	(196.0)
Income before income taxes	758.4	757.0	(753.5)	761.9	753.5	(753.7)	761.7
Provision for income taxes	(5.1)	(1.0)	--	(6.1)	--	(0.3)	(6.4)
Net income	753.3	756.0	(753.5)	755.8	753.5	(754.0)	755.3
Net loss (income) attributable to noncontrolling interests	--	(0.5)	(2.0)	(2.5)	--	0.7	(1.8)
Net income attributable to entity	$ 753.3	$ 755.5	$ (755.5)	$ 753.3	$ 753.5	$ (753.3)	$ 753.5

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
Three Months Ended March 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
Revenues	$ 7,639.8	$ 7,158.5	$ (3,545.8)	$ 11,252.5	$ --	$ --	$ 11,252.5
Costs and expenses:							
Operating costs and expenses	7,409.8	6,603.6	(3,546.2)	10,467.2	--	--	10,467.2
General and administrative costs	15.4	30.7	--	46.1	0.2	--	46.3
Total costs and expenses	7,425.2	6,634.3	(3,546.2)	10,513.3	0.2	--	10,513.5
Equity in income of unconsolidated affiliates	594.5	78.4	(663.0)	9.9	651.5	(651.5)	9.9
Operating income	809.1	602.6	(662.6)	749.1	651.3	(651.5)	748.9
Other income (expense):							
Interest expense	(185.6)	(0.9)	--	(186.5)	--	--	(186.5)
Other, net	0.1	58.6	--	58.7	--	--	58.7
Total other expense, net	(185.5)	57.7	--	(127.8)	--	--	(127.8)
Income before income taxes	623.6	660.3	(662.6)	621.3	651.3	(651.5)	621.1
Benefit from income taxes	27.0	7.4	--	34.4	--	--	34.4
Net income	650.6	667.7	(662.6)	655.7	651.3	(651.5)	655.5
Net loss (income) attributable to noncontrolling interests	--	(44.4)	39.7	(4.7)	--	0.5	(4.2)
Net income attributable to entity	$ 650.6	$ 623.3	$ (622.9)	$ 651.0	$ 651.3	$ (651.0)	$ 651.3

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Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Comprehensive Income
Three Months Ended March 31, 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	$ 753.0	$ 728.4	$ (753.4)	$ 728.0	$ 725.8	$ (726.2)	$ 727.6
Comprehensive income attributable to noncontrolling interests	--	(0.5)	(2.0)	(2.5)	--	0.7	(1.8)
Comprehensive income attributable to entity	$ 753.0	$ 727.9	$ (755.4)	$ 725.5	$ 725.8	$ (725.5)	$ 725.8

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Comprehensive Income
Three Months Ended March 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
Comprehensive income	$ 679.8	$ 648.1	$ (662.6)	$ 665.3	$ 651.3	$ (651.5)	$ 665.1
Comprehensive income attributable to noncontrolling interests	--	(44.4)	39.7	(4.7)	--	0.5	(4.2)
Comprehensive income attributable to entity	$ 679.8	$ 603.7	$ (622.9)	$ 660.6	$ 651.3	$ (651.0)	$ 660.9

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Cash Flows
Three Months Ended March 31, 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	$ 753.3	$ 756.0	$ (753.5)	$ 755.8	$ 753.5	$ (754.0)	$ 755.3
Reconciliation of net income to net cash flows provided by operating activities:							
Depreciation, amortization and accretion	33.8	258.2	--	292.0	--	--	292.0
Equity in income of unconsolidated affiliates	(746.7)	(51.2)	753.4	(44.5)	(753.7)	753.7	(44.5)
Distributions received from unconsolidated affiliates	1,173.7	50.3	(1,172.7)	51.3	577.6	(577.6)	51.3
Net effect of changes in operating accounts and other operating activities	(76.8)	16.2	6.5	(54.1)	23.2	(23.3)	(54.2)
Net cash flows provided by operating activities	1,137.3	1,029.5	(1,166.3)	1,000.5	600.6	(601.2)	999.9
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(62.1)	(560.8)	--	(622.9)	--	--	(622.9)
Proceeds from asset sales and insurance recoveries	--	130.5	--	130.5	--	--	130.5
Other investing activities	(958.6)	(203.9)	807.7	(354.8)	(552.5)	552.5	(354.8)
Cash used in investing activities	(1,020.7)	(634.2)	807.7	(847.2)	(552.5)	552.5	(847.2)
Financing activities:							
Borrowings under debt agreements	6,174.6	--	--	6,174.6	--	--	6,174.6
Repayments of debt	(4,809.2)	(17.4)	--	(4,826.6)	--	--	(4,826.6)
Cash distributions paid to partners	(601.2)	(1,175.1)	1,175.1	(601.2)	(577.6)	601.2	(577.6)
Cash distributions paid to noncontrolling interests	--	--	(2.4)	(2.4)	--	--	(2.4)
Net cash proceeds from issuance of common units	--	--	--	--	554.1	--	554.1
Cash contributions from owners	552.5	807.7	(807.7)	552.5	--	(552.5)	--
Other financing activities	(186.0)	--	--	(186.0)	(24.6)	--	(210.6)
Cash provided by (used in) financing activities	1,130.7	(384.8)	365.0	1,110.9	(48.1)	48.7	1,111.5
Net change in cash and cash equivalents	1,247.3	10.5	6.4	1,264.2	--	--	1,264.2
Cash and cash equivalents, January 1	--	28.0	(12.1)	15.9	0.2	--	16.1
Cash and cash equivalents, March 31	$ 1,247.3	$ 38.5	$ (5.7)	$ 1,280.1	$ 0.2	$ --	$ 1,280.3

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

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Cash Flows
Three Months Ended March 31, 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	$ 650.6	$ 667.7	$ (662.6)	$ 655.7	$ 651.3	$ (651.5)	$ 655.5
Reconciliation of net income to net cash flows provided by operating activities:							
Depreciation, amortization and accretion	33.0	233.4	(0.3)	266.1	--	--	266.1
Equity in income of unconsolidated affiliates	(594.5)	(78.4)	663.0	(9.9)	(651.5)	651.5	(9.9)
Distributions received from unconsolidated affiliates	10.0	25.8	(8.8)	27.0	531.6	(531.6)	27.0
Net effect of changes in operating accounts and other operating activities	(489.4)	335.8	(191.4)	(345.0)	11.5	(0.3)	(333.8)
Net cash flows provided by operating activities	(390.3)	1,184.3	(200.1)	593.9	542.9	(531.9)	604.9
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(16.0)	(952.1)	--	(968.1)	--	--	(968.1)
Proceeds from asset sales and insurance recoveries	976.1	22.1	--	998.2	--	--	998.2
Other investing activities	(38.9)	(39.2)	12.5	(65.6)	(31.8)	31.8	(65.6)
Cash used in investing activities	921.2	(969.2)	12.5	(35.5)	(31.8)	31.8	(35.5)
Financing activities:							
Borrowings under debt agreements	1,396.6	--	--	1,396.6	--	--	1,396.6
Repayments of debt	(1,290.5)	(9.5)	--	(1,300.0)	--	--	(1,300.0)
Cash distributions paid to partners	(531.6)	(208.0)	208.0	(531.6)	(530.4)	531.6	(530.4)
Cash distributions paid to noncontrolling interests	--	(4.4)	(2.2)	(6.6)	--	--	(6.6)
Cash contributions from noncontrolling interests	--	--	4.9	4.9	--	--	4.9
Net cash proceeds from issuance of common units	--	--	--	--	32.8	--	32.8
Cash contributions from owners	31.8	17.3	(17.3)	31.8	--	(31.8)	--
Other financing activities	(84.6)	--	(0.1)	(84.7)	(13.5)	--	(98.2)
Cash provided by (used in) financing activities	(478.3)	(204.6)	193.3	(489.6)	(511.1)	499.8	(500.9)
Net change in cash and cash equivalents	52.6	10.5	5.7	68.8	--	(0.3)	68.5
Cash and cash equivalents, January 1	9.7	21.3	(11.2)	19.8	--	--	19.8
Cash and cash equivalents, March 31	$ 62.3	$ 31.8	$ (5.5)	$ 88.6	$ --	$ (0.3)	$ 88.3

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

For the three months ended March 31, 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 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 the Gulf of Mexico with domestic consumers and international markets. Our midstream energy operations include: natural gas gathering, treating, processing, transportation and storage; NGL transportation, fractionation, storage, and import and export terminals (including LPG); crude oil gathering and transportation, storage and terminals; offshore production platforms; petrochemical and refined products transportation and services; and a marine transportation business that operates primarily on the U.S. inland and Intracoastal Waterway systems and in the Gulf of Mexico. Our assets include approximately 50,000 miles of onshore and offshore pipelines; 200 MMBbls of storage capacity for NGLs, petrochemicals, refined products and crude oil; and 14 Bcf of natural gas storage capacity. In addition, our asset portfolio includes 24 natural gas processing plants, 21 NGL and propylene fractionators, six offshore hub platforms located in the Gulf of Mexico, a butane isomerization complex, NGL import and export terminals, and octane enhancement and high-purity isobutylene production facilities.

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

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

Significant Recent Developments

The following information highlights significant commercial and operational developments since January 1, 2013 through the date of this filing (May 8, 2013). For information regarding recent offerings of our equity and debt securities, see "Liquidity and Capital Resources" within this Item 2.

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

On May 2, 2013, we announced plans to significantly expand our crude oil storage and distribution infrastructure serving the Southeast Texas refinery market. This planned expansion includes approximately 4.0 MMBbls of combined new crude oil storage capacity at our Enterprise Crude Houston ("ECHO") storage facility and a smaller second facility and 55 miles of associated pipelines to directly connect ECHO with several major refineries in the Southeast Texas market. The expansion would be completed in phases with final completion expected in the fourth quarter of 2014.

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

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

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 Enterprise Aegis Pipeline or "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 multiple petrochemical customers in Texas and Louisiana. The Aegis Pipeline is expected to begin commercial operations in 2014.

Operations Begin at Expanded LPG Export Facility

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

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

Results of Operations

Summarized Consolidated Income Statement Data

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

	For the Three Months Ended March 31, 2013	For the Three Months Ended March 31, 2012
Revenues	$ 11,383.1	$ 11,252.5
Costs and expenses:		
Operating costs and expenses:		
Cost of sales	9,692.5	9,665.8
Other operating costs and expenses	504.0	543.9
Depreciation, amortization and accretion	276.8	254.6
Gains attributable to asset sales and insurance recoveries	(63.9)	(2.5)
Non-cash asset impairment charges	11.0	5.4
Total operating costs and expenses	10,420.4	10,467.2
General and administrative costs	49.5	46.3
Total costs and expenses	10,469.9	10,513.5
Equity in income of unconsolidated affiliates	44.5	9.9
Operating income	957.7	748.9
Interest expense	(195.9)	(186.5)
Other, net	(0.1)	58.7
Benefit from (provision for) income taxes	(6.4)	34.4
Net income	755.3	655.5
Net income attributable to noncontrolling interests	(1.8)	(4.2)
Net income attributable to limited partners	$ 753.5	$ 651.3

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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 March 31,	
	2013	2012
NGL Pipelines & Services:		
Sales of NGLs and related products	$ 3,665.6	$ 4,115.3
Midstream services	285.4	239.2
Total	3,951.0	4,354.5
Onshore Natural Gas Pipelines & Services:		
Sales of natural gas	639.5	572.6
Midstream services	238.2	261.0
Total	877.7	833.6
Onshore Crude Oil Pipelines & Services:		
Sales of crude oil	4,742.8	4,447.6
Midstream services	50.4	26.0
Total	4,793.2	4,473.6
Offshore Pipelines & Services:		
Sales of natural gas	0.1	0.1
Sales of crude oil	2.3	1.4
Midstream services	40.2	54.6
Total	42.6	56.1
Petrochemical & Refined Products Services:		
Sales of petrochemicals and refined products	1,547.2	1,351.2
Midstream services	171.4	183.5
Total	1,718.6	1,534.7
Total consolidated revenues	$ 11,383.1	$ 11,252.5

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 presented:

	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

(1) Natural gas prices are based on Henry-Hub Inside FERC commercial index prices as reported by Platts, which is a division of The McGraw-Hill Companies.
(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.

Quarter-to-quarter 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 quarter-to-quarter changes in key commodity prices affecting our results of operations:

§ The weighted-average indicative market price for NGLs (based on prices for such products at Mont Belvieu, Texas, which is the primary industry hub for domestic NGL production) was $1.02 per gallon during the first quarter of 2013 versus $1.35 per gallon during the first quarter of 2012 – a 24% quarter-to-quarter decrease. Ethane accounts for the largest volume of NGLs extracted from the natural gas stream (approximately 40% of NGLs produced from natural gas processing and fractionation operations). As a result of producers allocating more of their capital budgets to developing NGL-rich natural gas shale plays and their success in extracting such resources, ethane production has increased more rapidly than the ethylene industry's current capability to consume the increase in supplies. This oversupply situation has contributed to a significant decrease in average ethane prices since the beginning of 2012 – a 54% decrease for the first quarter of 2013 when compared to the first quarter 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 and 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 at 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 $3.34 per MMBtu during the first quarter of 2013 versus $2.72 per MMBtu during the first quarter of 2012 – a 23% quarter-to-quarter increase. The increase in the natural gas price is primarily due to higher demand for natural gas as a heating fuel during the first quarter of 2013 compared to the first quarter of 2012. Natural gas prices (Henry Hub) remain well below their 2011 and 2010 averages of $4.04 per MMBtu and $4.39 per MMBtu, respectively.

§ The market price of WTI crude oil (as measured on the NYMEX) averaged $94.37 per barrel during the first quarter of 2013 compared to $102.93 per barrel during the first quarter of 2012 – an 8% quarter-to-quarter decrease. As a result of our recent crude oil pipeline infrastructure improvements, we have greater access to U.S. Gulf Coast refiners. Typically, these refining customers purchase crude oil based on LLS prices, which are significantly higher than WTI prices. Although down quarter-to-quarter, LLS prices averaged $113.93 per barrel during the first quarter of 2013 compared to $119.59 per barrel during the first quarter of 2012.

A decrease in our consolidated marketing revenues due to lower energy commodity sales prices may not generate a decrease in gross operating margin or cash available for distributions, since corresponding 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 prices.

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 quarter-to-quarter income statement amounts and the primary drivers of such changes.

Revenues for the first quarter of 2013 increased $130.6 million compared to the first quarter of 2012. Revenues from crude oil marketing increased $296.1 million quarter-to-quarter and those from natural gas marketing increased $66.9 million quarter-to-quarter, with both increases primarily due to higher sales prices during the first quarter of 2013. Revenues from crude oil marketing increased quarter-to-quarter as we were able to use our recent crude oil pipeline infrastructure improvements, which include our Eagle Ford assets, to realize higher prices for our crude oil inventories by selling to U.S. Gulf Coast refining customers. Typically, Gulf Coast crude oil prices are higher than those that can be realized by selling at the Cushing hub. Revenues from natural gas marketing increased quarter-to-quarter primarily due to the 23% increase in natural gas prices noted previously. Revenues from the sale of petrochemicals and refined products increased $196.0 million quarter-to-quarter primarily due to higher sales volumes by our octane enhancement facility and refined products marketing activities. Our octane enhancement facility experienced periods of downtime during the first quarter of 2012 which adversely affected its sales volumes. Revenues from refined products marketing increased quarter-to-quarter primarily due to an increase in volumes sold to markets in the northeastern U.S. Revenues from NGL marketing for the first quarter of 2013 decreased $449.7 million when compared to the first quarter of 2012 primarily due to lower NGL prices. As previously noted, weighted-average indicative market prices for NGLs declined 24% quarter-to-quarter. Lastly, revenues from midstream asset services increased $21.3 million quarter-to-quarter primarily due to contributions from our recently constructed assets in the Eagle Ford Shale supply basin (e.g., our new Yoakum natural gas processing plant and Eagle Ford NGL and crude oil pipelines).

In total, operating costs and expenses for the first quarter of 2013 decreased $46.8 million when compared to the first quarter of 2012. Cost of sales for the first quarter of 2013 increased $26.7 million over the first quarter of 2012. The cost of sales associated with our crude oil marketing increased $219.5 million quarter-to-quarter and those associated with natural gas marketing increased $15.7 million primarily due to higher purchase prices. The increase in cost of sales associated with our crude oil marketing activities is primarily due to increased purchases of LLS-priced crude oil volumes along the U.S. Gulf Coast. The increase in cost of sales associated with our natural gas marketing activities is attributable to higher natural gas prices quarter-to-quarter. Cost of sales attributable to our petrochemical and refined products marketing activities for the first quarter of 2013 increased $75.2 million when compared to the first quarter of 2012. Of this increase, $44.4 million is attributable to higher sales volumes during the first quarter of 2013 by our octane enhancement facility compared to the first quarter of 2012. The remainder of the $75.2 million quarter-to-quarter increase is primarily due to higher refined products sales to customers in the northeastern U.S. Cost of sales associated with NGLs and related products for the first quarter of 2013 decreased $283.7 million when compared to the first quarter of 2012 primarily due to the decline in NGL prices discussed previously. Other operating costs and expenses for the first quarter of 2013 decreased $39.9 million quarter-to-quarter primarily due to lower repair and maintenance and pipeline integrity expenses.

Depreciation, amortization and accretion in operating costs and expenses increased $22.2 million quarter-to-quarter primarily due to new assets that were under construction being placed into service since the first quarter of 2012 (e.g., our Eagle Ford expansion projects).

Gains attributable to asset sales and insurance recoveries in operating costs and expenses increased $61.4 million during the first quarter of 2013 when compared to the first quarter of 2012. These amounts are a component of operating costs and expenses. In March 2013, we sold the Stratton Ridge-to-Mont Belvieu segment of the Seminole Pipeline, along with a related storage cavern, to a third party for $86.9 million in cash. As a result, net income for the first quarter of 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 pipeline that we own. In addition, we received $8.8 million of nonrefundable insurance proceeds during the first quarter of 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. To the extent that non-refundable insurance proceeds related to this incident are received, we record gains equal to such proceeds. We remain in negotiation with our insurance carriers regarding the remaining West Storage claims, which are currently estimated at $91.9 million.

Non-cash asset impairment charges for the first quarter of 2013 increased $5.6 million when compared to the first quarter of 2012 primarily due to the abandonment of certain refined products terminal and storage assets located in southeast Texas in the first quarter of 2013.

General and administrative costs for the first quarter of 2013 increased $3.2 million when compared to the first quarter of 2012 primarily due to higher employee compensation expenses.

Equity income from our unconsolidated affiliates for the first quarter of 2013 increased $34.6 million when compared to the first quarter of 2012. Equity earnings from our investments in crude oil pipeline joint ventures increased $36.4 million quarter-to-quarter primarily due to the completion of expansion capital projects during the second quarter of 2012.

Interest expense for the first quarter of 2013 increased $9.4 million when compared to the first quarter of 2012 primarily due to higher debt principal balances outstanding during the first quarter of 2013 partially offset by slightly lower interest rates. Our average debt principal balance during the first quarter of 2013 was $16.81 billion compared to $14.50 billion during the first quarter of 2012. On a weighted-average basis, the interest rates we paid on our consolidated debt during the first quarter of 2013 were approximately 5.4% compared to 5.9% we paid during the first quarter of 2012. Lastly, interest costs capitalized in connection with our capital spending program increased $1.0 million quarter-to-quarter.

Other income for the first quarter of 2012 reflects $53.3 million of aggregate gains we recorded in connection with our sale of 26,331,868 common units of 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.

We recognized a net income tax expense of $6.4 million for the first quarter of 2013 compared to a net income tax benefit of $34.4 million for the first quarter of 2012. The $40.8 million quarter-to-quarter change in income taxes is primarily due to a $46.5 million benefit related to the conversion of certain of our subsidiaries to limited liability companies during the first quarter of 2012.

Business Segment Highlights

Total segment gross operating margin was $1.23 billion for the first quarter of 2013 compared to $1.05 billion for the first quarter of 2012.

The following information highlights significant changes in our quarter-to-quarter 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 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 March 31, 2013	For the Three Months Ended March 31, 2012
Segment gross operating margin:		
Natural gas processing and related NGL marketing activities	$ 269.6	$ 421.7
NGL pipelines and related storage	232.2	168.4
NGL fractionation	90.7	64.8
Total	$ 592.5	$ 654.9
Selected volumetric data:		
Equity NGL production (MBPD) (1)	122	112
Fee-based natural gas processing (MMcf/d) (2)	4,524	4,134
NGL transportation volumes (MBPD)	2,536	2,340
NGL fractionation volumes (MBPD)	708	623

(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 quarter-to-quarter increase in fee-based processing volumes is 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 for the first quarter of 2013 decreased $152.1 million compared to the first quarter of 2012. Gross operating margin from our natural gas processing plants located in the Rocky Mountains decreased $119.7 million quarter-to-quarter. Results from our Meeker natural gas processing plant in Colorado decreased $53.4 million quarter-to-quarter primarily due to lower natural gas processing margins during the first quarter of 2013 compared to the first quarter of 2012. In general, natural gas processing margins declined in the first quarter of 2013 compared to the first quarter of 2012 due to lower overall NGL prices, primarily ethane and propane, and higher natural gas prices quarter-to-quarter. Results from our Pioneer natural gas processing plant in Wyoming decreased $46.3 million quarter-to-quarter primarily due to a 17 MBPD decrease in equity NGL production during the first quarter of 2013 compared to the first quarter of 2012. Producers utilizing our Pioneer facility have curtailed their drilling programs in the Jonah and Pinedale production fields due to the continued low price of natural gas. In addition, our Pioneer plant is experiencing varying levels of ethane rejection, which also results in lower equity NGL production for the facility. Also, gross operating margin for the first quarter of 2012 from our Rocky Mountain plants included a $20.0 million gain related to proceeds received in a vendor settlement.

Gross operating margin from our Chaco natural gas processing plant for the first quarter of 2013 decreased $21.8 million compared to the first quarter of 2012. Results for this facility for the first quarter of 2012 included a $13.7 million benefit attributable to changes in a provision for certain plant capacity obligations. The remaining $8.1 million quarter-to-quarter decrease in gross operating margin is primarily due to lower NGL prices during the first quarter of 2013 and their impact on Chaco's percent-of-liquids processing arrangements.

Our South Texas natural gas processing plants posted a $5.9 million quarter-to-quarter increase in gross operating margin primarily due to higher equity NGL and fee-based processing volumes from the start-up of our Yoakum plant, which commenced operations in May 2012. Gross operating margins from our Louisiana and East Texas natural gas processing plants decreased a combined $10.0 million quarter-to-quarter primarily due to lower NGL prices during the first quarter of 2013 and their impact on our percent-of-liquids processing arrangements at these facilities. Lastly, gross operating margin from our NGL marketing activities decreased $4.4 million quarter-to-quarter primarily due to lower NGL sales margins.

NGL pipelines and related storage

Gross operating margin from our NGL pipelines and related storage assets for the first quarter of 2013 increased $63.8 million when compared to the first quarter of 2012. Gross operating margin from our South Texas NGL Pipeline System increased $22.0 million quarter-to-quarter primarily due to higher NGL volumes associated with Eagle Ford Shale production. This system includes our Eagle Ford NGL Pipeline, which was placed into service in April 2012 and transported 135 MBPD of NGLs during the first quarter of 2013.

Gross operating margin from our Dixie Pipeline and related NGL terminals increased $11.8 million quarter-to-quarter primarily due to higher transportation volumes, which accounted for $6.8 million of the increase, and lower pipeline integrity and maintenance expenses, which accounted for $3.3 million of the increase. Transportation volumes on the Dixie Pipeline were negatively impacted during the first quarter of 2012 due to downtime associated with various 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 combined $5.0 million quarter-to-quarter. A $16.3 million increase in revenues associated with higher system-wide tariffs and other fees, combined with a $10.3 million decrease in operating costs primarily due to pipeline gains during the first quarter of 2013, was partially offset by a $21.6 million decrease in gross operating margin attributable to lower transport volumes. Volumes on our Mid-America and Seminole pipelines decreased quarter-to-quarter primarily due to lower NGL production from Rocky Mountain gas plants caused by ethane rejection and decreased transportation volumes from the Conway hub to Mont Belvieu attributable to NGL pricing differentials.

Gross operating margin from our Houston Ship Channel LPG export terminal and related pipeline system increased $3.8 million quarter-to-quarter. Volumes at our Houston Ship Channel LPG export terminal increased 39 MBPD quarter-to-quarter and benefited from an expansion project completed during the first quarter of 2013.

Gross operating margin from our Lou-Tex NGL and Panola Pipelines increased $6.1 million quarter-to-quarter primarily due to an increase in NGL transportation volumes. Also, gross operating margin from our Mont Belvieu and other storage and terminal assets increased a combined $10.1 million quarter-to-quarter primarily due to higher volumes. As with our other Mont Belvieu assets, our Mont Belvieu storage complex continues to benefit from increased NGL production volumes from the Eagle Ford Shale.

NGL fractionation

Gross operating margin from NGL fractionation for the first quarter of 2013 increased $25.9 million when compared to the first quarter of 2012 primarily due to higher fractionation volumes at our Mont Belvieu complex. Our Mont Belvieu fractionators continue to benefit from increased NGL production volumes from the Eagle Ford Shale.

We placed into service the sixth NGL fractionation unit at our Mont Belvieu complex during the fourth quarter of 2012. Completion of this additional fractionator increased total NGL fractionation capacity at our Mont Belvieu complex by about 85 MBPD to a total of approximately 485 MBPD (433 MBPD net to our ownership interests) at the end of 2012.

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 March 31,	
	2013	**2012**
Segment gross operating margin	$ 190.8	$ 206.2
Selected volumetric data:		
Natural gas transportation volumes (BBtus/d)	13,071	13,081

Gross operating margin from onshore natural gas pipelines and services for the first quarter of 2013 decreased $15.4 million when compared to the first quarter of 2012. Gross operating margin from our San Juan, Jonah and Haynesville Gathering Systems decreased a combined $16.9 million quarter-to-quarter primarily due to lower gathering volumes. Producers served by these gathering systems have curtailed their drilling programs in response to the continued low price of natural gas and NGLs. Results from our Acadian Gas System decreased $2.0 million quarter-to-quarter primarily due to slightly higher operating costs. Lastly, gross operating margin from our natural gas marketing activities decreased $2.1 million quarter-to-quarter primarily due to lower sales margins.

Gross operating margin from our Texas Intrastate System increased $8.0 million quarter-to-quarter primarily due to higher firm capacity reservation revenues. Increased natural gas production volumes from the Eagle Ford Shale supply basin, in large part a by-product of increased NGL and crude oil production, continues to support strong demand for our natural gas transportation services on the Texas Intrastate System.

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 March 31,	
	2013	**2012**
Segment gross operating margin	$ 236.4	$ 39.3
Selected volumetric data:		
Crude oil transportation volumes (MBPD)	981	706

Gross operating margin from our onshore crude oil pipelines and services business for the first quarter of 2013 increased $197.1 million when compared to the first quarter of 2012. Gross operating margin from our crude oil marketing and related activities increased $112.3 million quarter-to-quarter primarily due to higher sales margins. Our crude oil marketing activities continue to benefit from increased crude oil production volumes from the Eagle Ford Shale, Permian Basin and Rocky Mountains regions. Gross operating margin from our South Texas Crude Oil Pipeline System increased $45.9 million quarter-to-quarter primarily due to higher transportation volumes attributable to the Eagle Ford Expansion pipeline, which commenced operations in June 2012 and transported 150 MBPD of crude oil during the first quarter of 2013. Equity earnings from our investment in crude oil pipeline joint ventures increased $36.4 million quarter-to-quarter primarily due to the completion of expansion capital projects since the first quarter of 2012.

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 March 31,	
	2013	**2012**
Segment gross operating margin	$ 40.5	$ 52.1
Selected volumetric data: (1)		
Natural gas transportation volumes (BBtus/d)	733	962
Crude oil transportation volumes (MBPD)	294	288
Platform natural gas processing (MMcf/d)	244	356
Platform crude oil processing (MBPD)	15	21

Gross operating margin from our offshore pipelines and services business for the first quarter of 2013 decreased $11.6 million when compared to the first quarter of 2012. Collectively, gross operating margin from our Independence Hub platform and Independence Trail pipeline decreased $14.1 million quarter-to-quarter primarily due to the expiration of platform demand fee revenues in March 2012, which accounted for $9.7 million of the quarter-to-quarter decrease, and lower throughput volumes during the first quarter of 2013 compared to the first quarter of 2012, which accounted for $4.4 million of the quarter-to-quarter decrease.

Lastly, gross operating margin for this segment benefited from a $3.8 million quarter-to-quarter decrease in insurance costs. Due to the high cost of windstorm coverage for our offshore Gulf of Mexico assets, we elected to self-insure our assets at a significant savings in premiums for the current annual policy period that ends in June 2013.

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 March 31,	
	2013	**2012**
Segment gross operating margin:		
Propylene fractionation and related activities	$ 35.0	$ 61.1
Butane isomerization	23.4	20.6
Octane enhancement and related plant operations	38.3	(13.1)
Refined products pipelines and related activities	56.6	12.1
Marine transportation and other	17.6	17.1
Total	$ 170.9	$ 97.8
Selected volumetric data:		
Propylene fractionation volumes (MBPD)	69	72
Butane isomerization volumes (MBPD)	85	82
Octane additive and related plant production volumes (MBPD)	16	4
Transportation volumes, primarily refined products and petrochemicals (MBPD)	681	692

Propylene fractionation and related activities

Gross operating margin from propylene fractionation and related petrochemical marketing activities for the first quarter of 2013 decreased $26.1 million when compared to the first quarter of 2012. The quarter-to-quarter decrease in gross operating margin is primarily due to lower propylene sales margins in the first quarter of 2013.

Butane isomerization

Gross operating margin from butane isomerization for the first quarter of 2013 increased $2.8 million when compared to the first quarter of 2012. Processing revenues increased a total of $2.3 million quarter-to-quarter due to higher volumes, which accounted for $1.2 million of the increase, and fees, which accounted for $1.1 million of the increase. Isomerization production volumes for the first quarter of 2013 increased 3 MBPD when compared to the first quarter of 2012. Isomerization production volumes for the first quarter of 2012 were negatively impacted by downtime for maintenance at our octane enhancement facility (which utilizes high purity isobutane produced at our butane isomerization facility as a feedstock).

Octane enhancement and related plant operations

Gross operating margin from octane enhancement and related high purity isobutylene plant operations for the first quarter of 2013 increased a combined $51.4 million when compared to the first quarter of 2012. Gross operating margin from our octane enhancement facility for the first quarter of 2013 increased $49.6 million compared to the first quarter of 2012 primarily due to higher sales volumes, which accounted for $32.6 million of the increase, and higher motor gasoline additive sales margins, which accounted for $16.4 million of the increase. The remainder of the quarter-to-quarter increase in gross operating margin from this facility was attributable to lower operating expenses (primarily repair and maintenance costs) in the first quarter of 2013. As noted previously, our octane enhancement facility experienced periods of downtime for maintenance during the first quarter of 2012, which negatively impacted production volumes and maintenance costs.

Refined products pipelines and related activities

Gross operating margin from refined products pipelines and related marketing activities for the first quarter of 2013 increased $44.5 million when compared to the first quarter of 2012. Gross operating margin from our TE Products Pipeline and related Centennial pipeline increased $13.8 million quarter-to-quarter primarily due to higher transportation tariffs, which accounted for $6.3 million of the increase, and lower maintenance expenses, which accounted for $6.8 million of the increase. Gross operating margin from the marketing of refined products increased $6.0 million quarter-to-quarter primarily due to higher sales margins.

Gross operating margin from our refined products terminals for the first quarter of 2013 increased $24.6 million when compared to the first quarter of 2012. Results for these terminals for the first quarter of 2013 include a $16.6 million benefit attributable to reductions in a provision for future pipeline capacity obligations. In addition, results for these terminals for the first quarter of 2012 include approximately $6.0 million of maintenance expenses associated with certain pipeline-related projects at our Port Arthur, Texas terminal. The combination of these two factors are the primary drivers of the $24.6 million quarter-to-quarter variance in gross operating margin for these terminal assets.

Liquidity and Capital Resources

At March 31, 2013, we had $4.78 billion of consolidated liquidity, which is defined as unrestricted cash on hand plus borrowing capacity available under EPO's $3.5 Billion Multi-Year Revolving Credit Facility. Unrestricted cash on hand at March 31, 2013 was $1.28 billion, which was higher than normal due to proceeds remaining from the recent issuance of Senior Notes HH and II on March 11, 2013. A portion of the proceeds from this senior notes offering was used to repay $650.0 million in principal amounts due on April 15, 2013 under EPO's Senior Notes M and U and the TEPPCO 5.90% Senior Notes. Based on current market conditions (as of the filing date of this quarterly report), 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. We have a universal shelf registration statement (the "2010 Shelf") on file with the SEC. The 2010 Shelf allows Enterprise Products Partners L.P. and EPO (on a standalone basis) to issue an unlimited amount of equity and debt securities, respectively. The 2010 Shelf will expire in July 2013, at which time we expect to file a replacement universal shelf registration statement.

Consolidated Debt

We had $17.53 billion of principal amounts outstanding under consolidated debt agreements at March 31, 2013. The following table presents contractually scheduled maturities of our consolidated debt obligations outstanding at March 31, 2013 for the next five years, and in total thereafter (dollars in millions):

		Scheduled Maturities of Debt					
	Total	**Remainder of 2013**	**2014**	**2015**	**2016**	**2017**	**After 2017**
Senior Notes	$ 16,000.0	$ 650.0	$ 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	$ 650.0	$ 1,150.0	$ 1,300.0	$ 750.0	$ 800.0	$ 12,882.7

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.

EPO utilized the 2010 Shelf to issue its Senior Notes HH and II in March 2013. We expect to refinance the remaining current maturities of our consolidated debt obligations at or prior to their maturity. 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 three months ended March 31, 2013 in connection with an underwritten equity offering and 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 Received
Common units issued in connection with underwritten offering	9,200,000	$ 486.6
Common units issued in connection with the DRIP and EUPP	1,275,229	67.5
Total	10,475,229	$ 554.1

Using the 2010 Shelf, we issued 9,200,000 common units (including an over-allotment of 1,200,000 common units) in February 2013 to the public at an offering price of $54.56 per unit. This equity 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.

In January 2013, affiliates of privately held EPCO, which own our general partner and approximately 37.1% of our limited partner interests at March 31, 2013, expressed their willingness to purchase at least $100 million of our common units during 2013 principally through our DRIP. In February 2013, the EPCO affiliates reinvested $25.0 million resulting in the issuance of 473,188 common units under our DRIP (this amount is a component of the 1,275,229 common units issued in total under the DRIP and EUPP). In May 2013, the EPCO affiliates reinvested an additional $25.0 million under the DRIP.

We have a registration statement on file with the SEC covering the issuance of up to $1.0 billion of our common units in amounts, at prices and on terms to be determined by market conditions and other factors at the time of such offerings. Pursuant to this "at-the-market" program, we may sell common units under an equity distribution agreement between Enterprise Products Partners L.P. and certain broker-dealers from time-to-time by means of ordinary brokers' transactions through the NYSE at market prices, in block transactions or as otherwise agreed to with the broker-dealer parties to the agreement. During the three months ended March 31, 2013, we did not issue any common units under this program. After taking into account the aggregate sales price of common units issued under this program through May 8, 2013, we have the capacity to issue additional common units under this program up to an aggregate sales price of $743.6 million.

For additional information regarding our registration statements, see Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Credit Ratings

As of May 8, 2013, the investment-grade credit ratings of EPO's long-term senior unsecured debt securities were BBB+ from Standard and Poor's and Baa1 from Moody's. Likewise, 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 Three Months Ended March 31,	
	2013	2012
Net cash flows provided by operating activities	$ 999.9	$ 604.9
Cash used in investing activities	847.2	35.5
Cash provided by (used in) financing activities	1,111.5	(500.9)

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 certain petrochemicals. The products that we process, sell, transport or store are principally used as fuel for residential, agricultural and commercial heating; as feedstocks in petrochemical manufacturing; by crude oil refineries; and in the production of motor gasoline. Reduced demand for our services or products by industrial customers, whether because of a decline in general economic conditions, reduced demand for the end products made with our products, or increased competition from other service providers or producers due to pricing differences or other reasons, could have a negative impact on our earnings and operating cash flows. For a more complete discussion of these and other risk factors pertinent to our business, see "Risk Factors" under Part I, Item 1A of our 2012 Form 10-K.

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

Comparison of Three Months Ended March 31, 2013 with Three Months Ended March 31, 2012

Operating Activities. Cash provided by operating activities for the first quarter of 2013 increased $395.0 million compared to the first quarter of 2012. The increase in cash flow was primarily due to (i) a $177.0 million quarter-to-quarter increase in cash attributable to overall higher partnership income (after adjusting our $99.8 million quarter-to-quarter increase in net income for changes in the non-cash items identified on our Unaudited Condensed Statements of Consolidated Cash Flows) and (ii) a $193.1 million quarter-to-quarter 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 $24.3 million quarter-to-quarter primarily due to improved results from our investments in crude oil pipeline joint ventures. For information regarding significant quarter-to-quarter changes in our consolidated net income and underlying segment results, see "Results of Operations" within this Item 2.

Investing Activities. Cash used in investing activities for the first quarter of 2013 increased $811.7 million compared to the first quarter of 2012. The quarter-to-quarter increase in cash used for investing activities was primarily due to increased cash contributions to unconsolidated affiliates to fund their capital spending programs, partially offset by lower cash payments for consolidated property, plant and equipment and proceeds from asset sales. Investments in unconsolidated affiliates increased $240.8 million quarter-to-quarter 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. Capital spending for consolidated property, plant and equipment, net of contributions in aid of construction costs, decreased $345.2 million quarter-to-quarter.

Proceeds from asset sales and insurance recoveries decreased from $998.2 million for the first quarter of 2012 to $130.5 million for the first quarter of 2013. Proceeds for the first quarter of 2012 primarily reflect the $975.9 million 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 quarter of 2013 primarily reflect $86.9 million we received from the sale of the Stratton Ridge-to-Mont Belvieu segment of the Seminole Pipeline and $29.5 million we received from the sale of chemical trucking assets.

Financing Activities. Cash provided by financing activities was $1.11 billion during the first quarter of 2013 compared to cash used in financing activities of $500.9 million during the first quarter of 2012. The $1.61 billion change in cash flows attributable to financing activities was primarily due to the following:

§ Net borrowings under our consolidated debt agreements increased $1.25 billion quarter-to-quarter. EPO issued $2.25 billion and repaid $550.0 million in principal amount of senior notes during the first quarter of 2013, compared to the issuance of $750.0 million and repayment of $500.0 million in principal amount of senior notes during the first quarter of 2012. In addition, net repayments under EPO's $3.5 Billion Multi-Year Revolving Credit Facility and commercial paper program increased $197.0 million quarter-to-quarter. For additional information regarding our consolidated debt obligations, see Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

§ Cash payments related to the monetization of interest rate derivative instruments increased $91.2 million quarter-to-quarter. For information regarding our interest rate hedging activities, see Note 4 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

§ Cash distributions paid to limited partners increased $47.2 million quarter-to-quarter primarily due to an increase in the number of distribution-bearing common units outstanding and the quarterly distribution rate per unit.

§ Net cash proceeds from the issuance of common units increased $521.3 million quarter-to-quarter. In total, we issued an aggregate 10,475,229 common units during the first quarter of 2013 in connection with an underwritten offering and our DRIP and EUPP. These issuances generated $554.1 million of net cash proceeds for the first quarter of 2013. This compares to 691,936 common units we issued during the first quarter of 2012 in connection with our DRIP and EUPP. These issuances generated $32.8 million of net cash proceeds for the first quarter of 2012. For additional information regarding our consolidated partners equity amounts, see Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Capital Spending

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 producing regions.

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 Three Months Ended March 31,	
	2013	2012
Capital spending for property, plant and equipment, net of contributions in aid of construction costs	$ 622.9	$ 968.1
Investments in unconsolidated affiliates	291.4	50.6
Total capital spending	$ 914.3	$ 1,018.7

Our payments for growth capital spending totaled $858.2 million for the three months ended March 31, 2013. Our most significant growth capital expenditures for the first quarter of 2013 involved projects in the Eagle Ford Shale, at Mont Belvieu, crude oil pipeline projects and the ATEX Express pipeline.

Based on information currently available, we estimate our consolidated capital spending for 2013 will approximate $4.6 billion, which includes estimated expenditures of $4.2 billion for growth capital projects and $350 million for sustaining capital expenditures. Our forecast of consolidated capital 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 debt and equity securities, and potential divestitures. We may revise our forecast of capital spending due to factors beyond our control, such as weather related issues, changes in supplier prices or adverse economic conditions. Furthermore, our forecast of capital spending may change as a result of decisions made by management at a later date, which may include the addition of costs 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 March 31, 2013, we had approximately $1.42 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.

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 presented (dollars in millions):

	For the Three Months Ended March 31,	
	2013	2012
Expensed	$ 10.7	$ 19.7
Capitalized	12.8	12.9
Total	$ 23.5	$ 32.6

We expect the cost of our pipeline integrity program, irrespective of whether such costs are capitalized or expensed, to approximate $112.0 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 in the preparation of our Unaudited Condensed Consolidated Financial Statements, such estimates are based on our current knowledge and understanding of the underlying facts and circumstances and may be revised as a result of actions we take in the future. Changes in these estimates will occur as a result of the passage of time and the occurrence of future events. Subsequent changes in these estimates may have a significant impact on our consolidated financial position, results of operations and cash flows.

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 is as follows for the periods presented (dollars in millions):

	For the Three Months Ended March 31,	
	2013	2012
NGL Pipelines & Services	$ 592.5	$ 654.9
Onshore Natural Gas Pipelines & Services	190.8	206.2
Onshore Crude Oil Pipelines & Services	236.4	39.3
Offshore Pipeline & Services	40.5	52.1
Petrochemical & Refined Products Services	170.9	97.8
Other Investments (1)	--	2.4
Total segment gross operating margin	$ 1,231.1	$ 1,052.7

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

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

	For the Three Months Ended March 31,	
	2013	2012
Total segment gross operating margin	$ 1,231.1	$ 1,052.7
Adjustments to reconcile total segment gross operating margin to operating income:		
Amounts included in operating costs and expenses:		
Depreciation, amortization and accretion	(276.8)	(254.6)
Non-cash asset impairment charges	(11.0)	(5.4)
Gains attributable to asset sales and insurance recoveries	63.9	2.5
General and administrative costs	(49.5)	(46.3)
Operating income	957.7	748.9
Other expense, net	(196.0)	(127.8)
Income before income taxes	$ 761.7	$ 621.1

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 balance of our revolving credit facility and commercial paper notes, the issuance of senior notes 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.

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.

As presented in 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 March 31, 2013 (dollars in millions):

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

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

		Interest Rate Swap Portfolio Aggregate Fair Value at		
Scenario	Resulting Classification	December 31, 2012	March 31, 2013	April 16, 2013
FV assuming no change in underlying interest rates	*Asset*	$ 28.0	$ 23.7	$ 27.2
FV assuming 10% increase in underlying interest rates	*Asset*	27.2	22.9	26.4
FV assuming 10% decrease in underlying interest rates	*Asset*	28.8	24.5	27.9

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 and having 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 March 31, 2013.

Commodity Hedging Activities

The prices of natural gas, NGLs, crude oil, refined products and certain petrochemical products are subject to fluctuations in response to changes in supply and demand, market conditions and a variety of additional factors that are beyond our control. In order to manage such price risks, we enter into commodity derivative instruments such as physical forward contracts, futures contracts, fixed-for-float swaps, basis swaps and option contracts. The following table summarizes our portfolio of commodity derivative instruments outstanding at March 31, 2013 (volume measures as noted):

	Volume (1)		**Accounting**
Derivative Purpose	**Current** (2)	**Long-Term** (2)	**Treatment**
Derivatives designated as hedging instruments:			
Octane enhancement:			
Forecasted purchases of NGLs (MMBbls)	1.5	n/a	Cash flow hedge
Forecasted sales of octane enhancement products (MMBbls)	3.2	n/a	Cash flow hedge
Natural gas marketing:			
Forecasted sales of natural gas (Bcf)	0.1	n/a	Cash flow hedge
Natural gas storage inventory management activities (Bcf)	1.9	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	3.4	n/a	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	6.5	n/a	Cash flow hedge
Refined products marketing:			
Refined products inventory management activities (MMBbls)	0.1	n/a	Fair value hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	3.9	n/a	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	8.8	n/a	Cash flow hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (Bcf) (3,4)	162.7	25.9	Mark-to-market
Refined products risk management activities (MMBbls) (4)	0.5	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (4)	3.7	n/a	Mark-to-market

(1) Volume for derivatives designated as hedging instruments reflects the total amount of volumes hedged whereas volume for derivatives not designated as hedging instruments reflects the absolute value of derivative notional volumes.
(2) The maximum term for derivatives designated as cash flow hedges, derivatives designated as fair value hedges and derivatives not designated as hedging instruments is March 2014, March 2014 and October 2015, respectively.
(3) Current volumes include 89.5 Bcf of physical derivative instruments that are predominantly priced at a market-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 May 1, 2013, our predominant commodity hedging strategies consisted of (i) hedging anticipated future contracted sales of NGLs, crude oil, and related products associated with volumes held in inventory and (ii) hedging the fair value of natural gas and refined products in inventory. The following information summarizes these hedging strategies:

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

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

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

Certain basis swaps, basis spread options and other derivative instruments not designated as hedging instruments are used to manage market risks associated with anticipated purchases and sales of natural gas necessary to optimize our owned and contractually committed transportation and storage capacity. There is some uncertainty involved in the timing of these transactions often due to the development of more favorable profit opportunities or when spreads are insufficient to cover variable costs thus reducing the likelihood that the transactions will occur as originally forecasted. As a result of this timing uncertainty, these derivative instruments do not qualify for hedge accounting even though they are effective at managing the risk exposures of these assets. The earnings volatility caused by fluctuations in non-cash, mark-to-market earnings cannot be predicted and the impact to earnings could be material.

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**	**March 31, 2013**	**April 16, 2013**
FV assuming no change in underlying commodity prices	*Asset (Liability)*	$ 7.6	$ (0.7)	$ (2.3)
FV assuming 10% increase in underlying commodity prices	*Asset (Liability)*	3.0	(5.2)	(7.3)
FV assuming 10% decrease in underlying commodity prices	*Asset*	12.2	3.9	2.8

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

		Portfolio Fair Value at		
Scenario	**Resulting Classification**	**December 31, 2012**	**March 31, 2013**	**April 16, 2013**
FV assuming no change in underlying commodity prices	*Asset (Liability)*	$ 10.5	$ (30.6)	$ (2.1)
FV assuming 10% increase in underlying commodity prices	*Liability*	(27.5)	(67.7)	(33.9)
FV assuming 10% decrease in underlying commodity prices	*Asset*	48.5	6.4	29.8

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**	**March 31, 2013**	**April 16, 2013**
FV assuming no change in underlying commodity prices	*Asset (Liability)*	$ (2.0)	$ (3.7)	$ 21.1
FV assuming 10% increase in underlying commodity prices	*Liability*	(10.0)	(17.6)	--
FV assuming 10% decrease in underlying commodity prices	*Asset*	6.1	10.2	42.2

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 first quarter of 2013, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

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

PART II. OTHER INFORMATION

Item 1. *Legal Proceedings*.

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

Item 1A. *Risk Factors*.

Security holders and potential investors in our securities should carefully consider the risk factors set forth in our 2012 Form 10-K, in addition to other information in such 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 three months ended March 31, 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	--	--

(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.

Item 3. *Defaults Upon Senior Securities.*

None.

Item 4. *Mine Safety Disclosures*.

Not applicable.

Item 5. ***Other Information.***

None.

Item 6. ***Exhibits.***

Exhibit Number	Exhibit*
2.1	Merger Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed December 15, 2003).
2.2	Amendment No. 1 to Merger Agreement, dated as of August 31, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed September 7, 2004).
2.3	Parent Company Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.2 to Form 8-K filed December 15, 2003).
2.4	Amendment No. 1 to Parent Company Agreement, dated as of April 19, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.1 to Form 8-K filed April 21, 2004).
2.5	Purchase and Sale Agreement (Gas Plants), dated as of December 15, 2003, by and between El Paso Corporation, El Paso Field Services Management, Inc., El Paso Transmission, L.L.C., El Paso Field Services Holding Company and Enterprise Products Operating L.P. (incorporated by reference to Exhibit 2.4 to Form 8-K filed December 15, 2003).
2.6	Agreement and Plan of Merger, dated as of June 28, 2009, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Sub B LLC, TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed June 29, 2009).
2.7	Agreement and Plan of Merger, dated as of June 28, 2009, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Sub A LLC, TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (incorporated by reference to Exhibit 2.2 to Form 8-K filed June 29, 2009).
2.8	Agreement and Plan of Merger, dated as of September 3, 2010, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise ETE LLC, Enterprise GP Holdings L.P. and EPE Holdings, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed September 7, 2010).
2.9	Agreement and Plan of Merger, dated as of September 3, 2010, by and among Enterprise Products GP, LLC, Enterprise GP Holdings L.P. and EPE Holdings, LLC (incorporated by reference to Exhibit 2.2 to Form 8-K filed September 7, 2010).
2.10	Contribution Agreement, dated as of September 30, 2010, by and between Enterprise Products Company and Enterprise Products Partners L.P. (incorporated by reference to Exhibit 2.1 to Form 8-K filed October 1, 2010).
2.11	Agreement and Plan of Merger, dated as of April 28, 2011, by and among Enterprise Products Partners L.P., Enterprise Products Holdings LLC, EPD MergerCo LLC, Duncan Energy Partners L.P. and DEP Holdings, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed April 29, 2011).
3.1	Certificate of Limited Partnership of Enterprise Products Partners L.P. (incorporated by reference to Exhibit 3.6 to Form 10-Q filed November 9, 2007).

3.2	Certificate of Amendment to Certificate of Limited Partnership of Enterprise Products Partners L.P., filed on November 22, 2010 with the Delaware Secretary of State (incorporated by reference to Exhibit 3.6 to Form 8-K filed November 23, 2010).
3.3	Sixth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated November 22, 2010 (incorporated by reference to Exhibit 3.2 to Form 8-K filed November 23, 2010).
3.4	Amendment No. 1 to Sixth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated effective as of August 11, 2011 (incorporated by reference to Exhibit 3.1 to Form 8-K filed August 16, 2011).
3.5	Certificate of Formation of Enterprise Products Holdings LLC (formerly named EPE Holdings, LLC) (incorporated by reference to Exhibit 3.3 to Form S-1/A Registration Statement, Reg. No. 333-124320, filed by Enterprise GP Holdings L.P. on July 22, 2005).
3.6	Certificate of Amendment to Certificate of Formation of Enterprise Products Holdings LLC (formerly named EPE Holdings, LLC), filed on November 22, 2010 with the Delaware Secretary of State (incorporated by reference to Exhibit 3.5 to Form 8-K filed November 23, 2010).
3.7	Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products Holdings LLC dated effective as of September 7, 2011 (incorporated by reference to Exhibit 3.1 to Form 8-K filed September 8, 2011).
3.8	Company Agreement of Enterprise Products Operating LLC dated June 30, 2007 (incorporated by reference to Exhibit 3.3 to Form 10-Q filed August 8, 2007).
3.9	Certificate of Incorporation of Enterprise Products OLPGP, Inc., dated December 3, 2003 (incorporated by reference to Exhibit 3.5 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
3.10	Bylaws of Enterprise Products OLPGP, Inc., dated December 8, 2003 (incorporated by reference to Exhibit 3.6 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
4.1	Form of Common Unit certificate (incorporated by reference to Exhibit A to Exhibit 3.1 to Form 8-K filed August 16, 2011).
4.2	Indenture, dated as of March 15, 2000, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed March 10, 2000).
4.3	First Supplemental Indenture, dated as of January 22, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.4	Second Supplemental Indenture, dated as of February 14, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 10-K filed March 31, 2003).
4.5	Third Supplemental Indenture, dated as of June 30, 2007, among Enterprise Products Operating L.P., as Original Issuer, Enterprise Products Partners L.P., as Parent Guarantor, Enterprise Products Operating LLC, as New Issuer, and U.S. Bank National Association, as successor Trustee (incorporated by reference to Exhibit 4.55 to Form 10-Q filed August 8, 2007).
4.6	Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed October 6, 2004).
4.7	Third Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed October 6, 2004).
4.8	Fourth Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 6, 2004).

4.9	Fifth Supplemental Indenture, dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed March 3, 2005).
4.10	Sixth Supplemental Indenture, dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed March 3, 2005).
4.11	Eighth Supplemental Indenture, dated as of July 18, 2006, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006).
4.12	Ninth Supplemental Indenture, dated as of May 24, 2007, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed May 24, 2007).
4.13	Tenth Supplemental Indenture, dated as of June 30, 2007, among Enterprise Products Operating L.P., as Original Issuer, Enterprise Products Partners L.P., as Parent Guarantor, Enterprise Products Operating LLC, as New Issuer, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.54 to Form 10-Q filed August 8, 2007).
4.14	Eleventh Supplemental Indenture, dated as of September 4, 2007, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed September 5, 2007).
4.15	Twelfth Supplemental Indenture, dated as of April 3, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed April 3, 2008).
4.16	Thirteenth Supplemental Indenture, dated as of April 3, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed April 3, 2008).
4.17	Fourteenth Supplemental Indenture, dated as of December 8, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed December 8, 2008).
4.18	Fifteenth Supplemental Indenture, dated as of June 10, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed June 10, 2009).
4.19	Sixteenth Supplemental Indenture, dated as of October 5, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.20	Seventeenth Supplemental Indenture, dated as of October 27, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed October 28, 2009).
4.21	Eighteenth Supplemental Indenture, dated as of October 27, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed October 28, 2009).
4.22	Nineteenth Supplemental Indenture, dated as of May 20, 2010, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed May 20, 2010).

4.23	Twentieth Supplemental Indenture, dated as of January 13, 2011, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed January 13, 2011).
4.24	Twenty-First Supplemental Indenture, dated as of August 24, 2011, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed August 24, 2011).
4.25	Twenty-Second Supplemental Indenture, dated as of February 15, 2012, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.25 to Form 10-Q filed May 10, 2012).
4.26	Twenty-Third Supplemental Indenture, dated as of August 13, 2012, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed August 13, 2012).
4.27	Twenty-Fourth Supplemental Indenture, dated as of March 18, 2013, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed March 18, 2013).
4.28	Form of Global Note representing $350.0 million principal amount of 6.375% Series B Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.29	Form of Global Note representing $499.2 million principal amount of 6.875% Series B Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.8 to Form 10-K filed March 31, 2003).
4.30	Form of Global Note representing $500.0 million principal amount of 5.60% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.17 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005).
4.31	Form of Global Note representing $150.0 million principal amount of 5.60% Series B Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.18 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005).
4.32	Form of Global Note representing $350.0 million principal amount of 6.65% Series B Senior Notes due 2034 with attached Guarantee (incorporated by reference to Exhibit 4.19 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005).
4.33	Form of Global Note representing $250.0 million principal amount of 5.00% Series B Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.31 to Form 10-Q filed November 4, 2005).
4.34	Form of Global Note representing $250.0 million principal amount of 5.75% Series B Senior Notes due 2035 with attached Guarantee (incorporated by reference to Exhibit 4.32 to Form 10-Q filed November 4, 2005).
4.35	Form of Junior Subordinated Note, including Guarantee (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006).
4.36	Form of Global Note representing $800.0 million principal amount of 6.30% Senior Notes due 2017 with attached Guarantee (incorporated by reference to Exhibit 4.38 to Form 10-Q filed November 9, 2007).
4.37	Form of Global Note representing $400.0 million principal amount of 5.65% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed April 3, 2008).
4.38	Form of Global Note representing $700.0 million principal amount of 6.50% Senior Notes due 2019 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed April 3, 2008).
4.39	Form of Global Note representing $500.0 million principal amount of 9.75% Senior Notes due 2014 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed December 8, 2008).
4.40	Form of Global Note representing $500.0 million principal amount of 4.60% Senior Notes due 2012 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed June 10, 2009).

4.41	Form of Global Note representing $500.0 million principal amount of 5.25% Senior Notes due 2020 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.42	Form of Global Note representing $600.0 million principal amount of 6.125% Senior Notes due 2039 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.43	Form of Global Note representing $490.5 million principal amount of 7.625% Senior Notes due 2012 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 28, 2009).
4.44	Form of Global Note representing $182.6 million principal amount of 6.125% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed October 28, 2009).
4.45	Form of Global Note representing $237.6 million principal amount of 5.90% Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 28, 2009).
4.46	Form of Global Note representing $349.7 million principal amount of 6.65% Senior Notes due 2018 with attached Guarantee (incorporated by reference to Exhibit 4.6 to Form 8-K filed October 28, 2009).
4.47	Form of Global Note representing $399.6 million principal amount of 7.55% Senior Notes due 2038 with attached Guarantee (incorporated by reference to Exhibit 4.7 to Form 8-K filed October 28, 2009).
4.48	Form of Global Note representing $285.8 million principal amount of 7.000% Junior Subordinated Notes due 2067 with attached Guarantee (incorporated by reference to Exhibit 4.8 to Form 8-K filed October 28, 2009).
4.49	Form of Global Note representing $400.0 million principal amount of 3.70% Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed May 20, 2010).
4.50	Form of Global Note representing $1.0 billion principal amount of 5.20% Senior Notes due 2020 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed May 20, 2010).
4.51	Form of Global Note representing $600.0 million principal amount of 6.45% Senior Notes due 2040 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed May 20, 2010).
4.52	Form of Global Note representing $750.0 million principal amount of 3.20% Senior Notes due 2016 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed January 13, 2011).
4.53	Form of Global Note representing $750.0 million principal amount of 5.95% Senior Notes due 2041 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed January 13, 2011).
4.54	Form of Global Note representing $650.0 million principal amount of 4.05% Senior Notes due 2022 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed August 24, 2011).
4.55	Form of Global Note representing $600.0 million principal amount of 5.70% Senior Notes due 2042 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed August 24, 2011).
4.56	Form of Global Note representing $750.0 million principal amount of 4.85% Senior Notes due 2042 with attached Guarantee (included in Exhibit 4.25 above).
4.57	Form of Global Note representing $650.0 million principal amount of 1.25% Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed August 13, 2012).
4.58	Form of Global Note representing $1.1 billion principal amount of 4.45% Senior Notes due 2043 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed August 13, 2012).

4.59	Form of Global Note representing $1.25 billion principal amount of 3.35% Senior Notes due 2023 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed March 18, 2013).
4.60	Form of Global Note representing $1.0 billion principal amount of 4.85% Senior Notes due 2044 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed March 18, 2013).
4.61	Replacement Capital Covenant, dated May 24, 2007, executed by Enterprise Products Operating L.P. and Enterprise Products Partners L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 99.1 to Form 8-K filed May 24, 2007).
4.62	First Amendment to Replacement Capital Covenant dated August 25, 2006, executed by Enterprise Products Operating L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 99.2 to Form 8-K filed August 25, 2006).
4.63	Replacement Capital Covenant, dated October 27, 2009, among Enterprise Products Operating LLC and Enterprise Products Partners L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 4.9 to Form 8-K filed October 28, 2009).
4.64	Indenture, dated February 20, 2002, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as Subsidiary Guarantors, and First Union National Bank, NA, as Trustee (incorporated by reference to Exhibit 99.2 to the Form 8-K filed by TEPPCO Partners, L.P. on February 20, 2002).
4.65	First Supplemental Indenture, dated February 20, 2002, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as Subsidiary Guarantors, and First Union National Bank, NA, as Trustee (incorporated by reference to Exhibit 99.3 to the Form 8-K filed by TEPPCO Partners, L.P. on February 20, 2002).
4.66	Second Supplemental Indenture, dated June 27, 2002, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as Initial Subsidiary Guarantors, Val Verde Gas Gathering Company, L.P., as New Subsidiary Guarantor, and Wachovia Bank, National Association, formerly known as First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.6 to the Form 10-Q filed by TEPPCO Partners, L.P. on August 14, 2002).
4.67	Third Supplemental Indenture, dated January 20, 2003, by and among TEPPCO Partners, L.P. as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Jonah Gas Gathering Company and Val Verde Gas Gathering Company, L.P. as Subsidiary Guarantors, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.7 to the Form 10-K filed by TEPPCO Partners, L.P. on March 21, 2003).
4.68	Full Release of Guarantee, dated July 31, 2006, by Wachovia Bank, National Association, as Trustee, in favor of Jonah Gas Gathering Company (incorporated by reference to Exhibit 4.8 to the Form 10-Q filed by TEPPCO Partners, L.P. on November 7, 2006).
4.69	Fourth Supplemental Indenture, dated June 30, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Val Verde Gas Gathering Company, L.P., TE Products Pipeline Company, LLC and TEPPCO Midstream Companies, LLC, as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.3 to the Form 8-K filed by TE Products Pipeline Company, LLC on July 6, 2007).
4.70	Fifth Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.11 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008).
4.71	Sixth Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.12 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008).

4.72	Seventh Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.13 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008).
4.73	Eighth Supplemental Indenture, dated October 27, 2009, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.1 to the Form 8-K filed by TEPPCO Partners, L.P. on October 28, 2009).
4.74	Full Release of Guarantee, dated November 23, 2009, of TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P. by U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.64 to Form 10-K filed on March 1, 2010).
4.75	Indenture, dated May 14, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 99.1 of the Form 8-K filed by TEPPCO Partners, L.P. on May 15, 2007).
4.76	First Supplemental Indenture, dated May 18, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TEPPCO Partners, L.P. on May 18, 2007).
4.77	Replacement of Capital Covenant, dated May 18, 2007, executed by TEPPCO Partners, L.P., TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P. in favor of the covered debt holders described therein (incorporated by reference to Exhibit 99.1 to the Form 8-K of TEPPCO Partners, L.P. on May 18, 2007).
4.78	Second Supplemental Indenture, dated as of June 30, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Existing Subsidiary Guarantors, TE Products Pipeline Company, LLC and TEPPCO Midstream Companies, LLC, as New Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TE Products Pipeline Company, LLC on July 6, 2007).
4.79	Third Supplemental Indenture, dated as of October 27, 2009, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TEPPCO Partners, L.P. on October 28, 2009).
4.80	Full Release of Guarantee, dated as of November 23, 2009, of TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P. by The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.70 to Form 10-K filed on March 1, 2010).
12.1#	Computation of ratio of earnings to fixed charges for the three months ended March 31, 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 three months ended March 31, 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 three months ended March 31, 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 three months ended March 31, 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 three months ended March 31, 2013.
101.CAL#	XBRL Calculation Linkbase Document

101.DEF#	XBRL Definition Linkbase Document
101.INS#	XBRL Instance Document
101.LAB#	XBRL Labels Linkbase Document
101.PRE#	XBRL Presentation Linkbase Document
101.SCH#	XBRL Schema Document

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

SIGNATURES

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

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

By: Enterprise Products Holdings LLC, as General Partner

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

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

	For the Three Months Ended March 31, 2013	For the Year Ended December 31, 2012	2011	2010	2009	2008
Consolidated income	$ 755.3	$ 2,428.0	$ 2,088.3	$ 1,383.7	$ 1,140.3	$ 1,145.1
Add: Provision for (benefit from) taxes	6.4	(17.2)	27.2	26.1	25.3	31.0
Less: Equity in earnings from unconsolidated affiliates	(44.5)	(64.3)	(46.4)	(62.0)	(92.3)	(66.2)
Consolidated pre-tax income before equity in earnings from unconsolidated affiliates	717.2	2,346.5	2,069.1	1,347.8	1,073.3	1,109.9
Add: Fixed charges	234.8	920.3	879.5	813.4	760.6	717.9
Amortization of capitalized interest	5.5	20.3	17.5	16.8	15.3	13.4
Distributed income of equity investees	51.3	116.7	156.4	191.9	169.3	157.2
Subtotal	1,008.8	3,403.8	3,122.5	2,369.9	2,018.5	1,998.4
Less: Capitalized interest	(31.6)	(116.8)	(106.7)	(47.2)	(53.1)	(90.7)
Net income attributable to noncontrolling interests	(1.8)	(8.1)	(20.5)	(25.5)	(26.4)	(23.0)
Total earnings	$ 975.4	$ 3,278.9	$ 2,995.3	$ 2,297.2	$ 1,939.0	$ 1,884.7
Fixed charges:						
Interest expense	$ 195.9	$ 771.8	$ 744.1	$ 741.9	$ 687.3	$ 608.3
Capitalized interest	31.6	116.8	106.7	47.2	53.1	90.7
Interest portion of rental expense	7.3	31.7	28.7	24.3	20.2	18.9
Total	$ 234.8	$ 920.3	$ 879.5	$ 813.4	$ 760.6	$ 717.9
Ratio of earnings to fixed charges	4.2x	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: May 8, 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: May 8, 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 March 31, 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: May 8, 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 March 31, 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: May 8, 2013