UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2015

OR

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

For the transition period from ___ to ___.

Commission file number: 1-14323

ENTERPRISE PRODUCTS PARTNERS L.P.

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**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 ☐

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

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

Yes ☐ No ☐

There were 2,003,159,484 common units of Enterprise Products Partners L.P. outstanding at the close of business on July 31, 2015. Our common units trade on the New York Stock Exchange under the ticker symbol "EPD."

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

Item 1. *Financial Statements*.

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

	June 30, 2015	December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	$ 551.1	$ 74.4
Restricted cash	46.1	--
Accounts receivable – trade, net of allowance for doubtful accounts of $13.9 at June 30, 2015 and $13.9 at December 31, 2014	3,346.1	3,823.0
Accounts receivable – related parties	2.4	2.8
Inventories	999.8	1,014.2
Assets held for sale (see Note 6)	1,710.7	--
Prepaid and other current assets	522.6	576.3
Total current assets	7,178.8	5,490.7
Property, plant and equipment, net	29,783.8	29,881.6
Investments in unconsolidated affiliates	2,607.2	3,042.0
Intangible assets, net of accumulated amortization of $1,164.0 at June 30, 2015 and $1,246.3 at December 31, 2014 (see Note 9)	2,733.5	4,302.1
Goodwill (see Note 9)	5,664.8	4,292.7
Other assets	191.3	184.4
Total assets	$ 48,159.4	$ 47,193.5
LIABILITIES AND EQUITY		
Current liabilities:		
Current maturities of debt (see Note 10)	$ 1,400.1	$ 2,206.4
Accounts payable – trade	790.3	773.8
Accounts payable – related parties	115.5	118.9
Accrued product payables	3,240.1	3,853.3
Accrued interest	350.0	335.5
Liabilities related to assets held for sale (see Note 6)	116.4	--
Other current liabilities	453.7	585.8
Total current liabilities	6,466.1	7,873.7
Long-term debt (see Note 10)	20,892.9	19,157.4
Deferred tax liabilities	55.0	66.6
Other long-term liabilities	382.2	403.6
Commitments and contingencies (see Note 15)		
Equity:		
Partners' equity:		
Limited partners:		
Common units (2,003,173,384 units outstanding at June 30, 2015 and 1,937,324,817 units outstanding at December 31, 2014)	20,404.2	18,304.8
Accumulated other comprehensive loss	(278.6)	(241.6)
Total partners' equity	20,125.6	18,063.2
Noncontrolling interests held (see Note 11)	175.4	1,629.0
Noncontrolling interests in assets held for sale (see Note 6)	62.2	--
Total noncontrolling interests	237.6	1,629.0
Total equity	20,363.2	19,692.2
Total liabilities and equity	$ 48,159.4	$ 47,193.5

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
Revenues:				
Third parties	$ 7,085.2	$ 12,503.5	$ 14,551.6	$ 25,377.9
Related parties	7.3	17.3	13.4	52.8
Total revenues (see Note 12)	7,092.5	12,520.8	14,565.0	25,430.7
Costs and expenses:				
Operating costs and expenses:				
Third parties	6,090.4	11,382.4	12,474.7	23,000.8
Related parties	267.1	256.7	499.2	518.8
Total operating costs and expenses	6,357.5	11,639.1	12,973.9	23,519.6
General and administrative costs:				
Third parties	16.8	18.9	37.1	41.9
Related parties	28.1	28.8	57.1	59.0
Total general and administrative costs	44.9	47.7	94.2	100.9
Total costs and expenses (see Note 12)	6,402.4	11,686.8	13,068.1	23,620.5
Equity in income of unconsolidated affiliates	110.2	50.3	199.4	106.8
Operating income	800.3	884.3	1,696.3	1,917.0
Other income (expense):				
Interest expense	(240.4)	(228.9)	(479.5)	(449.8)
Change in fair value of Liquidity Option Agreement (see Note 15)	(11.5)	--	(11.5)	--
Other, net	0.3	1.1	0.8	0.8
Total other expense, net	(251.6)	(227.8)	(490.2)	(449.0)
Income before income taxes	548.7	656.5	1,206.1	1,468.0
Benefit from (provision for) income taxes	7.9	(10.0)	1.1	(14.8)
Net income	556.6	646.5	1,207.2	1,453.2
Net income attributable to noncontrolling interests (see Note 11)	(5.6)	(8.8)	(20.1)	(16.7)
Net income attributable to limited partners	$ 551.0	$ 637.7	$ 1,187.1	$ 1,436.5
Earnings per unit: (see Note 14)				
Basic earnings per unit	$ 0.28	$ 0.35	$ 0.61	$ 0.79
Diluted earnings per unit	$ 0.28	$ 0.34	$ 0.60	$ 0.76

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
Net income	$ 556.6	$ 646.5	$ 1,207.2	$ 1,453.2
Other comprehensive income (loss):				
Cash flow hedges:				
Commodity derivative instruments:				
Changes in fair value of cash flow hedges	(4.3)	(32.8)	26.5	(42.0)
Reclassification of losses (gains) to net income	(20.2)	14.9	(81.3)	30.9
Interest rate derivative instruments:				
Reclassification of losses to net income	8.7	8.0	17.4	15.9
Total cash flow hedges	(15.8)	(9.9)	(37.4)	4.8
Other	0.4	--	0.4	--
Total other comprehensive income (loss)	(15.4)	(9.9)	(37.0)	4.8
Comprehensive income	541.2	636.6	1,170.2	1,458.0
Comprehensive income attributable to noncontrolling interests	(5.6)	(8.8)	(20.1)	(16.7)
Comprehensive income attributable to limited partners	$ 535.6	$ 627.8	$ 1,150.1	$ 1,441.3

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

	For the Six Months Ended June 30, 2015	2014
Operating activities:		
Net income	$ 1,207.2	$ 1,453.2
Reconciliation of net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	774.9	651.0
Non-cash asset impairment charges (see Note 4)	112.3	12.5
Equity in income of unconsolidated affiliates	(199.4)	(106.8)
Distributions received from unconsolidated affiliates	265.5	157.1
Net losses (gains) attributable to asset sales and insurance recoveries (see Note 16)	2.4	(96.4)
Deferred income tax expense (benefit)	(11.7)	0.6
Changes in fair value of Liquidity Option Agreement	11.5	--
Changes in fair market value of derivative instruments	(9.9)	(6.2)
Net effect of changes in operating accounts (see Note 16)	(250.7)	(198.6)
Other operating activities	(0.5)	5.5
Net cash flows provided by operating activities	1,901.6	1,871.9
Investing activities:		
Capital expenditures	(1,638.0)	(1,186.4)
Contributions in aid of construction costs	7.8	13.9
Decrease (increase) in restricted cash	(46.1)	8.9
Investments in unconsolidated affiliates	(114.1)	(498.8)
Proceeds from asset sales and insurance recoveries (see Note 16)	5.9	113.2
Other investing activities	(4.8)	(5.7)
Cash used in investing activities	(1,789.3)	(1,554.9)
Financing activities:		
Borrowings under debt agreements	13,838.3	4,182.8
Repayments of debt	(12,905.0)	(3,161.3)
Debt issuance costs	(18.6)	(18.1)
Cash distributions paid to limited partners (see Note 11)	(1,437.3)	(1,288.4)
Cash payments made in connection with distribution equivalent rights	(3.4)	(1.2)
Cash distributions paid to noncontrolling interests	(24.8)	(19.7)
Cash contributions from noncontrolling interests	22.0	4.0
Net cash proceeds from the issuance of common units	944.1	223.3
Other financing activities	(50.9)	(53.3)
Cash provided by (used in) financing activities	364.4	(131.9)
Net change in cash and cash equivalents	476.7	185.1
Cash and cash equivalents, January 1	74.4	56.9
Cash and cash equivalents, June 30	$ 551.1	$ 242.0

See Notes to Unaudited Condensed Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED EQUITY
(See Note 11 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, 2014	$ 18,304.8	$ (241.6)	$ 1,629.0	$ 19,692.2
Net income	1,187.1	--	20.1	1,207.2
Cash distributions paid to limited partners	(1,437.3)	--	--	(1,437.3)
Cash payments made in connection with distribution equivalent rights	(3.4)	--	--	(3.4)
Cash distributions paid to noncontrolling interests	--	--	(24.8)	(24.8)
Cash contributions from noncontrolling interests	--	--	22.0	22.0
Common units issued in connection with Step 2 of Oiltanking acquisition	1,408.7	--	(1,408.7)	--
Net cash proceeds from the issuance of common units	944.1	--	--	944.1
Amortization of fair value of equity-based awards	49.7	--	--	49.7
Cash flow hedges	--	(37.4)	--	(37.4)
Other	(49.5)	0.4	--	(49.1)
Balance, June 30, 2015	$ 20,404.2	$ (278.6)	$ 237.6	$ 20,363.2

	Partners' Equity			
	Limited Partners	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
Balance, December 31, 2013	$ 15,573.8	$ (359.0)	$ 225.6	$ 15,440.4
Net income	1,436.5	--	16.7	1,453.2
Cash distributions paid to limited partners	(1,288.4)	--	--	(1,288.4)
Cash payments made in connection with distribution equivalent rights	(1.2)	--	--	(1.2)
Cash distributions paid to noncontrolling interests	--	--	(19.7)	(19.7)
Cash contributions from noncontrolling interests	--	--	4.0	4.0
Net cash proceeds from the issuance of common units	223.3	--	--	223.3
Amortization of fair value of equity-based awards	39.9	--	--	39.9
Cash flow hedges	--	4.8	--	4.8
Other	(53.1)	--	(0.8)	(53.9)
Balance, June 30, 2014	$ 15,930.8	$ (354.2)	$ 225.8	$ 15,802.4

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 privately held Texas limited liability company.

The membership interests of Dan Duncan LLC are owned 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; and (iii) Richard H. Bachmann. 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 privately held Texas corporation, and its privately held affiliates. A majority of the outstanding voting capital stock of EPCO is owned by a voting trust, the current trustees ("EPCO Trustees") of which are: (i) Ms. Williams, who serves as Chairman of EPCO; (ii) Dr. Cunningham, who serves as a Vice Chairman of EPCO; and (iii) Mr. Bachmann, who serves as the President and Chief Executive Officer ("CEO") of EPCO. Each of the EPCO Trustees is also a director of EPCO.

In addition to owning our general partner, EPCO and its privately held affiliates owned approximately 34.4% of our limited partner interests at June 30, 2015.

References to "Oiltanking" and "Oiltanking GP" mean Oiltanking Partners, L.P. and OTLP GP, LLC, the general partner of Oiltanking, respectively. In October 2014, we acquired approximately 65.9% of the limited partner interests of Oiltanking, all of the member interests of Oiltanking GP and the incentive distribution rights ("IDRs") held by Oiltanking GP from Oiltanking Holding Americas, Inc. ("OTA") as the first step of a two-step acquisition of Oiltanking. In February 2015, we completed the second step of this acquisition. See Note 11 for additional information regarding this acquisition.

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

References to "Offshore Gulf of Mexico Business" or "Offshore Business" refer to the operations we sold to Genesis Energy, L.P. ("Genesis") in July 2015. See Note 6 for information regarding this sale.

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, petrochemicals and refined products.

Our integrated midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States ("U.S."), Canada and Gulf of Mexico with domestic consumers and international markets. Our midstream energy operations currently include: natural gas gathering, treating, processing, transportation and storage; NGL transportation, fractionation, storage, and import and export terminals (including liquefied petroleum gas or "LPG"); crude oil gathering, transportation, storage and terminals; petrochemical and refined products transportation, storage and terminals, and related 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 currently include approximately 49,000 miles of onshore pipelines; 225 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.

Our historical operations are reported under five business segments: (i) NGL Pipelines & Services, (ii) Crude Oil Pipelines & Services, (iii) Natural Gas Pipelines & Services, (iv) Petrochemical & Refined Products Services and (v) Offshore Pipelines & Services.

On July 24, 2015, we completed the sale of our Offshore Business to Genesis. The assets, liabilities and related noncontrolling interest attributable to this business were classified as held for sale at June 30, 2015 (see Note 6). As a result of this sale, we renamed our Onshore Crude Oil Pipelines & Services business segment "Crude Oil Pipelines & Services." In addition, we renamed our Onshore Natural Gas Pipelines & Services business segment "Natural Gas Pipelines & Services." The operations reported within these two onshore segments did not change due to these name changes. We will continue to report the historical results of the Offshore Pipelines & Services segment through the closing date of the sales transaction. See Note 12 for additional information regarding our business segments.

See Note 18 for information regarding our recently completed acquisition of the member interests of EFS Midstream LLC.

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. We, Enterprise GP, EPCO and Dan Duncan LLC are affiliates under the collective common control of the DD LLC Trustees and the EPCO Trustees. 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 (the "ASA") or by other service providers. See Note 13 for information regarding the ASA and other related party matters.

In August 2014, we completed a two-for-one common unit split. All per unit amounts and number of units outstanding presented in these Unaudited Condensed Consolidated Financial Statements and Notes thereto are on a post-split basis.

Note 2. General Accounting and Disclosure Matters

Our results of operations for the three and six months ended June 30, 2015 are not necessarily indicative of results expected for the full year of 2015. 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 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, 2014 (the "2014 Form 10-K") filed with the SEC on March 2, 2015.

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 15 for additional information regarding our contingencies.

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

For certain physical forward commodity derivative contracts, we apply the normal purchase/normal sale exception, whereby changes in the mark-to-market values of such contracts are not recognized in income. As a result, the revenues and expenses associated with such physical transactions are recognized during the period when volumes are physically delivered or received. Physical forward commodity contracts subject to this exception are evaluated for the probability of future delivery and are periodically back-tested once the forecasted period has passed to determine whether similar forward contracts are probable of physical delivery in the future. See Note 4 for additional information regarding our derivative instruments.

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

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

Income Taxes
Provision for or benefit from income taxes primarily reflects our state tax obligations under the Revised Texas Franchise Tax (the "Texas Margin Tax"). For the three and six months ended June 30, 2015, we recognized a net income tax benefit of $7.9 million and $1.1 million, respectively, primarily due to certain legislative changes to the Texas Margin Tax enacted during the second quarter of 2015 that reduced the tax rate for business entities that operate within the state. For the three and six months ended June 30, 2014, we recognized net income tax expense of $10.0 million and $14.8 million, respectively.

Restricted Cash
Restricted cash represents amounts held in segregated bank accounts by our clearing brokers as margin in support of our commodity derivative instruments portfolio and related physical purchases and sales of natural gas, NGLs, crude oil and refined products. Additional cash may be restricted to maintain our commodity derivative instruments portfolio as prices fluctuate or deposit requirements change. At June 30, 2015, our restricted cash amounts were $46.1 million. We did not have any restricted cash as of December 31, 2014. See Note 4 for information regarding our derivative instruments and hedging activities.

Note 3. Equity-based Awards

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
Equity-classified awards:				
Restricted common unit awards	$ 3.9	$ 9.0	$ 10.0	$ 20.6
Phantom unit awards	22.7	13.6	39.9	19.4
Liability-classified awards	0.1	0.2	0.2	0.3
Total	$ 26.7	$ 22.8	$ 50.1	$ 40.3

The fair value of equity-classified awards is amortized into earnings over the requisite service or vesting period. Equity-classified awards are expected to result in the issuance of common units upon vesting. Compensation expense for liability-classified awards is recognized over the requisite service or vesting period based on the fair value of the award remeasured at each reporting date. Liability-classified awards are settled in cash upon vesting.

At June 30, 2015, EPCO's significant long-term incentive plans applicable to us were the Enterprise Products 1998 Long-Term Incentive Plan ("1998 Plan") and the 2008 Enterprise Products Long-Term Incentive Plan (Third Amendment and Restatement) ("2008 Plan"). Up to 14,000,000 of our common units may be issued as awards under the 1998 Plan. The maximum number of common units available for issuance under the 2008 Plan was 30,000,000 at June 30, 2015. This amount will automatically increase under the terms of the 2008 Plan by 5,000,000 common units on January 1, 2016 and will continue to automatically increase annually on January 1 thereafter during the term of the 2008 Plan; provided, however, that in no event shall the maximum aggregate number exceed 70,000,000 common units. After giving effect to awards granted under the 1998 Plan and 2008 Plan through June 30, 2015, a total of 3,016,992 and 16,092,392 additional common units were available for issuance 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 fulfilling service and other conditions) once a defined vesting period expires, subject to customary forfeiture provisions. Restricted common unit awards generally vest at a rate of 25% per year beginning one year after the grant date and are non-vested until the required service periods expire. Restricted common units are included in the number of common units outstanding as 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 our common units on the date of grant. Compensation expense is recognized based on the grant date fair value, net of an allowance for estimated forfeitures, over the requisite service or vesting period.

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

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Restricted common units at December 31, 2014	4,229,790	$ 26.96
Vested	(1,940,044)	$ 25.96
Forfeited	(111,250)	$ 27.47
Restricted common units at June 30, 2015	2,178,496	$ 27.83

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

Each recipient of a restricted common unit award is 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 our common unitholders. These 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 our restricted common unit awards for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
Cash distributions paid to restricted common unitholders	$ 0.9	$ 1.6	$ 2.4	$ 4.1
Total intrinsic value of restricted common unit awards that vested during period	3.0	2.7	65.4	84.1

For the EPCO group of companies, the unrecognized compensation cost associated with restricted common unit awards was an aggregate $15.9 million at June 30, 2015, of which our allocated share of the cost is currently estimated to be $13.5 million. Due to the graded vesting provisions of these awards, we expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 1.2 years.

Unit Option Awards

EPCO's long-term incentive plans provide for the issuance of non-qualified incentive options denominated in our common units. 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, 2014 will expire on December 31, 2015). 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 following table presents unit option award activity for the period indicated:

	Number of Units (1)	Weighted-Average Strike Price (dollars/unit)	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (2)
Unit option awards at December 31, 2014	1,270,000	$ 16.14		
Exercised	(1,060,000)	$ 16.14		
Unit option awards at June 30, 2015	210,000	$ 16.14	0.5	$ 2.9

(1) All of the unit option awards outstanding at June 30, 2015 were exercisable. None of the unit option awards outstanding at December 31, 2014 were exercisable.
(2) Aggregate intrinsic value reflects fully vested unit option awards at the dates indicated.

In order to fund its unit option award-related obligations, EPCO may purchase common units at fair value either in the open market or directly from us. When employees exercise unit option awards, we reimburse EPCO for the cash difference between the strike price paid by the employee and the actual purchase price paid by EPCO for the units issued to the employee.

The following table presents supplemental information regarding unit option awards during the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
Total intrinsic value of unit option awards exercised during period	$ 2.2	$ 2.8	$ 19.6	$ 57.5
Cash received from EPCO in connection with the exercise of unit option awards	1.2	1.6	11.3	33.4
Unit option award-related cash reimbursements to EPCO	2.2	2.8	19.6	57.5

As of June 30, 2015, all compensation expense related to unit option awards had been recognized.

Phantom Unit Awards

Phantom unit awards allow recipients to acquire our common units (at no cost to the recipient apart from fulfilling service and other conditions) once a defined vesting period expires, subject to customary forfeiture provisions. Phantom unit awards generally vest at a rate of 25% per year beginning one year after the grant date and are non-vested until the required service periods expire.

At June 30, 2015, substantially all of our phantom unit awards are expected to result in the issuance of common units upon vesting; therefore, the applicable awards are accounted for as equity-classified awards. The grant date fair value of a phantom unit award is based on the market price per unit of our common units 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 phantom unit award activity for the period indicated:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Phantom unit awards at December 31, 2014	3,342,390	$ 33.13
Granted (2)	3,449,240	$ 34.05
Vested	(846,990)	$ 33.08
Forfeited	(133,334)	$ 33.40
Phantom unit awards at June 30, 2015	5,811,306	$ 33.67

(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 phantom unit awards issued during 2015 was $117.4 million based on a grant date market price of our common units ranging from $33.72 to $34.40 per unit. An estimated annual forfeiture rate of 3.5% was applied to these awards.

Our long-term incentive plans provide for the issuance of distribution equivalent rights ("DERs") in connection with phantom unit awards. A DER entitles the participant to nonforfeitable cash payments equal to the product of the number of phantom unit awards outstanding for the participant and the cash distribution per common unit paid to our common unitholders. Cash payments made in connection with DERs are charged to partners' equity when the phantom unit award is expected to result in the issuance of common units; otherwise, such amounts are expensed.

The following table presents supplemental information regarding our phantom unit awards and DERs for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
Cash payments made in connection with DERs	$ 2.2	$ 1.2	$ 3.4	$ 1.2
Total intrinsic value of phantom unit awards that vested during period	2.1	1.2	28.7	1.2

For the EPCO group of companies, the unrecognized compensation cost associated with phantom unit awards was $123.3 million at June 30, 2015, of which our allocated share of the cost is currently estimated to be $113.7 million. Due to the graded vesting provisions of these awards, we expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.1 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.

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. At December 31, 2014, we did not have any interest rate hedging derivative instruments outstanding. The following table summarizes our portfolio of interest rate swaps at June 30, 2015:

Hedged Transaction	Number and Type of Derivatives Outstanding	Notional Amount	Period of Hedge	Rate Swap	Accounting Treatment
Senior Notes OO	10 fixed-to-floating swaps	$ 750.0	5/2015 to 5/2018	1.65% to 0.76%	Fair value hedge

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.

Commodity Hedging Activities

The prices of natural gas, NGLs, crude oil, refined products and petrochemical products are subject to fluctuations in response to changes in supply and demand, market conditions and a variety of additional factors that are beyond our control. In order to manage such price risks, we enter into commodity derivative instruments such as physical forward contracts, futures contracts, fixed-for-float swaps, basis swaps and option contracts. The following table summarizes our portfolio of commodity derivative instruments outstanding at June 30, 2015 (volume measures as noted):

	Volume (1)		**Accounting**
Derivative Purpose	**Current** (2)	**Long-Term** (2)	**Treatment**
Derivatives designated as hedging instruments:			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction (Bcf)	10.0	n/a	Cash flow hedge
Forecasted sales of NGLs (MMBbls) (3)	2.4	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchases of NGLs (MMBbls)	0.2	n/a	Cash flow hedge
Forecasted sales of octane enhancement products (MMBbls)	1.2	n/a	Cash flow hedge
Natural gas marketing:			
Forecasted purchases of natural gas for fuel (Bcf)	11.1	n/a	Cash flow hedge
Forecasted sales of natural gas (Bcf)	0.3	n/a	Cash flow hedge
Natural gas storage inventory management activities (Bcf)	9.3	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	27.5	n/a	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	32.1	n/a	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products (MMBbls)	4.9	n/a	Cash flow hedge
Forecasted sales of refined products (MMBbls)	1.5	n/a	Cash flow hedge
Refined products inventory management activities (MMBbls)	3.0	n/a	Fair value hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	7.8	0.8	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	10.6	0.8	Cash flow hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (Bcf) (4,5)	81.3	10.0	Mark-to-market
NGL risk management activities (MMBbls) (5)	8.2	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (5)	4.9	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 December 2016, April 2016 and March 2018, respectively.
(3) Forecasted sales of NGL volumes under natural gas processing exclude 1.3 MMBbls of additional hedges executed under contracts that have been designated as normal sales agreements.
(4) Current volumes include 55.2 Bcf of physical derivative instruments that are predominantly priced at a marked-based index plus a premium or minus a discount related to location differences.
(5) Reflects the use of derivative instruments to manage risks associated with transportation, processing and storage assets.

At June 30, 2015, our predominant commodity hedging strategies consisted of (i) hedging anticipated future purchases and sales of commodity products associated with transportation, storage and blending activities, (ii) hedging natural gas processing margins and (iii) hedging the fair value of commodity products held in inventory.

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

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

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

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

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

	Asset Derivatives				Liability Derivatives			
	June 30, 2015		December 31, 2014		June 30, 2015		December 31, 2014	
	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	$ 5.7	Other current assets	$ --	Other current liabilities	$ --	Other current liabilities	$ --
Interest rate derivatives	Other assets	--	Other assets	--	Other liabilities	5.5	Other liabilities	--
Total interest rate derivatives		5.7		--		5.5		--
Commodity derivatives	Other current assets	117.6	Other current assets	217.9	Other current liabilities	121.0	Other current liabilities	145.3
Commodity derivatives	Other assets	0.5	Other assets	--	Other liabilities	0.7	Other liabilities	--
Total commodity derivatives		118.1		217.9		121.7		145.3
Total derivatives designated as hedging instruments		$ 123.8		$ 217.9		$ 127.2		$ 145.3
Derivatives not designated as hedging instruments								
Commodity derivatives	Other current assets	$ 13.8	Other current assets	$ 8.1	Other current liabilities	$ 8.2	Other current liabilities	$ 0.7
Commodity derivatives	Other assets	0.4	Other assets	0.6	Other liabilities	1.4	Other liabilities	1.4
Total commodity derivatives		$ 14.2		$ 8.7		$ 9.6		$ 2.1

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

	Offsetting of Financial Assets and Derivative Assets						
				Gross Amounts Not Offset in the Balance Sheet			
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Amounts of Assets Presented in the Balance Sheet	Financial Instruments	Cash Collateral Received	Cash Collateral Paid	Amounts That Would Have Been Presented On Net Basis
	(i)	(ii)	(iii) = (i) – (ii)	(iv)			(v) = (iii) + (iv)
As of June 30, 2015:							
Interest rate derivatives	$ 5.7	$ --	$ 5.7	$ (5.5)	$ --	$ --	$ 0.2
Commodity derivatives	132.3	--	132.3	(111.7)	(4.0)	--	16.6
As of December 31, 2014:							
Commodity derivatives	$ 226.6	$ --	$ 226.6	$ (147.3)	$ (23.9)	$ --	$ 55.4

	Offsetting of Financial Liabilities and Derivative Liabilities					
				Gross Amounts Not Offset in the Balance Sheet		
	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Balance Sheet	Amounts of Liabilities Presented in the Balance Sheet	Financial Instruments	Cash Collateral Paid	Amounts That Would Have Been Presented On Net Basis
	(i)	(ii)	(iii) = (i) – (ii)	(iv)		(v) = (iii) + (iv)
As of June 30, 2015:						
Interest rate derivatives	$ 5.5	$ --	$ 5.5	$ (5.5)	$ --	$ --
Commodity derivatives	131.3	--	131.3	(111.7)	--	19.6
As of December 31, 2014:						
Commodity derivatives	$ 147.4	$ --	$ 147.4	$ (147.3)	$ --	$ 0.1

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NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Derivative assets and liabilities recorded on our Unaudited Condensed Consolidated Balance Sheets are presented on a gross-basis and determined at the individual transaction level. 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 these tables, but only to the extent that it represents variation margins. Any amounts associated with derivative prepayments or initial margins that are not influenced by the derivative asset or liability amounts or those that are determined solely on their volumetric notional amounts are excluded from these tables.

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

Derivatives in Fair Value Hedging Relationships	Location	Gain (Loss) Recognized in Income on Derivative			
		For the Three Months Ended June 30,		For the Six Months Ended June 30,	
		2015	2014	2015	2014
Interest rate derivatives	Interest expense	$ (0.8)	$ (2.5)	$ (0.8)	$ (5.4)
Commodity derivatives	Revenue	(0.3)	1.3	0.4	0.9
Total		$ (1.1)	$ (1.2)	$ (0.4)	$ (4.5)

Derivatives in Fair Value Hedging Relationships	Location	Gain (Loss) Recognized in Income on Hedged Item			
		For the Three Months Ended June 30,		For the Six Months Ended June 30,	
		2015	2014	2015	2014
Interest rate derivatives	Interest expense	$ 0.5	$ 2.5	$ 0.5	$ 5.4
Commodity derivatives	Revenue	1.3	(1.0)	9.9	(2.4)
Total		$ 1.8	$ 1.5	$ 10.4	$ 3.0

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 indicated:

Derivatives in Cash Flow Hedging Relationships	Change in Value Recognized in Other Comprehensive Income (Loss) on Derivative (Effective Portion)			
	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
Commodity derivatives – Revenue (1)	$ (6.1)	$ (32.9)	$ 26.5	$ (43.6)
Commodity derivatives – Operating costs and expenses (1)	1.8	0.1	--	1.6
Total	$ (4.3)	$ (32.8)	$ 26.5	$ (42.0)

(1) The fair value of these derivative instruments will be reclassified to their respective locations on the Unaudited Condensed 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 June 30,		For the Six Months Ended June 30,	
		2015	2014	2015	2014
Interest rate derivatives	Interest expense	$ (8.7)	$ (8.0)	$ (17.4)	$ (15.9)
Commodity derivatives	Revenue	20.7	(15.4)	81.8	(32.3)
Commodity derivatives	Operating costs and expenses	(0.5)	0.5	(0.5)	1.4
Total		$ 11.5	$ (22.9)	$ 63.9	$ (46.8)

Derivatives in Cash Flow Hedging Relationships	Location	Gain (Loss) Recognized in Income on Derivative (Ineffective Portion)			
		For the Three Months Ended June 30,		For the Six Months Ended June 30,	
		2015	2014	2015	2014
Commodity derivatives	Revenue	$ 0.1	$ 0.1	$ 0.4	$ (0.1)
Commodity derivatives	Operating costs and expenses	--	(0.1)	--	0.1
Total		$ 0.1	$ --	$ 0.4	$ --

Over the next twelve months, we expect to reclassify $36.3 million of losses attributable to interest rate derivative instruments from accumulated other comprehensive loss to earnings as an increase in interest expense. Likewise, we expect to reclassify $15.4 million of net gains attributable to commodity derivative instruments from accumulated other comprehensive income to earnings, $15.0 million as an increase in revenue and $0.4 million as a decrease in operating costs and expenses.

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

Derivatives Not Designated as Hedging Instruments	Location	Gain (Loss) Recognized in Income on Derivative			
		For the Three Months Ended June 30,		For the Six Months Ended June 30,	
		2015	2014	2015	2014
Interest rate derivatives	Interest expense	$ --	$ --	$ --	$ (0.1)
Commodity derivatives	Revenue	4.2	(6.6)	3.9	(27.6)
Commodity derivatives	Operating costs and expenses	0.3	--	0.3	--
Total		$ 4.5	$ (6.6)	$ 4.2	$ (27.7)

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

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

Recurring Fair Value Measurements

The following tables set forth, by level within the fair value hierarchy, the carrying values of our financial assets and liabilities at the dates indicated. 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.

	June 30, 2015 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)	Total
Financial assets:				
Interest rate derivatives	$ --	$ 5.7	$ --	$ 5.7
Commodity derivatives	17.0	114.5	0.8	132.3
Total	$ 17.0	$ 120.2	$ 0.8	$ 138.0
Financial liabilities:				
Liquidity Option Agreement	$ --	$ --	$ 223.7	$ 223.7
Interest rate derivatives	--	5.5	--	5.5
Commodity derivatives	21.9	107.0	2.4	131.3
Total	$ 21.9	$ 112.5	$ 226.1	$ 360.5

	December 31, 2014 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)	Total
Financial assets:				
Commodity derivatives	$ 37.8	$ 187.8	$ 1.0	$ 226.6
Financial liabilities:				
Liquidity Option Agreement	$ --	$ --	$ 212.2	$ 212.2
Commodity derivatives	13.8	133.0	0.6	147.4
Total	$ 13.8	$ 133.0	$ 212.8	$ 359.6

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

	Location	For the Six Months Ended June 30, 2015	2014
Financial asset (liability) balance, net, January 1		$ (211.8)	$ 3.2
Total gains (losses) included in:			
Net income (1)	Revenue	(0.4)	4.6
Other comprehensive income	Commodity derivative instruments – changes in fair value of cash flow hedges	(1.5)	--
Settlements	Revenue	(0.5)	(0.1)
Transfers out of Level 3		0.1	--
Financial asset (liability) balance, net, March 31		(214.1)	7.7
Total gains (losses) included in:			
Net income (1)	Revenue	(0.4)	(3.3)
Net income	Other expense, net	(11.5)	--
Other comprehensive income	Commodity derivative instruments – changes in fair value of cash flow hedges	(1.0)	--
Settlements	Revenue	0.2	(1.8)
Transfers out of Level 3		1.5	--
Financial asset (liability) balance, net, June 30		$ (225.3)	$ 2.6

(1) There were $0.1 million and $1.1 million of unrealized losses included in these amounts for the three and six months ended June 30, 2015, respectively. There were unrealized losses of $5.0 million and $0.5 million included in these amounts for the three and six months ended June 30, 2014, respectively.

The following table provides quantitative information about our recurring Level 3 fair value measurements at June 30, 2015:

	Fair Value: Financial Assets	Fair Value: Financial Liabilities	Valuation Techniques	Unobservable Input	Range
Commodity derivatives – Crude oil	$ 0.6	$ 1.1	Discounted cash flow	Forward commodity prices	$58.95-$61.58/barrel
Commodity derivatives – Natural gasoline	0.2	1.3	Discounted cash flow	Forward commodity prices	$1.25-$1.27/gallon
Total	$ 0.8	$ 2.4			

With respect to commodity derivatives, we believe forward commodity prices are the most significant unobservable inputs in determining our Level 3 recurring fair value measurements at June 30, 2015. 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.

As described in Note 15, we adjusted the expected life of OTA following exercise of the Liquidity Option Agreement to reflect an equal probability of the dissolution of OTA over each of the 30 years in our forecast period. None of the other key valuation assumptions we listed in our 2014 Form 10-K for the Liquidity Option Agreement have changed.

Nonrecurring Fair Value Measurements

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

	For the Three Months Ended June 30, 2015	2014	For the Six Months Ended June 30, 2015	2014
NGL Pipelines & Services	$ 5.2	$ 2.8	$ 6.0	$ 5.4
Crude Oil Pipelines & Services	18.1	0.8	25.9	1.8
Natural Gas Pipelines & Services	0.8	0.1	21.5	0.3
Petrochemical & Refined Products Services	--	--	0.4	5.0
Offshore Pipelines & Services	54.9	--	58.5	--
Total	$ 79.0	$ 3.7	$ 112.3	$ 12.5

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

Our non-cash asset impairment charges for the six months ended June 30, 2015 primarily reflect the write-down of a long-lived asset of our Offshore Business classified as held for sale (see Note 6) and the abandonment of certain natural gas and crude oil pipeline assets in Texas. The following table summarizes our non-recurring fair value measurements for the six months ended June 30, 2015:

		Fair Value Measurements Using			
	Carrying Value at June 30, 2015	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Non-Cash Impairment Loss
Impairment of long-lived assets disposed of other than by sale	$ --	$ --	$ --	$ --	$ 55.1
Impairment of long-lived assets to be disposed of by sale (1)	1,689.4	--	--	1,689.4	57.2
Total					$ 112.3

(1) Primarily includes long-lived assets of our Offshore Business that were reclassified to held for sale at June 30, 2015, net of an associated non-cash impairment charge of $54.8 million related to goodwill. See Note 6.

Our non-cash asset impairment charges for the six months ended June 30, 2014 primarily reflect the abandonment of assets classified as property, plant and equipment. The following table summarizes our non-recurring fair value measurements for the six months ended June 30, 2014:

		Fair Value Measurements Using			
	Carrying Value at June 30, 2014	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Non-Cash Impairment Loss
Impairment of long-lived assets disposed of other than by sale	$ --	$ --	$ --	$ --	$ 7.5
Impairment of long-lived assets to be disposed of by sale	0.1	--	--	0.1	5.0
Total					$ 12.5

Other Fair Value Information

The carrying amounts of cash and cash equivalents (including restricted cash balances), accounts receivable, commercial paper notes and accounts payable approximate their fair values based on their short-term nature. The estimated total fair value of our fixed-rate debt obligations was $23.05 billion and $22.16 billion at June 30, 2015 and December 31, 2014, respectively. The aggregate carrying value of these debt obligations was $22.33 billion and $20.48 billion at June 30, 2015 and December 31, 2014, 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 inventory amounts by product type were as follows at the dates indicated:

	June 30, 2015	December 31, 2014
NGLs	$ 586.8	$ 579.1
Petrochemicals and refined products	220.4	295.6
Crude oil	157.9	97.8
Natural gas	34.7	41.7
Total	$ 999.8	$ 1,014.2

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. The following table presents our total cost of sales amounts and lower of cost or market adjustments for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
Cost of sales (1)	$ 5,257.9	$ 10,705.3	$ 10,936.0	$ 21,758.0
Lower of cost or market adjustments	0.5	2.7	4.0	7.9

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

Note 6. Assets Held for Sale

Offshore Gulf of Mexico Business

On July 16, 2015, we announced the execution of a Purchase and Sale Agreement with Genesis whereby they agreed to acquire our Offshore Business, which primarily consists of our Offshore Pipelines & Services business segment, for approximately $1.53 billion in cash. Our Offshore Business served drilling and development regions, including deepwater production fields, in the northern Gulf of Mexico offshore Texas, Louisiana, Mississippi and Alabama. As of December 31, 2014, our Offshore Business included approximately 2,350 miles of offshore natural gas and crude oil pipelines and six offshore hub platforms. The transaction closed on July 24, 2015. We maintained ownership of this business until the closing date.

We viewed our Offshore Business as an extension of our midstream energy services network. As such, the sale of these assets does not represent a strategic shift in our consolidated operations that would have a major effect on our operations and financial results. At December 31, 2014 and June 30, 2015, segment assets for our Offshore Pipelines & Services segment represented 4.3% and 4.1%, respectively, of consolidated total segment assets. Likewise, gross operating margin from this business segment represented only 3.1% and 3.4% of our consolidated total gross operating margin for the year ended December 31, 2014 and six months ended June 30, 2015, respectively. The sale of this non-strategic business allows us to redeploy capital to other business opportunities that we believe will generate a higher return for us in the future (e.g., our recent acquisition of EFS Midstream LLC (see Note 18)). Also, proceeds from the closing of this sale will reduce our need to issue additional equity to support our ongoing capital spending program.

Given the status of negotiations as of June 30, 2015, this transaction met the criteria necessary to classify the underlying assets and liabilities of our Offshore Business as "held for sale." As a result, the associated assets and liabilities of this business were reclassified to current assets and current liabilities, respectively, on our Unaudited Condensed Consolidated Balance Sheet at June 30, 2015. In addition, the noncontrolling interest attributable to this held for sale business was also identified within equity at June 30, 2015.

We recorded a non-cash asset impairment charge at June 30, 2015 of approximately $54.8 million, which reflects the excess of the net assets of the business at June 30, 2015 over its estimated fair value based on the transaction price.

Since the fixed and intangible assets of our Offshore Business were classified as held for sale at June 30, 2015, we no longer depreciate and amortize the subject assets. Our consolidated results of operations for the six months ended June 30, 2015 and 2014 included $44.6 million and $45.9 million, respectively, of depreciation and amortization expense attributable to these assets.

Carrying Values of Major Classes of Assets and Liabilities Designated as Held for Sale

The following table presents the major classes of assets and liabilities designated as held for sale on our Unaudited Condensed Consolidated Balance Sheet at June 30, 2015:

	Offshore Gulf of Mexico Business
Assets held for sale:	
Current assets	$ 26.9
Property, plant and equipment, net	1,135.9
Investments in unconsolidated affiliates	482.4
Intangible assets, net	37.1
Goodwill	82.0
Other assets	1.2
Subtotal	1,765.5
Impairment charge related to goodwill	(54.8)
Total presented in Current Assets	$ 1,710.7
Liabilities related to assets held for sale:	
Current liabilities	$ 24.1
Other long-term liabilities	92.3
Total presented in Current Liabilities	$ 116.4
Noncontrolling interests in assets held for sale	$ 62.2
Net assets of Offshore Business before impairment charge	$ 1,586.9
Fair value of Offshore Business based on estimated transaction price	$ 1,532.1

Note 7. Property, Plant and Equipment

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

	Estimated Useful Life in Years	June 30, 2015	December 31, 2014
Plants, pipelines and facilities (1)	3-45 (6)	$ 31,449.8	$ 30,834.9
Underground and other storage facilities (2)	5-40 (7)	2,726.6	2,584.2
Platforms and facilities (3)	20-31	659.7	659.7
Transportation equipment (4)	3-10	159.0	154.2
Marine vessels (5)	15-30	826.1	796.4
Land		261.2	262.6
Construction in progress		3,588.2	2,754.7
Total historical cost of property, plant and equipment		39,670.6	38,046.7
Less accumulated depreciation		8,750.9	8,165.1
Subtotal property, plant and equipment, net		30,919.7	29,881.6
Carrying values reclassified to assets held for sale (8)		(1,135.9)	--
Total property, plant and equipment, net		$ 29,783.8	$ 29,881.6

(1) Plants, pipelines and facilities 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 included offshore platforms and related facilities and other associated assets located in the Gulf of Mexico (see Note 6).

(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.

(8) See Note 6 regarding the reclassification of $1.84 billion of offshore Gulf of Mexico property, plant and equipment values, net of $706.8 million of accumulated depreciation, to assets held for sale at June 30, 2015.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
Depreciation expense (1)	$ 292.6	$ 271.0	$ 583.9	$ 538.9
Capitalized interest (2)	35.7	17.7	65.3	36.2

(1) Depreciation expense is a component of “Costs and expenses” as presented on our Unaudited Condensed Statements of Consolidated Operations.

(2) We capitalize interest costs incurred on funds used to construct property, plant and equipment while the asset is in its construction phase. The capitalized interest is recorded as part of the asset to which it relates and is amortized over the asset’s estimated useful life as a component of depreciation expense. When capitalized interest is recorded, it reduces interest expense from what it would be otherwise.

At June 30, 2015, the net carrying values of property, plant and equipment attributable to our Offshore Business were reclassified to “Assets held for sale” as discussed in Note 6. Since these assets are classified as held for sale, we will no longer depreciate the underlying historical costs after June 30, 2015. For the three and six months ended June 30, 2015, we recognized $19.7 million and $40.1 million, respectively, of depreciation expense associated with these held for sale assets. Likewise, for the three and six months ended June 30, 2014, we recognized $20.4 million and $40.8 million, respectively, of depreciation expense associated with these assets.

Asset Retirement Obligations

We record asset retirement obligations ("AROs") in connection with legal requirements to perform specified retirement activities under contractual arrangements and/or governmental regulations. Our contractual AROs primarily result from right-of-way agreements associated with our pipeline operations and real estate leases associated with our plant sites. In addition, we record AROs in connection with governmental regulations associated with the abandonment or retirement of (i) above-ground brine storage pits, (ii) offshore Gulf of Mexico platform and pipeline assets and (iii) certain marine vessels. We also record AROs in connection with regulatory requirements associated with the renovation or demolition of certain assets containing hazardous substances such as asbestos. We typically fund our AROs using cash flow from operations.

Property, plant and equipment at June 30, 2015 and December 31, 2014 includes $16.9 million and $31.3 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset.

The following table presents information regarding our AROs since December 31, 2014:

ARO liability balance, December 31, 2014	$ 98.3
Liabilities incurred	0.1
Liabilities settled	(5.5)
Revisions in estimated cash flows	49.0
Accretion expense	3.1
Reclassification of Offshore Business AROs to "Liabilities related to assets held for sale"	(90.9)
ARO liability balance, June 30, 2015	$ 54.1

Our AROs related to the Matagorda Gathering System, which is located in Texas state waters in the Matagorda Island area, increased $39.5 million in the second quarter of 2015 due to a change in management estimate associated with pending and future pipeline abandonment activities. In June 2015, we were notified by the U.S. Army Corps of Engineers (the "CoE") to fully remove two pipeline segments included in this system that we had originally requested to abandon in-place. As a result, we adjusted the ARO liabilities for those pipeline segments under CoE jurisdiction to account for the estimated cost of removal. All ARO liabilities related to our Offshore Business (including those of the Matagorda Gathering System) were reclassified to "Liabilities related to assets held for sale" as presented on our Unaudited Condensed Consolidated Balance Sheet at June 30, 2015. The total amount reclassified was $90.9 million.

With respect to our AROs, the following table presents our forecast of accretion expense for the periods indicated (excluding those classified as held for sale at June 30, 2015):

Remainder of 2015	2016	2017	2018	2019
$ 1.8	$ 3.5	$ 3.8	$ 4.1	$ 4.4

Certain of our unconsolidated affiliates have AROs recorded at June 30, 2015 and December 31, 2014 relating to contractual agreements and regulatory requirements. These amounts are immaterial to our consolidated financial statements.

Note 8. Investments in Unconsolidated Affiliates

The following table presents our investments in unconsolidated affiliates by business segment at the dates indicated. We account for these investments using the equity method.

	Ownership Interest at June 30, 2015	June 30, 2015	December 31, 2014
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C.	13.1%	$ 27.1	$ 27.7
K/D/S Promix, L.L.C.	50%	43.8	38.5
Baton Rouge Fractionators LLC	32.2%	18.2	18.8
Skelly-Belvieu Pipeline Company, L.L.C.	50%	40.2	40.1
Texas Express Pipeline LLC	35%	345.8	349.3
Texas Express Gathering LLC	45%	37.3	37.9
Front Range Pipeline LLC	33.3%	171.1	170.0
Crude Oil Pipelines & Services:			
Seaway Crude Pipeline Company LLC	50%	1,420.0	1,431.2
Eagle Ford Pipeline LLC	50%	378.1	336.5
Eagle Ford Terminals Corpus Christi LLC (1)	50%	20.2	--
Natural Gas Pipelines & Services:			
White River Hub, LLC	50%	23.2	23.2
Delaware Basin Gas Processing LLC (2)	50%	7.9	--
Petrochemical & Refined Products Services:			
Baton Rouge Propylene Concentrator, LLC	30%	6.1	6.5
Centennial Pipeline LLC (“Centennial”)	50%	65.9	66.1
Other	Various	2.3	2.5
Offshore Pipelines & Services:			
Poseidon Oil Pipeline Company, L.L.C. (“Poseidon”)	36%	28.0	31.8
Cameron Highway Oil Pipeline Company	50%	195.5	201.3
Deepwater Gateway, L.L.C.	50%	77.5	79.6
Neptune Pipeline Company, L.L.C.	25.7%	33.1	34.9
Southeast Keathley Canyon Pipeline Company L.L.C.	50%	148.3	146.1
Subtotal		3,089.6	3,042.0
Less carrying values reclassified to assets held for sale (3)		(482.4)	--
Total investments in unconsolidated affiliates		$ 2,607.2	$ 3,042.0

(1) New joint venture formed with Plains Marketing, L.P., a subsidiary of Plains All American Pipeline, L.P., in March 2015 to construct and operate a marine terminal that will handle crude oil delivered by Eagle Ford Pipeline LLC.
(2) New joint venture formed with Oxy Delaware Basin Plant, LLC, a subsidiary of Occidental Petroleum Corporation, in April 2015 that will plan, design and construct a new cryogenic natural gas processing plant to accommodate the growing production of NGL-rich natural gas in the Delaware Basin.
(3) At June 30, 2015, the carrying values of our investments in unconsolidated affiliates classified within the Offshore Pipelines & Services segment were reclassified to “Assets held for sale” as discussed in Note 6.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
NGL Pipelines & Services	$ 12.5	$ 6.1	$ 24.1	$ 7.5
Crude Oil Pipelines & Services	79.4	42.2	139.3	84.9
Natural Gas Pipelines & Services	1.0	0.9	1.9	1.8
Petrochemical & Refined Products Services	(3.7)	(6.5)	(7.1)	(6.1)
Offshore Pipelines & Services	21.0	7.6	41.2	18.7
Total	$ 110.2	$ 50.3	$ 199.4	$ 106.8

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

	June 30, 2015	December 31, 2014
NGL Pipelines & Services	$ 25.9	$ 26.5
Crude Oil Pipelines & Services	21.2	21.7
Petrochemical & Refined Products Services	2.4	2.4
Offshore Pipelines & Services (1)	--	9.0
Total	$ 49.5	$ 59.6

(1) Balance at June 30, 2015 was reclassified to assets held for sale (see Note 6).

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
NGL Pipelines & Services	$ 0.3	$ 0.4	$ 0.6	$ 0.7
Crude Oil Pipelines & Services	0.2	0.1	0.5	0.3
Petrochemical & Refined Products Services	--	0.1	--	0.1
Offshore Pipelines & Services	0.8	0.3	2.8	0.5
Total	$ 1.3	$ 0.9	$ 3.9	$ 1.6

Other

The credit agreements of Poseidon and Centennial restrict their ability to pay cash dividends if a default or event of default (as defined in each credit agreement) has occurred and is continuing at the time such payments are scheduled to be paid. These businesses were in compliance with the terms of their credit agreements at June 30, 2015.

Note 9. Intangible Assets and Goodwill

Intangible Assets

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

	June 30, 2015			December 31, 2014		
	Gross Value	Accumulated Amortization	Carrying Value	Gross Value	Accumulated Amortization	Carrying Value
NGL Pipelines & Services:						
Customer relationship intangibles	$ 340.8	$ (191.1)	$ 149.7	$ 340.8	$ (183.2)	$ 157.6
Contract-based intangibles	283.0	(186.1)	96.9	277.7	(178.7)	99.0
IDRs (1)	--	--	--	432.6	--	432.6
Segment total	623.8	(377.2)	246.6	1,051.1	(361.9)	689.2
Crude Oil Pipelines & Services:						
Customer relationship intangibles	1,108.0	(12.9)	1,095.1	1,108.0	(7.7)	1,100.3
Contract-based intangibles	281.4	(41.6)	239.8	281.4	(13.5)	267.9
IDRs (1)	--	--	--	855.4	--	855.4
Segment total	1,389.4	(54.5)	1,334.9	2,244.8	(21.2)	2,223.6
Natural Gas Pipelines & Services:						
Customer relationship intangibles	1,163.6	(320.9)	842.7	1,163.6	(308.9)	854.7
Contract-based intangibles	466.0	(355.6)	110.4	466.0	(347.8)	118.2
Segment total	1,629.6	(676.5)	953.1	1,629.6	(656.7)	972.9
Petrochemical & Refined Products Services:						
Customer relationship intangibles	198.4	(45.9)	152.5	198.4	(43.3)	155.1
Contract-based intangibles	56.3	(9.9)	46.4	56.3	(7.8)	48.5
IDRs (1)	--	--	--	171.2	--	171.2
Segment total	254.7	(55.8)	198.9	425.9	(51.1)	374.8
Offshore Pipelines & Services:						
Customer relationship intangibles	195.8	(159.4)	36.4	195.8	(154.9)	40.9
Contract-based intangibles	1.2	(0.5)	0.7	1.2	(0.5)	0.7
Segment total	197.0	(159.9)	37.1	197.0	(155.4)	41.6
Subtotal all segments	4,094.5	(1,323.9)	2,770.6	5,548.4	(1,246.3)	4,302.1
Less carrying values reclassified to assets held for sale (2)	(197.0)	159.9	(37.1)	--	--	--
Total intangible assets	$ 3,897.5	$ (1,164.0)	2,733.5	$ 5,548.4	$ (1,246.3)	$ 4,302.1

(1) At December 31, 2014, we had indefinite-lived intangible assets outstanding with a carrying value of $1.46 billion recorded in connection with our acquisition of the Oiltanking IDRs in October 2014. The IDRs represented contractual rights to future cash incentive distributions to be paid by Oiltanking. In February 2015 (following completion of Step 2 of the Oiltanking acquisition), the Oiltanking IDRs were cancelled and the carrying value of the IDRs were reclassified to goodwill.
(2) At June 30, 2015, the carrying values of our intangible assets classified within the Offshore Pipelines & Services segment were reclassified to “Assets held for sale” as discussed in Note 6. Since these assets are classified as held for sale, we no longer amortize the underlying gross values after June 30, 2015.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
NGL Pipelines & Services	$ 7.7	$ 8.7	$ 15.2	$ 17.3
Crude Oil Pipelines & Services	16.6	0.3	33.3	0.6
Natural Gas Pipelines & Services	9.9	11.5	19.8	23.1
Petrochemical & Refined Products Services	2.3	1.5	4.7	3.1
Offshore Pipelines & Services	2.2	2.5	4.5	5.1
Total	$ 38.7	$ 24.5	$ 77.5	$ 49.2

The following table presents a forecast of amortization expense associated with our intangible assets for the periods indicated (excluding those classified as held for sale at June 30, 2015):

Remainder of 2015	2016	2017	2018	2019
$ 70.8	$ 150.5	$ 146.5	$ 139.4	$ 128.5

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 since December 31, 2014:

	NGL Pipelines & Services	Crude Oil Pipelines & Services	Natural Gas Pipelines & Services	Petrochemical & Refined Products Services	Offshore Pipelines & Services	Consolidated Total
Balance at December 31, 2014	$ 2,207.9	$ 914.3	$ 296.3	$ 792.2	$ 82.0	$ 4,292.7
Reclassification of Oiltanking IDR balances to goodwill in connection with the cancellation of such rights in February 2015 and other adjustments	432.6	850.7	--	170.8	--	1,454.1
Goodwill reclassified to assets held for sale	--	--	--	--	(82.0)	(82.0)
Balance at June 30, 2015	$ 2,640.5	$ 1,765.0	$ 296.3	$ 963.0	$ --	$ 5,664.8

Upon completion of Step 2 of the Oiltanking acquisition in February 2015, the IDRs of Oiltanking were cancelled and the associated carrying values were reclassified from intangible assets to goodwill and allocated to the appropriate business segments.

During the second quarter of 2015, we retrospectively adjusted our provisional fair value estimate of the Liquidity Option Agreement by $92.8 million, with a corresponding increase to goodwill, which was allocated to the appropriate business segments at December 31, 2014 as follows: $27.5 million to NGL Pipelines & Services; $54.4 million to Crude Oil Pipelines & Services; and $10.9 million to Petrochemical & Refined Products Services. See Note 15 for additional information regarding this change.

At June 30, 2015, we reclassified $82.0 million of goodwill attributable to our Offshore Pipelines & Services segment to assets held for sale (see Note 6).

Note 10. Debt Obligations

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

	June 30, 2015	December 31, 2014
EPO senior debt obligations:		
Commercial Paper Notes, variable-rates	$ --	$ 906.5
Senior Notes I, 5.00% fixed-rate, due March 2015	--	250.0
Senior Notes X, 3.70% fixed-rate, due June 2015	--	400.0
Senior Notes FF, 1.25% fixed-rate, due August 2015	650.0	650.0
$1.5 Billion 364-Day Credit Agreement, variable-rate, due September 2015	--	--
Senior Notes AA, 3.20% fixed-rate, due February 2016	750.0	750.0
Senior Notes L, 6.30% fixed-rate, due September 2017	800.0	800.0
Senior Notes V, 6.65% fixed-rate, due April 2018	349.7	349.7
Senior Notes OO, 1.65% fixed-rate, due May 2018	750.0	--
$3.5 Billion Multi-Year Revolving Credit Facility, variable-rate, due June 2018	--	--
Senior Notes N, 6.50% fixed-rate, due January 2019	700.0	700.0
Senior Notes LL, 2.55% fixed-rate, due October 2019	800.0	800.0
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	1,250.0
Senior Notes JJ, 3.90% fixed-rate, due February 2024	850.0	850.0
Senior Notes MM, 3.75% fixed-rate, due February 2025	1,150.0	1,150.0
Senior Notes PP, 3.70% fixed-rate, due February 2026	875.0	--
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	1,400.0	1,400.0
Senior Notes KK, 5.10% fixed-rate, due February 2045	1,150.0	1,150.0
Senior Notes QQ, 4.90% fixed-rate, due May 2046	875.0	--
Senior Notes NN, 4.95% fixed-rate, due October 2054	400.0	400.0
TEPPCO senior debt obligations:		
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	20,800.0	19,856.5
EPO Junior Subordinated Notes A, fixed/variable-rate, due August 2066 (1)	550.0	550.0
EPO Junior Subordinated Notes C, fixed/variable-rate, due June 2067 (2)	285.8	285.8
EPO Junior Subordinated Notes B, fixed/variable-rate, due January 2068 (3)	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	22,332.7	21,389.2
Other, non-principal amounts	(39.7)	(25.4)
Less current maturities of debt (4)	(1,400.1)	(2,206.4)
Total long-term debt	$ 20,892.9	$ 19,157.4

(1) Fixed rate of 8.375% through August 1, 2016 (i.e., first call date without a make-whole redemption premium); thereafter, variable rate based on 3-month LIBOR plus 3.7075%.
(2) Fixed rate of 7.0% through September 1, 2017 (i.e., first call date without a make-whole redemption premium); thereafter, variable rate based on 3-month LIBOR plus 2.7775%.
(3) Fixed rate of 7.034% through January 15, 2018 (i.e., first call date without a make-whole redemption premium); thereafter, the rate will be the greater of 7.034% or a variable rate based on 3-month LIBOR plus 2.68%.
(4) We expect to refinance the current maturities of our debt obligations at or prior to their maturity.

The following table presents contractually scheduled maturities of our consolidated debt obligations outstanding at June 30, 2015 for the next five years, and in total thereafter:

		Scheduled Maturities of Debt					
	Total	Remainder of 2015	2016	2017	2018	2019	After 2019
Senior Notes	$ 20,800.0	$ 650.0	$ 750.0	$ 800.0	$ 1,100.0	$ 1,500.0	$ 16,000.0
Junior Subordinated Notes	1,532.7	--	--	--	--	--	1,532.7
Total	$ 22,332.7	$ 650.0	$ 750.0	$ 800.0	$ 1,100.0	$ 1,500.0	$ 17,532.7

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 immaterial 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 $2.5 Billion of Senior Notes in May 2015
In May 2015, EPO issued $750 million in principal amount of 1.65% senior notes due May 2018 ("Senior Notes OO"), $875 million in principal amount of 3.70% senior notes due February 2026 ("Senior Notes PP") and $875 million in principal amount of 4.90% senior notes due May 2046 ("Senior Notes QQ"). Senior Notes OO, PP and QQ were issued at 99.881%, 99.635% and 99.635% of their principal amounts, respectively.

Net proceeds from the issuance of these senior notes were used as follows: (i) the repayment of amounts outstanding under EPO's commercial paper program, which included amounts we used to repay $250 million in principal amount of Senior Notes I that matured in March 2015, (ii) the repayment of amounts outstanding at the maturity of our $400 million in principal amount of Senior Notes X that matured in June 2015 and (iii) for general company purposes.

Enterprise Products Partners L.P. has unconditionally guaranteed these senior notes 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 an indenture containing certain covenants, which generally restrict EPO's ability (with certain exceptions) to incur debt secured by liens and engage in sale and leaseback transactions.

Letters of Credit
At June 30, 2015, EPO had $2.5 million of letters of credit outstanding related to operations at our facilities and motor fuel tax obligations.

Lender Financial Covenants
We were in compliance with the financial covenants of our consolidated debt agreements at June 30, 2015.

Information Regarding Variable Interest Rates Paid
The following table presents the range of interest rates and weighted-average interest rates paid on our consolidated variable-rate debt during the six months ended June 30, 2015:

	Range of Interest Rates Paid	Weighted-Average Interest Rate Paid
Commercial Paper Notes	0.35% to 0.78%	0.61%
EPO $3.5 Billion Multi-Year Revolving Credit Facility	1.15% to 3.25%	1.30%

Note 11. Equity and Distributions

Partners' equity reflects the various classes of limited partner interests (i.e., common units, including restricted common units) that we have outstanding. The following table summarizes changes in the number of our outstanding units since December 31, 2014:

	Common Units (Unrestricted)	Restricted Common Units	Total Common Units
Number of units outstanding at December 31, 2014	1,933,095,027	4,229,790	1,937,324,817
Common units issued in connection with at-the-market program	23,258,453	--	23,258,453
Common units issued in connection with DRIP and EUPP	5,637,275	--	5,637,275
Common units issued in connection with Step 2 of Oiltanking acquisition	36,827,517	--	36,827,517
Common units issued in connection with the vesting and exercise of unit options	327,719	--	327,719
Common units issued in connection with the vesting of phantom unit awards	556,041	--	556,041
Common units issued in connection with the vesting of restricted common unit awards	1,940,044	(1,940,044)	--
Forfeiture of restricted common unit awards	--	(111,250)	(111,250)
Acquisition and cancellation of treasury units in connection with the vesting of equity-based awards	(662,242)	--	(662,242)
Other	15,054	--	15,054
Number of units outstanding at June 30, 2015	2,000,994,888	2,178,496	2,003,173,384

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 "2013 Shelf") on file with the SEC. The 2013 Shelf allows Enterprise Products Partners L.P. and EPO (on a standalone basis) to issue an unlimited amount of equity and debt securities, respectively.

On July 1, 2015, we filed a registration statement with the SEC covering the issuance of up to $1.92 billion of our common units in amounts, at prices and on terms to be determined by market conditions and other factors at the time of such offerings. Pursuant to this "at-the-market" program, we may sell common units under an equity distribution agreement between Enterprise Products Partners L.P. and certain broker-dealers from time-to-time by means of ordinary brokers' transactions through the NYSE at market prices, in block transactions or as otherwise agreed to with the broker-dealer parties to the agreement. The new registration statement was declared effective on August 3, 2015 and replaced our prior registration statement with respect to the at-the-market program, which was filed with the SEC in October 2013 and covered the issuance of up to $1.25 billion of our common units. Immediately prior to the effectiveness of the new registration statement, we had the capacity to issue additional common units under the at-the-market program up to an aggregate sales price of $424.6 million (after giving effect to sales of common units previously made under the program). Following the effectiveness of the new registration statement and after taking into account the aggregate sales price of common units sold under our at-the-market program through June 30, 2015 as described below, we now have the capacity to issue additional common units under our at-the-market program up to an aggregate sales price of $1.92 billion.

During the six months ended June 30, 2015, we issued 23,258,453 common units under this program for aggregate gross proceeds of $767.1 million. This includes 3,225,057 common units sold in March 2015 to a privately held affiliate of EPCO, which generated gross proceeds of $100 million. After taking into account applicable costs, our transactions under the at-the-market program resulted in aggregate net cash proceeds of $760.0 million for the first six months of 2015. During the six months ended June 30, 2014, we issued 1,590,334 common units under this program for aggregate gross cash proceeds of $58.3 million, resulting in total net cash proceeds of $57.7 million.

We also have registration statements on file with the SEC collectively authorizing the issuance of up to 140,000,000 of our common units in connection with a distribution reinvestment plan ("DRIP"). We issued a total of 5,453,541 common units under our DRIP during the six months ended June 30, 2015, which generated net cash proceeds of $177.8 million. During the six months ended June 30, 2014, we issued 4,890,878 common units under our DRIP, which generated net cash proceeds of $160.4 million. Privately held affiliates of EPCO reinvested $50 million through the DRIP in each of the six month periods ending June 30, 2015 and 2014 (this amount being a component of the net cash proceeds presented for both periods). After taking into account the number of common units issued under the DRIP through June 30, 2015, we have the capacity to issue an additional 22,027,808 common units under this plan.

In addition to the DRIP, we have registration statements on file with the SEC authorizing the issuance of up to 8,000,000 of our common units in connection with our employee unit purchase plan ("EUPP"). We issued 183,734 common units under our EUPP during the six months ended June 30, 2015, which generated net cash proceeds of $6.3 million. During the six months ended June 30, 2014, we issued 149,060 common units under our EUPP, which generated net cash proceeds of $5.2 million. After taking into account the number of common units issued under the EUPP through June 30, 2015, we may issue an additional 6,969,334 common units under this plan.

The net cash proceeds we received from the issuance of common units during the six months ended June 30, 2015 were used to temporarily reduce amounts outstanding under EPO's commercial paper program and for general company purposes.

Completion of Oiltanking Acquisition
In October 2014, we completed the first step ("Step 1") of a two-step acquisition of Oiltanking by paying approximately $4.41 billion to OTA for Oiltanking GP, the related IDRs and approximately 65.9% of the limited partner interests of Oiltanking. As a second step ("Step 2") of the Oiltanking acquisition (separately negotiated by the conflicts committee of Oiltanking GP on behalf of Oiltanking), we entered into an Agreement and Plan of Merger (the "merger agreement") with Oiltanking in November 2014 that provided for the following:

§ the merger of a wholly owned subsidiary of Enterprise with and into Oiltanking, with Oiltanking surviving the merger as a wholly owned subsidiary of Enterprise; and

§ all outstanding common units of Oiltanking at the effective time of the merger held by Oiltanking's public unitholders (which consisted of Oiltanking unitholders other than Enterprise and its subsidiaries) to be cancelled and converted into Enterprise common units based on an exchange ratio of 1.30 Enterprise common units for each Oiltanking common unit.

In accordance with the merger agreement and Oiltanking's partnership agreement, the merger was submitted to a vote of Oiltanking's common unitholders, with the required majority of unitholders (including our ownership interests) voting to approve the merger on February 13, 2015. Upon approval of the merger, a total of 36,827,517 of our common units were issued to Oiltanking's former public unitholders. With the completion of Step 2, total consideration paid by Enterprise for Oiltanking was approximately $5.9 billion.

Step 2 of the acquisition was accounted for in accordance with ASC Topic 810, *Consolidations – Overall – Changes in Parent's Ownership Interest in a Subsidiary*. Since we had a controlling financial interest in Oiltanking before and after completion of Step 2, the increase in our ownership interest in Oiltanking was accounted for as an equity transaction with no gain or loss recognized. Step 2 represented our acquisition of the noncontrolling interests in Oiltanking; therefore, approximately $1.4 billion of noncontrolling interests attributable to Oiltanking was reclassified to limited partners' equity to reflect the February 2015 issuance of 36,827,517 new common units.

See Note 15 for information regarding requests from the Federal Trade Commission ("FTC") and the Attorney General of the State of Texas in connection with the Oiltanking acquisition.

With the exception of the fair value assigned to the Liquidity Option Agreement (see Notes 4 and 15), we consider our purchase price allocation to be final. We expect to finalize the fair value of the Liquidity Option Agreement during the third quarter of 2015. Subsequent changes in the fair value of this option (other than those attributable to the finalization of the purchase price) will be recorded in earnings each reporting period until the option expires or is exercised.

Noncontrolling Interests
Noncontrolling interests represent third party equity ownership interests in our consolidated subsidiaries, including Enterprise EF78 LLC, Rio Grande Pipeline Company, Tri-States NGL Pipeline L.L.C., Panola Pipeline Company, LLC and Wilprise Pipeline Company LLC.

At June 30, 2015, third party ownership in Independence Hub LLC was classified as "noncontrolling interests in assets held for sale." Independence Hub LLC is a component of the Offshore Business that we sold to Genesis in July 2015 (see Note 6).

As previously described, we reclassified approximately $1.4 billion of noncontrolling interests to limited partners' equity in connection with completing Step 2 of the Oiltanking acquisition in February 2015. Cash distributions paid in the first quarter of 2015 to the limited partners of Oiltanking other than EPO and its subsidiaries are presented as amounts paid to noncontrolling interests.

In February 2015, we formed a joint venture involving our Panola NGL Pipeline with affiliates of Anadarko Petroleum Corporation ("Anadarko"), DCP Midstream Partners, LP ("DCP") and MarkWest Energy Partners, L.P. ("MarkWest"). We will continue to serve as operator of the Panola Pipeline and own 55% of the member interests in the joint venture. Affiliates of Anadarko, DCP and MarkWest will own the remaining 45% member interests, with each holding a 15% interest. The Panola Pipeline transports mixed NGLs from points near Carthage, Texas to Mont Belvieu, Texas and supports the Haynesville and Cotton Valley oil and gas production areas.

Accumulated Other Comprehensive Income (Loss)
The following tables present the components of accumulated other comprehensive income (loss) as reported on our Unaudited Condensed Consolidated Balance Sheets at the dates indicated:

	Gains (Losses) on Cash Flow Hedges			
	Commodity Derivative Instruments	Interest Rate Derivative Instruments	Other	Total
Balance, December 31, 2014	$ 69.9	$ (314.8)	$ 3.3	$ (241.6)
Other comprehensive income before reclassifications	26.5	--	0.4	26.9
Amounts reclassified from accumulated other comprehensive loss (income)	(81.3)	17.4	--	(63.9)
Total other comprehensive income (loss)	(54.8)	17.4	0.4	(37.0)
Balance, June 30, 2015	$ 15.1	$ (297.4)	$ 3.7	$ (278.6)

	Gains (Losses) on Cash Flow Hedges			
	Commodity Derivative Instruments	Interest Rate Derivative Instruments	Other	Total
Balance, December 31, 2013	$ (14.7)	$ (347.2)	$ 2.9	$ (359.0)
Other comprehensive income before reclassifications	(42.0)	--	--	(42.0)
Amounts reclassified from accumulated other comprehensive loss	30.9	15.9	--	46.8
Total other comprehensive income (loss)	(11.1)	15.9	--	4.8
Balance, June 30, 2014	$ (25.8)	$ (331.3)	$ 2.9	$ (354.2)

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

		For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	Location	2015	2014	2015	2014
Losses (gains) on cash flow hedges:					
Interest rate derivatives	Interest expense	$ 8.7	$ 8.0	$ 17.4	$ 15.9
Commodity derivatives	Revenue	(20.7)	15.4	(81.8)	32.3
Commodity derivatives	Operating costs and expenses	0.5	(0.5)	0.5	(1.4)
Total		$ (11.5)	$ 22.9	$ (63.9)	$ 46.8

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
2014:			
1st Quarter	$ 0.3550	4/30/2014	5/7/2014
2nd Quarter	$ 0.3600	7/31/2014	8/7/2014
2015:			
1st Quarter	$ 0.3750	4/30/2015	5/7/2015
2nd Quarter	$ 0.3800	7/31/2015	8/7/2015

Distributions paid during 2015 exclude 35,380,000 common units (the “Designated Units”) owned by a privately held affiliate of EPCO for which such affiliate has agreed to temporarily waive the regular quarterly cash distributions it would otherwise receive from us with respect thereto. The Designated Units will be entitled to receive quarterly cash distributions paid, if any, beginning in the first quarter of 2016.

Note 12. Business Segments

Our historical operations are reported under five business segments: (i) NGL Pipelines & Services, (ii) Crude Oil Pipelines & Services, (iii) Natural Gas Pipelines & Services, (iv) Petrochemical & Refined Products Services and (v) Offshore Pipelines & 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.

As discussed in Note 6, the operations presented in our Offshore Pipelines & Services business segment were classified as held for sale as of June 30, 2015. We completed the sale of our Offshore Business on July 24, 2015. We will continue to report the historical results of the Offshore Pipelines & Services segment through the closing date of the sales transaction.

Segment revenues include intersegment and intrasegment transactions, which are generally based on transactions made at market-based rates. Our consolidated revenues reflect the elimination of intercompany transactions. Substantially all of our consolidated revenues are earned in the U.S. and derived from a wide customer base.

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 executive 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.

In total, gross operating margin represents operating income exclusive of (1) depreciation, amortization and accretion expenses, (2) impairment charges, (3) gains and losses attributable to asset sales and insurance recoveries and (4) general and administrative costs. Gross operating margin includes equity in income of unconsolidated affiliates and non-refundable deferred transportation revenues relating to the make-up rights of committed shippers associated with certain pipelines. 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 consolidation. 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.

Segment assets consist of property, plant and equipment, investments in unconsolidated affiliates, intangible assets and goodwill. Segment assets exclude those amounts classified as held for sale at each balance sheet date. The carrying values of such amounts are assigned to each segment based on each asset's or investment's principal operations and contribution to the gross operating margin of that particular segment. Since construction-in-progress amounts (a component of property, plant and equipment) generally do not contribute to segment gross operating margin, such amounts are excluded from segment asset totals until the underlying assets are placed in service. Intangible assets and goodwill are assigned to each segment based on the classification of the assets to which they relate. Substantially all of our plants, pipelines and other fixed assets are located in the U.S.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
Revenues	$ 7,092.5	$ 12,520.8	$ 14,565.0	$ 25,430.7
Subtract operating costs and expenses	(6,357.5)	(11,639.1)	(12,973.9)	(23,519.6)
Add equity in income of unconsolidated affiliates	110.2	50.3	199.4	106.8
Add depreciation, amortization and accretion expense amounts not reflected in gross operating margin	385.6	312.4	730.9	613.8
Add impairment charges not reflected in gross operating margin	79.0	3.7	112.3	12.5
Add net losses or subtract net gains attributable to asset sales and insurance recoveries not reflected in gross operating margin (see Note 16)	2.5	(6.8)	2.4	(96.4)
Add non-refundable deferred revenues attributable to shipper make-up rights on new pipeline projects reflected in gross operating margin	5.2	21.9	35.9	45.2
Subtract subsequent recognition of deferred revenues attributable to make-up rights not reflected in gross operating margin	(14.3)	--	(34.4)	--
Total segment gross operating margin	$ 1,303.2	$ 1,263.2	$ 2,637.6	$ 2,593.0

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
Total segment gross operating margin	$ 1,303.2	$ 1,263.2	$ 2,637.6	$ 2,593.0
Adjustments to reconcile total segment gross operating margin to operating income:				
Subtract depreciation, amortization and accretion expense amounts not reflected in gross operating margin	(385.6)	(312.4)	(730.9)	(613.8)
Subtract impairment charges not reflected in gross operating margin	(79.0)	(3.7)	(112.3)	(12.5)
Add net gains or subtract net losses attributable to asset sales and insurance recoveries not reflected in gross operating margin	(2.5)	6.8	(2.4)	96.4
Subtract non-refundable deferred revenues attributable to shipper make-up rights on new pipeline projects reflected in gross operating margin	(5.2)	(21.9)	(35.9)	(45.2)
Add subsequent recognition of deferred revenues attributable to make-up rights not reflected in gross operating margin	14.3	--	34.4	--
Subtract general and administrative costs not reflected in gross operating margin	(44.9)	(47.7)	(94.2)	(100.9)
Operating income	800.3	884.3	1,696.3	1,917.0
Other expense, net	(251.6)	(227.8)	(490.2)	(449.0)
Income before income taxes	$ 548.7	$ 656.5	$ 1,206.1	$ 1,468.0

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	Crude Oil Pipelines & Services	Natural Gas Pipelines & Services	Petrochemical & Refined Products Services	Offshore Pipelines & Services	Adjustments and Eliminations	Consolidated Total
Revenues from third parties:							
Three months ended June 30, 2015	$ 2,263.8	$ 3,087.0	$ 681.4	$ 1,018.5	$ 34.5	$ --	$ 7,085.2
Three months ended June 30, 2014	4,019.5	5,865.6	1,034.5	1,547.3	36.6	--	12,503.5
Six months ended June 30, 2015	4,938.6	5,764.0	1,412.3	2,367.6	69.1	--	14,551.6
Six months ended June 30, 2014	9,193.2	10,801.0	2,234.5	3,077.9	71.3	--	25,377.9
Revenues from related parties:							
Three months ended June 30, 2015	2.3	1.4	3.3	--	0.3	--	7.3
Three months ended June 30, 2014	1.7	6.7	6.5	--	2.4	--	17.3
Six months ended June 30, 2015	3.8	2.4	6.3	--	0.9	--	13.4
Six months ended June 30, 2014	7.5	29.6	11.1	--	4.6	--	52.8
Intersegment and intrasegment revenues:							
Three months ended June 30, 2015	2,781.0	1,539.7	169.5	322.9	0.1	(4,813.2)	--
Three months ended June 30, 2014	3,324.9	5,634.3	295.4	428.4	1.3	(9,684.3)	--
Six months ended June 30, 2015	5,224.1	2,816.8	339.5	608.5	0.5	(8,989.4)	--
Six months ended June 30, 2014	7,185.9	8,185.0	604.8	865.4	3.6	(16,844.7)	--
Total revenues:							
Three months ended June 30, 2015	5,047.1	4,628.1	854.2	1,341.4	34.9	(4,813.2)	7,092.5
Three months ended June 30, 2014	7,346.1	11,506.6	1,336.4	1,975.7	40.3	(9,684.3)	12,520.8
Six months ended June 30, 2015	10,166.5	8,583.2	1,758.1	2,976.1	70.5	(8,989.4)	14,565.0
Six months ended June 30, 2014	16,386.6	19,015.6	2,850.4	3,943.3	79.5	(16,844.7)	25,430.7
Equity in income (loss) of unconsolidated affiliates:							
Three months ended June 30, 2015	12.5	79.4	1.0	(3.7)	21.0	--	110.2
Three months ended June 30, 2014	6.1	42.2	0.9	(6.5)	7.6	--	50.3
Six months ended June 30, 2015	24.1	139.3	1.9	(7.1)	41.2	--	199.4
Six months ended June 30, 2014	7.5	84.9	1.8	(6.1)	18.7	--	106.8
Gross operating margin:							
Three months ended June 30, 2015	650.6	235.6	191.4	181.3	44.3	--	1,303.2
Three months ended June 30, 2014	680.9	184.0	203.0	161.7	33.6	--	1,263.2
Six months ended June 30, 2015	1,345.8	449.6	395.9	355.9	90.4	--	2,637.6
Six months ended June 30, 2014	1,460.9	343.7	423.4	292.1	72.9	--	2,593.0
Property, plant and equipment, net: (see Note 7)							
At June 30, 2015	11,919.2	2,484.3	8,741.0	3,057.9	--	3,581.4	29,783.8
At December 31, 2014	11,766.9	2,332.2	8,835.5	3,047.2	1,145.1	2,754.7	29,881.6
Investments in unconsolidated affiliates: (see Note 8)							
At June 30, 2015	683.5	1,818.3	31.1	74.3	--	--	2,607.2
At December 31, 2014	682.3	1,767.7	23.2	75.1	493.7	--	3,042.0
Intangible assets, net: (see Note 9)							
At June 30, 2015	246.6	1,334.9	953.1	198.9	--	--	2,733.5
At December 31, 2014	689.2	2,223.6	972.9	374.8	41.6	--	4,302.1
Goodwill: (see Note 9)							
At June 30, 2015	2,640.5	1,765.0	296.3	963.0	--	--	5,664.8
At December 31, 2014	2,207.9	914.3	296.3	792.2	82.0	--	4,292.7
Segment assets:							
At June 30, 2015	15,489.8	7,402.5	10,021.5	4,294.1	--	3,581.4	40,789.3
At December 31, 2014	15,346.3	7,237.8	10,127.9	4,289.3	1,762.4	2,754.7	41,518.4

At June 30, 2015, segment assets of our Offshore Pipelines & Services business segment were classified as held for sale; therefore, such amounts are not included in property, plant and equipment, investments in unconsolidated affiliates, intangible assets and goodwill on that date in the preceding table.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
NGL Pipelines & Services:				
Sales of NGLs and related products	$ 1,849.1	$ 3,630.6	$ 4,091.3	$ 8,426.4
Midstream services	417.0	390.6	851.1	774.3
Total	2,266.1	4,021.2	4,942.4	9,200.7
Crude Oil Pipelines & Services:				
Sales of crude oil	2,971.3	5,781.9	5,542.0	10,655.3
Midstream services	117.1	90.4	224.4	175.3
Total	3,088.4	5,872.3	5,766.4	10,830.6
Natural Gas Pipelines & Services:				
Sales of natural gas	429.9	787.0	906.2	1,740.2
Midstream services	254.8	254.0	512.4	505.4
Total	684.7	1,041.0	1,418.6	2,245.6
Petrochemical & Refined Products Services:				
Sales of petrochemicals and refined products	832.7	1,376.6	1,983.7	2,732.8
Midstream services	185.8	170.7	383.9	345.1
Total	1,018.5	1,547.3	2,367.6	3,077.9
Offshore Pipelines & Services:				
Sales of natural gas	--	--	--	0.2
Sales of crude oil	1.7	2.9	2.8	5.0
Midstream services	33.1	36.1	67.2	70.7
Total	34.8	39.0	70.0	75.9
Total consolidated revenues	$ 7,092.5	$ 12,520.8	$ 14,565.0	$ 25,430.7
Consolidated costs and expenses				
Operating costs and expenses:				
Cost of sales	$ 5,257.9	$ 10,705.3	$ 10,936.0	$ 21,758.0
Other operating costs and expenses (1)	632.5	624.5	1,192.3	1,231.7
Depreciation, amortization and accretion	385.6	312.4	730.9	613.8
Net losses (gains) attributable to asset sales and insurance recoveries	2.5	(6.8)	2.4	(96.4)
Non-cash asset impairment charges	79.0	3.7	112.3	12.5
General and administrative costs	44.9	47.7	94.2	100.9
Total consolidated costs and expenses	$ 6,402.4	$ 11,686.8	$ 13,068.1	$ 23,620.5

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

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

Note 13. Related Party Transactions

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
Revenues – related parties:				
Unconsolidated affiliates	$ 7.3	$ 17.3	$ 13.4	$ 52.8
Costs and expenses – related parties:				
EPCO and affiliates	$ 236.0	$ 239.5	$ 457.9	$ 475.2
Unconsolidated affiliates	59.2	46.0	98.4	102.6
Total	$ 295.2	$ 285.5	$ 556.3	$ 577.8

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

	June 30, 2015	December 31, 2014
Accounts receivable - related parties:		
Unconsolidated affiliates	$ 2.4	$ 2.8
Accounts payable - related parties:		
EPCO and affiliates	$ 91.7	$ 98.1
Unconsolidated affiliates	23.8	20.8
Total	$ 115.5	$ 118.9

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

Relationship with EPCO and Affiliates

We have an extensive and ongoing relationship with EPCO and its privately held affiliates (including Enterprise GP, our general partner), which are not a part of our consolidated group of companies. At June 30, 2015, 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	Percentage of Total Units Outstanding
689,490,269	34.4%

We and Enterprise GP are both separate legal entities apart from each other and apart from EPCO and its other affiliates, with assets and liabilities that are also separate from those of EPCO and its other affiliates. EPCO and its privately held affiliates depend on the cash distributions they receive from us and other investments to fund their other activities and to meet their debt obligations. During the six months ended June 30, 2015 and 2014, we paid EPCO and its privately held affiliates cash distributions totaling $466.7 million and $431.8 million, respectively.

In March 2015, a privately held affiliate of EPCO purchased 3,225,057 common units from us under our at-the-market program for $31.01 per unit. See Note 11 for information regarding our at-the-market program.

From time-to-time, EPCO and its privately held affiliates elect to reinvest a portion of the cash distributions they receive from us into the purchase of additional common units under our DRIP. See Note 11 for information regarding reinvestments made during 2015 and 2014.

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

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
Operating costs and expenses	$ 205.8	$ 208.9	$ 396.9	$ 412.6
General and administrative expenses	30.2	30.6	61.0	62.6
Total costs and expenses	$ 236.0	$ 239.5	$ 457.9	$ 475.2

Note 14. Earnings Per Unit

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
BASIC EARNINGS PER UNIT				
Net income attributable to limited partners	$ 551.0	$ 637.7	$ 1,187.1	$ 1,436.5
Undistributed earnings allocated and cash payments on phantom unit awards (1)	(2.2)	(1.2)	(4.4)	(2.7)
Net income available to common unitholders	$ 548.8	$ 636.5	$ 1,182.7	$ 1,433.8
Basic weighted-average number of common units outstanding	1,960.7	1,831.0	1,943.7	1,829.6
Basic earnings per unit	$ 0.28	$ 0.35	$ 0.61	$ 0.79
DILUTED EARNINGS PER UNIT				
Net income attributable to limited partners	$ 551.0	$ 637.7	$ 1,187.1	$ 1,436.5
Diluted weighted-average number of units outstanding:				
Distribution-bearing common units	1,960.7	1,831.0	1,943.7	1,829.6
Designated Units	35.4	45.1	35.4	45.1
Phantom units (1)	5.9	3.4	5.2	2.4
Incremental option units	0.1	0.9	0.2	1.1
Total	2,002.1	1,880.4	1,984.5	1,878.2
Diluted earnings per unit	$ 0.28	$ 0.34	$ 0.60	$ 0.76

(1) Each phantom unit award includes a DER, which entitles the recipient to receive cash payments equal to the product of the number of phantom unit awards and the cash distribution per unit paid to our common unitholders. Cash payments made in connection with DERs are nonforfeitable. As a result, the phantom units are considered participating securities for purposes of computing basic earnings per unit. Phantom unit awards were first issued in February 2014.

See Note 1 for information regarding a two-for-one common unit split completed in August 2014.

Note 15. Commitments and Contingencies

Litigation

As part of our normal business activities, we may be named as defendants in legal proceedings, including those arising from regulatory and environmental matters. Although we are insured against various risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to fully indemnify us against losses arising from future legal proceedings. We will vigorously defend the partnership in litigation matters.

Management has regular quarterly litigation reviews, including updates from legal counsel, to assess the possible need for accounting recognition and disclosure of these contingencies. We accrue an undiscounted liability for those contingencies where the loss is probable and the amount can be reasonably estimated. If a range of probable loss amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum amount in the range is accrued.

We do not record a contingent liability when the likelihood of loss is probable but the amount cannot be reasonably estimated or when the likelihood of loss is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is reasonably possible and the impact would be material to our consolidated financial statements, we disclose the nature of the contingency and, where feasible, an estimate of the possible loss or range of loss. Based on a consideration of all relevant known facts and circumstances, we do not believe that the ultimate outcome of any currently pending litigation directed against us will have a material impact on our consolidated financial statements either individually at the claim level or in the aggregate.

At June 30, 2015 and December 31, 2014, our accruals for litigation contingencies were $2.7 million and $2.4 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.

ETP Matter

In connection with a proposed pipeline project, we and Energy Transfer Partners, L.P. ("ETP") signed a non-binding letter of intent in April 2011 that disclaimed any partnership or joint venture related to such project absent executed definitive documents and board approvals of the respective companies. Definitive agreements were never executed and board approval was never obtained for the potential pipeline project. In August 2011, the proposed pipeline project was cancelled due to a lack of customer support.

In September 2011, ETP filed suit against us and a third party in connection with the cancelled project alleging, among other things, that we and ETP had formed a "partnership." The case was tried in the District Court of Dallas County, Texas, 298th Judicial District. While we firmly believe, and argued during our defense, that no agreement was ever executed forming a legal joint venture or partnership between the parties, the jury found that the actions of the two companies, nevertheless, constituted a legal partnership. As a result, the jury found that ETP was wrongfully excluded from a subsequent pipeline project involving a third party, and awarded ETP $319.4 million in actual damages on March 4, 2014. On July 29, 2014, the court entered judgment against us in an aggregate amount of $535.8 million, which includes (i) $319.4 million as the amount of actual damages awarded by the jury, (ii) an additional $150.0 million in disgorgement for the alleged benefit we received due to a breach of fiduciary duties by us against ETP and (iii) prejudgment interest in the amount of $66.4 million. The court also awarded post-judgment interest on such aggregate amount, to accrue at a rate of 5% per annum, compounded annually.

We do not believe that the verdict or the judgment entered against us is supported by the evidence or the law. On March 30, 2015, we filed our Brief of the Appellant in the Court of Appeals for the Fifth District of Dallas, Texas and intend to vigorously oppose the judgment through the appeals process. As of June 30, 2015, we have not recorded a provision for this matter as management believes payment of damages in this case is not probable.

FTC Matter

On February 23, 2015, we received a Civil Investigative Demand and a related Subpoena *Duces Tecum* from the FTC requesting specified information relating to the Oiltanking acquisition and Enterprise's operations. On April 13, 2015, we received a Civil Investigative Demand issued by the Attorney General of the State of Texas requesting copies of the same information and any correspondence with the FTC. We are in the process of complying with the requests and are cooperating with the investigations. Based on the limited information that we have at this time, we are unable to predict the outcome of the investigations.

Contractual Obligations

Scheduled Maturities of Debt

With the exception of (i) routine fluctuations in the balances of our revolving credit facility and commercial paper notes outstanding, (ii) the issuance of senior notes in May 2015 and (iii) the scheduled repayment of maturing senior debt obligations, our consolidated debt obligations at June 30, 2015 did not differ materially from those reported in our 2014 Form 10-K. See Note 10 for additional information regarding our consolidated debt obligations.

Operating Lease Obligations

Consolidated lease and rental expense was $25.2 million and $22.5 million during the second quarters of 2015 and 2014, respectively. For the six months ended June 30, 2015 and 2014, consolidated lease and rental expense was $47.6 million and $45.7 million, respectively. Our operating lease commitments at June 30, 2015 did not differ materially from those reported in our 2014 Form 10-K.

Purchase Obligations

Our consolidated purchase obligations at June 30, 2015 did not differ materially from those reported in our 2014 Form 10-K.

Liquidity Option Agreement

As described in Note 18 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of our 2014 Form 10-K, we entered into a put option agreement (the "Liquidity Option Agreement") with OTA and Marquard & Bahls ("M&B") in connection with the Oiltanking acquisition. Under the Liquidity Option Agreement, we granted M&B the option to sell to us 100% of the issued and outstanding capital stock of OTA at any time within a 90-day period commencing on February 1, 2020. At that time, OTA's only significant asset is expected to be the Enterprise common units it received in Step 1 of the Oiltanking acquisition, to the extent that such common units are not sold by M&B prior to the option exercise date pursuant to a related registration rights agreement.

In July 2015, we retrospectively adjusted our provisional fair value estimate for the Liquidity Option Agreement from $119.4 million to $212.2 million. The retrospective adjustment was applied in our December 31, 2014 Consolidated Balance Sheet as a $92.8 million increase in goodwill (see Note 9) and a corresponding increase in the Liquidity Option Agreement liability, which is a component of other long-term liabilities. The retrospective adjustment did not impact our historical results of operations, cash flows or other balance sheet amounts.

As described in our 2014 Form 10-K, the provisional estimate represents the present value at October 1, 2014 of estimated federal and state income tax payments that we would make on the taxable income of OTA, a corporation, over a stated period of time following exercise of the option. We expect that OTA's taxable income would, in turn, be based on an allocation of our partnership's taxable income to the common units held by OTA and reflect any tax mitigation strategies that we believe could be employed.

Our initial fair value estimate of $119.4 million was based on a variety of assumptions (each a Level 3 input), including a key assumption that a market participant would maintain the OTA corporate structure and not divest of its Enterprise common units for 30 years following exercise of the option in 2020. After further consideration, we revised this key assumption to reflect that a market participant might elect to dissolve the OTA corporate structure and sell the Enterprise common units at earlier dates. Accordingly, for purposes of our discounted cash flow model, we assigned an equal probability to the divesture of OTA and its assets over each of the 30 years in our forecast period. As a result, our provisional fair value estimate at October 1, 2014 increased by $92.8 million to $212.2 million, with a corresponding $92.8 million increase in goodwill which has been retrospectively adjusted as of December 31, 2014. This change is not considered material to our consolidated financial statements. None of the other key valuation assumptions we listed in our 2014 Form 10-K for the Liquidity Option Agreement have changed.

We believe the information gathered to date provides a reasonable basis for estimating the fair value of the Liquidity Option Agreement, but we are continuing to analyze certain 2014 federal income tax return calculations that are necessary to finalize our fair value estimate. We expect to finalize the initial fair value of the Liquidity Option Agreement by the end of the third quarter of 2015.

Results for the three and six months ended June 30, 2015 include $11.5 million of non-cash accretion expense associated with the change in fair value of the Liquidity Option Agreement from October 1, 2014 through June 30, 2015. The carrying value of the Liquidity Option Agreement, which is a component of "Other long-term liabilities" on our Unaudited Condensed Consolidated Balance Sheet, was $223.7 million at June 30, 2015 after recognition of this accretion amount.

Note 16. Supplemental Cash Flow Information

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

	For the Six Months Ended June 30,	
	2015	2014
Decrease (increase) in:		
Accounts receivable – trade	$ 460.9	$ 80.3
Accounts receivable – related parties	0.6	(43.4)
Inventories	(46.6)	(235.0)
Prepaid and other current assets	(50.5)	(64.3)
Other assets	3.6	21.5
Increase (decrease) in:		
Accounts payable – trade	3.4	(32.5)
Accounts payable – related parties	(3.4)	(36.5)
Accrued product payables	(559.4)	(0.6)
Accrued interest	14.5	15.3
Other current liabilities	(83.0)	90.0
Other liabilities	9.2	6.6
Net effect of changes in operating accounts	$ (250.7)	$ (198.6)

We incurred liabilities for construction in progress that had not been paid at June 30, 2015 and December 31, 2014 of $389.7 million and $372.8 million, respectively. Such amounts are not included under the caption “Capital expenditures” on the Unaudited Condensed Statements of Consolidated Cash Flows.

On certain of our capital projects, third parties are obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated with projects related to pipeline construction activities and production well tie-ins. These cash receipts are presented as “Contributions in aid of construction costs” within the investing activities section of our Unaudited Condensed Statements of Consolidated Cash Flows.

In February 2011, we experienced an NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility. As a final installment on the property damage claim we filed in connection with this incident, we received $95.0 million of nonrefundable cash insurance proceeds during the first quarter of 2014. Operating income for the six months ended June 30, 2014 includes $95.0 million of gains related to these proceeds. This gain was classified as a reduction in operating costs and expenses for the period.

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

	For the Six Months Ended June 30,	
	2015	2014
Insurance recoveries attributable to West Storage claims	$ --	$ 95.0
Other cash proceeds	5.9	18.2
Total	$ 5.9	$ 113.2

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

	For the Six Months Ended June 30,	
	2015	2014
Gains attributable to West Storage insurance recoveries	$ --	$ 95.0
Net gains (losses) attributable to other asset sales	(2.4)	1.4
Total	$ (2.4)	$ 96.4

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Note 17. Condensed Consolidating Financial Information

EPO conducts 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. As the parent company of EPO, Enterprise Products Partners L.P. guarantees substantially all of the debt obligations of EPO. 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. See Note 10 for additional information regarding our consolidated debt obligations.

EPO's consolidated subsidiaries have no significant restrictions on their ability to pay distributions or make loans to Enterprise Products Partners L.P.

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Balance Sheet
June 30, 2015

	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	$ 533.0	$ 75.4	$ (11.2)	$ 597.2	$ --	$ --	$ 597.2
Accounts receivable – trade, net	803.1	2,545.0	(2.0)	3,346.1	--	--	3,346.1
Accounts receivable – related parties	199.4	707.7	(888.8)	18.3	--	(15.9)	2.4
Inventories	791.8	208.4	(0.4)	999.8	--	--	999.8
Assets held for sale	--	1,710.7	--	1,710.7	--	--	1,710.7
Prepaid and other current assets	242.6	294.1	(15.2)	521.5	0.5	0.6	522.6
Total current assets	2,569.9	5,541.3	(917.6)	7,193.6	0.5	(15.3)	7,178.8
Property, plant and equipment, net	3,078.8	26,703.5	1.5	29,783.8	--	--	29,783.8
Investments in unconsolidated affiliates	39,056.2	4,006.9	(40,455.9)	2,607.2	20,364.5	(20,364.5)	2,607.2
Intangible assets, net	77.6	2,670.8	(14.9)	2,733.5	--	--	2,733.5
Goodwill	376.8	5,288.0	--	5,664.8	--	--	5,664.8
Other assets	149.4	42.6	(0.9)	191.1	0.2	--	191.3
Total assets	$ 45,308.7	$ 44,253.1	$ (41,387.8)	$ 48,174.0	$ 20,365.2	$ (20,379.8)	$ 48,159.4
LIABILITIES AND EQUITY							
Current liabilities:							
Current maturities of debt	$ 1,400.0	$ 0.1	$ --	$ 1,400.1	$ --	$ --	$ 1,400.1
Accounts payable – trade	295.3	506.1	(11.1)	790.3	--	--	790.3
Accounts payable – related parties	820.2	200.2	(904.9)	115.5	15.9	(15.9)	115.5
Accrued product payables	1,103.3	2,138.8	(2.0)	3,240.1	--	--	3,240.1
Accrued interest	349.9	0.1	--	350.0	--	--	350.0
Liabilities related to assets held for sale	--	116.4	--	116.4	--	--	116.4
Other current liabilities	110.8	358.1	(15.2)	453.7	--	--	453.7
Total current liabilities	4,079.5	3,319.8	(933.2)	6,466.1	15.9	(15.9)	6,466.1
Long-term debt	20,877.6	15.3	--	20,892.9	--	--	20,892.9
Deferred tax liabilities	3.2	47.8	(0.9)	50.1	--	4.9	55.0
Other long-term liabilities	16.1	142.9	(0.5)	158.5	223.7	--	382.2
Commitments and contingencies							
Equity:							
Partners' and other owners' equity	20,332.3	40,638.3	(40,630.1)	20,340.5	20,125.6	(20,340.5)	20,125.6
Noncontrolling interests held	--	26.8	176.9	203.7	--	(28.3)	175.4
Noncontrolling interests in assets held for sale	--	62.2	--	62.2	--	--	62.2
Total noncontrolling interests	--	89.0	176.9	265.9	--	(28.3)	237.6
Total equity	20,332.3	40,727.3	(40,453.2)	20,606.4	20,125.6	(20,368.8)	20,363.2
Total liabilities and equity	$ 45,308.7	$ 44,253.1	$ (41,387.8)	$ 48,174.0	$ 20,365.2	$ (20,379.8)	$ 48,159.4

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Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Balance Sheet
December 31, 2014

	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	$ 18.7	$ 70.4	$ (14.7)	$ 74.4	$ --	$ --	$ 74.4
Accounts receivable – trade, net	1,128.5	2,698.2	(3.7)	3,823.0	--	--	3,823.0
Accounts receivable – related parties	158.8	1,114.6	(1,266.6)	6.8	--	(4.0)	2.8
Inventories	831.8	182.8	(0.4)	1,014.2	--	--	1,014.2
Prepaid and other current assets	537.7	346.3	(308.5)	575.5	--	0.8	576.3
Total current assets	2,675.5	4,412.3	(1,593.9)	5,493.9	--	(3.2)	5,490.7
Property, plant and equipment, net	2,871.7	26,912.0	97.9	29,881.6	--	--	29,881.6
Investments in unconsolidated affiliates	36,937.5	3,556.4	(37,451.9)	3,042.0	18,280.0	(18,280.0)	3,042.0
Intangible assets, net	2,527.3	1,292.4	482.4	4,302.1	--	--	4,302.1
Goodwill	1,956.1	1,713.9	622.7	4,292.7	--	--	4,292.7
Other assets	139.3	45.8	(0.7)	184.4	--	--	184.4
Total assets	$ 47,107.4	$ 37,932.8	$ (37,843.5)	$ 47,196.7	$ 18,280.0	$ (18,283.2)	$ 47,193.5
LIABILITIES AND EQUITY							
Current liabilities:							
Current maturities of debt	$ 2,206.4	$ --	$ --	$ 2,206.4	$ --	$ --	$ 2,206.4
Accounts payable – trade	216.6	571.4	(14.8)	773.2	0.6	--	773.8
Accounts payable – related parties	1,226.5	173.3	(1,280.9)	118.9	4.0	(4.0)	118.9
Accrued product payables	1,570.0	2,287.9	(4.6)	3,853.3	--	--	3,853.3
Accrued interest	335.4	0.7	(0.6)	335.5	--	--	335.5
Other current liabilities	130.8	763.7	(308.7)	585.8	--	--	585.8
Total current liabilities	5,685.7	3,797.0	(1,609.6)	7,873.1	4.6	(4.0)	7,873.7
Long-term debt	19,142.5	14.9	--	19,157.4	--	--	19,157.4
Deferred tax liabilities	4.9	58.5	(0.9)	62.5	--	4.1	66.6
Other long-term liabilities	10.9	180.8	(0.3)	191.4	212.2	--	403.6
Commitments and contingencies							
Equity:							
Partners' and other owners' equity	22,263.4	33,813.4	(37,820.6)	18,256.2	18,063.2	(18,256.2)	18,063.2
Noncontrolling interests	--	68.2	1,587.9	1,656.1	--	(27.1)	1,629.0
Total equity	22,263.4	33,881.6	(36,232.7)	19,912.3	18,063.2	(18,283.3)	19,692.2
Total liabilities and equity	$ 47,107.4	$ 37,932.8	$ (37,843.5)	$ 47,196.7	$ 18,280.0	$ (18,283.2)	$ 47,193.5

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

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
For the Three Months Ended June 30, 2015

	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	$ 5,036.0	$ 5,394.7	$ (3,338.2)	$ 7,092.5	$ --	$ --	$ 7,092.5
Costs and expenses:							
Operating costs and expenses	4,865.4	4,830.4	(3,338.3)	6,357.5	--	--	6,357.5
General and administrative costs	9.4	34.9	--	44.3	0.6	--	44.9
Total costs and expenses	4,874.8	4,865.3	(3,338.3)	6,401.8	0.6	--	6,402.4
Equity in income of unconsolidated affiliates	643.2	106.4	(639.4)	110.2	563.1	(563.1)	110.2
Operating income	804.4	635.8	(639.3)	800.9	562.5	(563.1)	800.3
Other income (expense):							
Interest expense	(240.1)	(0.3)	--	(240.4)	--	--	(240.4)
Other, net	0.3	--	--	0.3	(11.5)	--	(11.2)
Total other expense, net	(239.8)	(0.3)	--	(240.1)	(11.5)	--	(251.6)
Income before income taxes	564.6	635.5	(639.3)	560.8	551.0	(563.1)	548.7
Benefit from (provision for) income taxes	(2.4)	10.7	--	8.3	--	(0.4)	7.9
Net income	562.2	646.2	(639.3)	569.1	551.0	(563.5)	556.6
Net loss (income) attributable to noncontrolling interests	--	0.5	(7.2)	(6.7)	--	1.1	(5.6)
Net income attributable to entity	$ 562.2	$ 646.7	$ (646.5)	$ 562.4	$ 551.0	$ (562.4)	$ 551.0

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
For the Three Months Ended June 30, 2014

	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	$ 7,577.7	$ 9,151.1	$ (4,208.0)	$ 12,520.8	$ --	$ --	$ 12,520.8
Costs and expenses:							
Operating costs and expenses	7,397.9	8,449.6	(4,208.4)	11,639.1	--	--	11,639.1
General and administrative costs	7.6	39.9	--	47.5	0.2	--	47.7
Total costs and expenses	7,405.5	8,489.5	(4,208.4)	11,686.6	0.2	--	11,686.8
Equity in income of unconsolidated affiliates	700.2	75.9	(725.8)	50.3	637.9	(637.9)	50.3
Operating income	872.4	737.5	(725.4)	884.5	637.7	(637.9)	884.3
Other income (expense):							
Interest expense	(228.6)	(0.3)	--	(228.9)	--	--	(228.9)
Other, net	0.3	0.8	--	1.1	--	--	1.1
Total other expense, net	(228.3)	0.5	--	(227.8)	--	--	(227.8)
Income before income taxes	644.1	738.0	(725.4)	656.7	637.7	(637.9)	656.5
Provision for income taxes	(7.3)	(2.7)	0.2	(9.8)	--	(0.2)	(10.0)
Net income	636.8	735.3	(725.2)	646.9	637.7	(638.1)	646.5
Net income attributable to noncontrolling interests	--	0.1	(10.2)	(10.1)	--	1.3	(8.8)
Net income attributable to entity	$ 636.8	$ 735.4	$ (735.4)	$ 636.8	$ 637.7	$ (636.8)	$ 637.7

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

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
For the Six Months Ended June 30, 2015

	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	$ 10,615.8	$ 10,219.9	$ (6,270.7)	$ 14,565.0	$ --	$ --	$ 14,565.0
Costs and expenses:							
Operating costs and expenses	10,189.5	9,055.3	(6,270.9)	12,973.9	--	--	12,973.9
General and administrative costs	17.8	75.6	--	93.4	0.8	--	94.2
Total costs and expenses	10,207.3	9,130.9	(6,270.9)	13,067.3	0.8	--	13,068.1
Equity in income of unconsolidated affiliates	1,270.9	198.0	(1,269.5)	199.4	1,199.4	(1,199.4)	199.4
Operating income	1,679.4	1,287.0	(1,269.3)	1,697.1	1,198.6	(1,199.4)	1,696.3
Other income (expense):							
Interest expense	(478.4)	(3.1)	2.0	(479.5)	--	--	(479.5)
Other, net	2.3	0.5	(2.0)	0.8	(11.5)	--	(10.7)
Total other expense, net	(476.1)	(2.6)	--	(478.7)	(11.5)	--	(490.2)
Income before income taxes	1,203.3	1,284.4	(1,269.3)	1,218.4	1,187.1	(1,199.4)	1,206.1
Benefit from (provision for) income taxes	(5.6)	7.6	--	2.0	--	(0.9)	1.1
Net income	1,197.7	1,292.0	(1,269.3)	1,220.4	1,187.1	(1,200.3)	1,207.2
Net loss (income) attributable to noncontrolling interests	--	0.8	(23.2)	(22.4)	--	2.3	(20.1)
Net income attributable to entity	$ 1,197.7	$ 1,292.8	$ (1,292.5)	$ 1,198.0	$ 1,187.1	$ (1,198.0)	$ 1,187.1

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
For the Six Months Ended June 30, 2014

	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	$ 17,068.6	$ 17,261.7	$ (8,899.6)	$ 25,430.7	$ --	$ --	$ 25,430.7
Costs and expenses:							
Operating costs and expenses	16,565.7	15,854.1	(8,900.2)	23,519.6	--	--	23,519.6
General and administrative costs	14.9	85.6	--	100.5	0.4	--	100.9
Total costs and expenses	16,580.6	15,939.7	(8,900.2)	23,620.1	0.4	--	23,620.5
Equity in income of unconsolidated affiliates	1,407.0	161.7	(1,461.9)	106.8	1,436.9	(1,436.9)	106.8
Operating income	1,895.0	1,483.7	(1,461.3)	1,917.4	1,436.5	(1,436.9)	1,917.0
Other income (expense):							
Interest expense	(449.4)	(0.4)	--	(449.8)	--	--	(449.8)
Other, net	0.5	0.3	--	0.8	--	--	0.8
Total other expense, net	(448.9)	(0.1)	--	(449.0)	--	--	(449.0)
Income before income taxes	1,446.1	1,483.6	(1,461.3)	1,468.4	1,436.5	(1,436.9)	1,468.0
Provision for income taxes	(11.5)	(3.0)	0.2	(14.3)	--	(0.5)	(14.8)
Net income	1,434.6	1,480.6	(1,461.1)	1,454.1	1,436.5	(1,437.4)	1,453.2
Net income attributable to noncontrolling interests	--	0.1	(19.3)	(19.2)	--	2.5	(16.7)
Net income attributable to entity	$ 1,434.6	$ 1,480.7	$ (1,480.4)	$ 1,434.9	$ 1,436.5	$ (1,434.9)	$ 1,436.5

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Comprehensive Income
For the Three Months Ended June 30, 2015

	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	$ 572.0	$ 621.0	$ (639.3)	$ 553.7	$ 535.6	$ (548.1)	$ 541.2
Comprehensive loss (income) attributable to noncontrolling interests	--	0.5	(7.2)	(6.7)	--	1.1	(5.6)
Comprehensive income attributable to entity	$ 572.0	$ 621.5	$ (646.5)	$ 547.0	$ 535.6	$ (547.0)	$ 535.6

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Comprehensive Income
For the Three Months Ended June 30, 2014

	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	$ 644.9	$ 717.2	$ (725.1)	$ 637.0	$ 627.8	$ (628.2)	$ 636.6
Comprehensive income attributable to noncontrolling interests	--	0.1	(10.2)	(10.1)	--	1.3	(8.8)
Comprehensive income attributable to entity	$ 644.9	$ 717.3	$ (735.3)	$ 626.9	$ 627.8	$ (626.9)	$ 627.8

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

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Comprehensive Income
For the Six Months Ended June 30, 2015

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Comprehensive income	$ 1,193.9	$ 1,258.8	$ (1,269.3)	$ 1,183.4	$ 1,150.1	$ (1,163.3)	$ 1,170.2
Comprehensive loss (income) attributable to noncontrolling interests	--	0.8	(23.2)	(22.4)	--	2.3	(20.1)
Comprehensive income attributable to entity	$ 1,193.9	$ 1,259.6	$ (1,292.5)	$ 1,161.0	$ 1,150.1	$ (1,161.0)	$ 1,150.1

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Comprehensive Income
For the Six Months Ended June 30, 2014

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Comprehensive income	$ 1,452.9	$ 1,467.0	$ (1,461.0)	$ 1,458.9	$ 1,441.3	$ (1,442.2)	$ 1,458.0
Comprehensive income attributable to noncontrolling interests	--	0.1	(19.3)	(19.2)	--	2.5	(16.7)
Comprehensive income attributable to entity	$ 1,452.9	$ 1,467.1	$ (1,480.3)	$ 1,439.7	$ 1,441.3	$ (1,439.7)	$ 1,441.3

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

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Cash Flows
For the Six Months Ended June 30, 2015

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Operating activities:							
Net income	$ 1,197.7	$ 1,292.0	$ (1,269.3)	$ 1,220.4	$ 1,187.1	$ (1,200.3)	$ 1,207.2
Reconciliation of net income to net cash flows provided by operating activities:							
Depreciation, amortization and accretion	66.2	708.9	(0.2)	774.9	--	--	774.9
Equity in income of unconsolidated affiliates	(1,270.9)	(198.0)	1,269.5	(199.4)	(1,199.4)	1,199.4	(199.4)
Distributions received from unconsolidated affiliates	1,231.3	203.4	(1,169.2)	265.5	1,493.2	(1,493.2)	265.5
Net effect of changes in operating accounts and other operating activities	(104.8)	(53.1)	3.5	(154.4)	6.9	0.9	(146.6)
Net cash flows provided by operating activities	1,119.5	1,953.2	(1,165.7)	1,907.0	1,487.8	(1,493.2)	1,901.6
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(436.3)	(1,193.9)	--	(1,630.2)	--	--	(1,630.2)
Proceeds from asset sales and insurance recoveries	2.5	3.4	--	5.9	--	--	5.9
Other investing activities	(579.0)	(49.9)	463.9	(165.0)	(940.4)	940.4	(165.0)
Cash used in investing activities	(1,012.8)	(1,240.4)	463.9	(1,789.3)	(940.4)	940.4	(1,789.3)
Financing activities:							
Borrowings under debt agreements	13,838.3	--	--	13,838.3	--	--	13,838.3
Repayments of debt	(12,905.0)	--	--	(12,905.0)	--	--	(12,905.0)
Cash distributions paid to partners	(1,493.2)	(1,193.2)	1,193.2	(1,493.2)	(1,437.3)	1,493.2	(1,437.3)
Cash payments made in connection with DERs	--	--	--	--	(3.4)	--	(3.4)
Cash distributions paid to noncontrolling interests	--	(0.8)	(24.0)	(24.8)	--	--	(24.8)
Cash contributions from noncontrolling interests	--	22.4	(0.4)	22.0	--	--	22.0
Net cash proceeds from issuance of common units	--	--	--	--	944.1	--	944.1
Cash contributions from owners	940.4	463.5	(463.5)	940.4	--	(940.4)	--
Other financing activities	(18.7)	--	--	(18.7)	(50.8)	--	(69.5)
Cash used in financing activities	361.8	(708.1)	705.3	359.0	(547.4)	552.8	364.4
Net change in cash and cash equivalents	468.5	4.7	3.5	476.7	--	--	476.7
Cash and cash equivalents, January 1	18.7	70.4	(14.7)	74.4	--	--	74.4
Cash and cash equivalents, June 30	$ 487.2	$ 75.1	$ (11.2)	$ 551.1	$ --	$ --	$ 551.1

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

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Cash Flows
For the Six Months Ended June 30, 2014

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	**Other Subsidiaries (Non-guarantor)**	**EPO and Subsidiaries Eliminations and Adjustments**	**Consolidated EPO and Subsidiaries**	**Enterprise Products Partners L.P. (Guarantor)**	**Eliminations and Adjustments**	**Consolidated Total**
Operating activities:							
Net income	$ 1,434.6	$ 1,480.6	$ (1,461.1)	$ 1,454.1	$ 1,436.5	$ (1,437.4)	$ 1,453.2
Reconciliation of net income to net cash flows provided by operating activities:							
Depreciation, amortization and accretion	74.9	576.3	(0.2)	651.0	--	--	651.0
Equity in income of unconsolidated affiliates	(1,407.0)	(161.7)	1,461.9	(106.8)	(1,436.9)	1,436.9	(106.8)
Distributions received from unconsolidated affiliates	1,829.3	137.9	(1,810.1)	157.1	1,346.5	(1,346.5)	157.1
Net effect of changes in operating accounts and other operating activities	(334.9)	56.5	0.6	(277.8)	(5.3)	0.5	(282.6)
Net cash flows provided by operating activities	1,596.9	2,089.6	(1,808.9)	1,877.6	1,340.8	(1,346.5)	1,871.9
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(166.8)	(1,005.7)	--	(1,172.5)	--	--	(1,172.5)
Proceeds from asset sales and insurance recoveries	3.8	109.4	--	113.2	--	--	113.2
Other investing activities	(1,155.2)	(443.7)	1,103.3	(495.6)	(221.3)	221.3	(495.6)
Cash used in investing activities	(1,318.2)	(1,340.0)	1,103.3	(1,554.9)	(221.3)	221.3	(1,554.9)
Financing activities:							
Borrowings under debt agreements	4,182.8	--	--	4,182.8	--	--	4,182.8
Repayments of debt	(3,161.3)	--	--	(3,161.3)	--	--	(3,161.3)
Cash distributions paid to partners	(1,346.5)	(1,829.8)	1,829.8	(1,346.5)	(1,288.4)	1,346.5	(1,288.4)
Cash payments made in connection with DERs	--	--	--	--	(1.2)	--	(1.2)
Cash distributions paid to noncontrolling interests	--	--	(19.7)	(19.7)	--	--	(19.7)
Cash contributions from noncontrolling interests	--	--	4.0	4.0	--	--	4.0
Net cash proceeds from issuance of common units	--	--	--	--	223.3	--	223.3
Cash contributions from owners	221.3	1,107.3	(1,107.3)	221.3	--	(221.3)	--
Other financing activities	(18.2)	--	--	(18.2)	(53.2)	--	(71.4)
Cash provided by (used in) financing activities	(121.9)	(722.5)	706.8	(137.6)	(1,119.5)	1,125.2	(131.9)
Net change in cash and cash equivalents	156.8	27.1	1.2	185.1	--	--	185.1
Cash and cash equivalents, January 1	28.4	49.5	(21.0)	56.9	--	--	56.9
Cash and cash equivalents, June 30	$ 185.2	$ 76.6	$ (19.8)	$ 242.0	$ --	$ --	$ 242.0

Note 18. Subsequent Event

Acquisition of Eagle Ford Midstream Assets

In June 2015, we announced the execution of definitive agreements to purchase all of the member interests in EFS Midstream LLC ("EFS Midstream") from affiliates of Pioneer Natural Resources Company ("Pioneer") and Reliance Industries Limited ("Reliance") for $2.15 billion. The purchase price will be paid in two installments, the first installment of $1.15 billion was paid at closing on July 8, 2015 and the final installment of $1.0 billion will be paid no later than the first anniversary of the closing date. The effective date of the acquisition was July 1, 2015. We funded the cash consideration for the first installment using proceeds from the issuance of short-term notes under our commercial paper program and cash on hand.

EFS Midstream provides natural gas gathering, treating, compression and condensate gathering and processing services in the Eagle Ford Shale. The EFS Midstream system includes approximately 460 miles of natural gas and condensate gathering pipelines, ten central gathering plants, 780 MMcf/d of natural gas treating capacity and 119 MBPD of condensate stabilization capacity. Under the terms of the agreements, the Pioneer and Reliance joint development has dedicated its Eagle Ford Shale acreage to us under a 20-year, fixed-fee gathering agreement that includes a minimum volume requirement for the first seven years. Pioneer and Reliance have also dedicated their Eagle Ford Shale acreage under related 20-year fee-based agreements with us for natural gas processing, NGL transportation and fractionation, and for natural gas, processed condensate and crude oil transportation services.

Due to the recent nature of this transaction, we have not completed the allocation of the purchase price.

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

For the Three and Six Months Ended June 30, 2015 and 2014.

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, 2014, as filed on March 2, 2015 (the "2014 Form 10-K"). Our financial statements have been prepared in accordance with generally accepted accounting principles ("GAAP") in the United States ("U.S.").

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 privately held Texas limited liability company.

The membership interests of Dan Duncan LLC are owned 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; and (iii) Richard H. Bachmann. 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 privately held Texas corporation, and its privately held affiliates. A majority of the outstanding voting capital stock of EPCO is owned by a voting trust, the current trustees ("EPCO Trustees") of which are: (i) Ms. Williams, who serves as Chairman of EPCO; (ii) Dr. Cunningham, who serves as a Vice Chairman of EPCO; and (iii) Mr. Bachmann, who serves as the President and Chief Executive Officer ("CEO") of EPCO. Each of the EPCO Trustees is also a director of EPCO.

In addition to owning our general partner, EPCO and its privately held affiliates owned approximately 34.4% of our limited partner interests at June 30, 2015.

References to "Oiltanking" and "Oiltanking GP" mean Oiltanking Partners, L.P. and OTLP GP, LLC, the general partner of Oiltanking, respectively. In October 2014, we acquired approximately 65.9% of the limited partner interests of Oiltanking, all of the member interests of Oiltanking GP and the incentive distribution rights ("IDRs") held by Oiltanking GP from Oiltanking Holding Americas, Inc. ("OTA") as the first step of a two-step acquisition of Oiltanking. In February 2015, we completed the second step of this acquisition. See "Significant Recent Developments" within this Part I, Item 2 for information regarding the completion of this acquisition.

References to "Offshore Gulf of Mexico Business" or "Offshore Business" refer to the operations we sold to Genesis Energy, L.P. ("Genesis") in July 2015. See "Significant Recent Developments" for additional information regarding this sale.

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*

As used in this quarterly report, the phrase "quarter-to-quarter" means the second quarter of 2015 compared to the second quarter of 2014. Likewise, the phrase "period-to-period" means the six months ended June 30, 2015 compared to the six months ended June 30, 2014.

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 2014 Form 10-K and within Part II, Item 1A of this quarterly report. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements. The forward-looking statements in this quarterly report speak only as of the filing date hereof. Except as required by federal and state securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason.

Overview of Business

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

Our integrated midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the U.S., Canada and Gulf of Mexico with domestic consumers and international markets. Our midstream energy operations currently include: natural gas gathering, treating, processing, transportation and storage; NGL transportation, fractionation, storage, and import and export terminals (including liquefied petroleum gas or "LPG"); crude oil gathering, transportation, storage and terminals; petrochemical and refined products transportation, storage and terminals, and related 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 49,000 miles of onshore pipelines; 225 MMBbls of storage capacity for NGLs, petrochemicals, refined products and crude oil; and 14 Bcf of natural gas storage capacity.

On February 13, 2015, we completed our acquisition of Oiltanking. See "Significant Recent Developments" within this Part I, Item 2 for information regarding this acquisition.

Our historical operations are reported under five business segments: (i) NGL Pipelines & Services, (ii) Crude Oil Pipelines & Services, (iii) Natural Gas Pipelines & Services, (iv) Petrochemical & Refined Products Services and (v) Offshore Pipelines & Services.

On July 24, 2015, we completed the sale of our Offshore Business to Genesis. The assets, liabilities and related noncontrolling interest attributable to this business were classified as held for sale at June 30, 2015. As a result of this sale, we renamed our Onshore Crude Oil Pipelines & Services business segment "Crude Oil Pipelines & Services." In addition, we renamed our Onshore Natural Gas Pipelines & Services business segment "Natural Gas Pipelines & Services." The operations reported within these two onshore segments did not change due to these name changes. We will continue to report the historical results of the Offshore Pipelines & Services segment through the closing date of the sales transaction. For additional information regarding our business segments, see Note 12 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

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 ("ASA") or by other service providers.

Significant Recent Developments

The following information highlights selected commercial and operational developments since January 1, 2015. For information regarding recent offerings of our equity and debt securities, see "Liquidity and Capital Resources" within this Part I, Item 2.

Sale of Offshore Gulf of Mexico Business
On July 16, 2015, we announced the execution of a Purchase and Sale Agreement with Genesis whereby they agreed to acquire our Offshore Business, which primarily consists of our Offshore Pipelines & Services business segment, for approximately $1.53 billion in cash. Our Offshore Business served drilling and development regions, including deepwater production fields, in the northern Gulf of Mexico offshore Texas, Louisiana, Mississippi and Alabama. As of December 31, 2014, our Offshore Business included approximately 2,350 miles of offshore natural gas and crude oil pipelines and six offshore hub platforms. The transaction closed on July 24, 2015. We maintained ownership of this business until the closing date.

We viewed our Offshore Business as an extension of our midstream energy services network. As such, the sale of these assets does not represent a strategic shift in our consolidated operations that would have a major effect on our operations and financial results. The sale of this non-strategic business allows us to redeploy capital to other business opportunities that we believe will generate a higher return for us in the future (e.g., our recent acquisition of EFS Midstream LLC (see below)). Also, proceeds from the closing of this sale will reduce our need to issue additional equity to support our ongoing capital spending program.

For additional information regarding this sale, see Note 6 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Expansion of Propylene Pipeline System
In July 2015, we announced a series of projects to convert and expand segments of our petrochemicals pipeline network designed to increase throughput capacity for polymer grade propylene ("PGP") and enhance system flexibility and reliability.

§ *North Dean pipeline conversion and expansion* – The 149-mile pipeline will be converted from refinery grade propylene ("RGP") service to PGP service. The conversion is scheduled for completion in January 2017. Originating at our Mont Belvieu, Texas complex, the converted pipeline will serve petrochemical facilities as far south as Seadrift, Texas in Calhoun County. Construction of a 33-mile lateral pipeline, new metering stations and additional pumping capacity will accommodate the additional volumes and increase total PGP delivery capacity to more than 150 MBPD.

§ *Lou-Tex propylene pipeline conversion* – The 263-mile, bi-directional pipeline, which currently transports chemical grade propylene ("CGP") between Sorrento, Louisiana and Mont Belvieu, Texas will be converted to PGP service. The conversion is scheduled for completion in 2020.

§ *RGP pipeline and rail terminal expansion* – Construction of a new 65-mile, 10-inch diameter pipeline, which will transport RGP between Sorrento and Breaux Bridge, Louisiana, is scheduled for completion in early 2017. Rail receipt facilities at Mont Belvieu are also being expanded to give us the capability to unload up to 100 RGP rail cars per day.

Our PGP infrastructure at Mont Belvieu currently consists of six propane/propylene fractionators. Following completion of the new propane dehydrogenation ("PDH") plant, which is scheduled for September 2016, we will have the capability to produce 8 billion pounds of PGP annually at our Mont Belvieu complex. In addition, a portion of our salt dome storage capacity in Mont Belvieu is dedicated to PGP service.

Acquisition of Eagle Ford Midstream Assets
In June 2015, we announced the execution of definitive agreements to purchase all of the member interests in EFS Midstream LLC ("EFS Midstream") from affiliates of Pioneer Natural Resources Company ("Pioneer") and Reliance Industries Limited ("Reliance") for $2.15 billion. The purchase price will be paid in two installments, the first installment of $1.15 billion was paid at closing on July 8, 2015 and the final installment of $1.0 billion will be paid no later than the first anniversary of the closing date. The effective date of the acquisition was July 1, 2015.

EFS Midstream provides natural gas gathering, treating, compression and condensate gathering and processing services in the Eagle Ford Shale. The EFS Midstream system includes approximately 460 miles of natural gas and condensate gathering pipelines, ten central gathering plants, 780 MMcf/d of natural gas treating capacity and 119 MBPD of condensate stabilization capacity. Under the terms of the agreements, the Pioneer and Reliance joint development has dedicated its Eagle Ford Shale acreage to us under a 20-year, fixed-fee gathering agreement that includes a minimum volume requirement for the first seven years. Pioneer and Reliance have also dedicated their Eagle Ford Shale acreage under related 20-year fee-based agreements with us for natural gas processing, NGL transportation and fractionation, and for natural gas, processed condensate and crude oil transportation services.

Plans to Construct New Crude Oil and Condensate Pipeline from Midland to Houston, Texas
In April 2015, we announced the execution of long-term agreements that support development of a new 24-inch diameter pipeline (the "Midland-to-Houston" pipeline) that would transport increasing volumes of crude oil and condensate from the Permian Basin to markets in Southeast Texas. The new pipeline will originate at our Midland, Texas crude oil terminal and extend 416 miles to our Sealy storage facility, which is located west of Houston, Texas. Volumes arriving at Sealy would then be transported to our Enterprise Crude Houston ("ECHO") terminal in southeast Houston using our Rancho II pipeline, which is currently under construction and expected to be complete in August 2015. Through ECHO, shippers will have direct access to every refinery in Houston, Texas City, Beaumont and Port Arthur, as well as our dock facilities. The Midland-to-Houston pipeline is expected to have a transportation capacity of up to 450 MBPD and commence operations in the second quarter of 2017.

Plans to Construct Natural Gas Processing Facility in Delaware Basin
In April 2015, we formed a 50/50 joint venture with an affiliate of Occidental Petroleum Corporation to develop a new 150 MMcf/d cryogenic natural gas processing facility that will accommodate growing production of NGL-rich natural gas from the Delaware Basin. The facility will be supported by long-term, firm contracts and is expected to begin operations in mid-2016. We will serve as construction manager for the project and operator once the new facility commences operations. The new facility is located in Reeves County, Texas.

Increase in NGL Loading Capacity at our Houston Ship Channel LPG Export Terminal
In September 2013, we announced an expansion project at our Houston Ship Channel LPG export terminal that would increase our ability to load cargoes from 7.5 MMBbls per month to approximately 9.0 MMBbls per month. This project was completed in April 2015.

In January 2014, we announced a further expansion of this export terminal that is expected to increase our loading capability from approximately 9.0 MMBbls per month to in excess of 16.0 MMBbls per month by the end of 2015. We expect our maximum loading capacity at this terminal to be approximately 27,000 barrels per hour once this expansion project is completed. Our expansion projects at this terminal are supported by long-term LPG sales agreements with exporters.

Formation of Panola Pipeline Joint Venture
In February 2015, we formed a joint venture involving our Panola NGL Pipeline with affiliates of Anadarko Petroleum Corporation ("Anadarko"), DCP Midstream Partners, LP ("DCP") and MarkWest Energy Partners, L.P. ("MarkWest"). We will continue to serve as operator of the Panola Pipeline and own 55% of the member interests in the joint venture. Affiliates of Anadarko, DCP and MarkWest will own the remaining 45% member interests, with each holding a 15% interest.

The Panola Pipeline transports mixed NGLs from points near Carthage, Texas to Mont Belvieu, Texas and supports the Haynesville and Cotton Valley oil and gas production areas. In January 2015, we announced an expansion project involving the Panola Pipeline consisting of the installation of 60 miles of new pipeline, as well as pumps and other related equipment designed to increase the system's throughput capacity by 50 MBPD to approximately 100 MBPD. The incremental capacity is expected to be available in the first quarter of 2016.

Completion of Oiltanking Acquisition
In October 2014, we completed the first step ("Step 1") of a two-step acquisition of Oiltanking by paying approximately $4.41 billion to OTA for Oiltanking GP, the related IDRs and approximately 65.9% of the limited partner interests of Oiltanking. As a second step ("Step 2") of the Oiltanking acquisition (separately negotiated by the conflicts committee of Oiltanking GP on behalf of Oiltanking), we entered into an Agreement and Plan of Merger (the "merger agreement") with Oiltanking in November 2014 that provided for the following:

§ the merger of a wholly owned subsidiary of Enterprise with and into Oiltanking, with Oiltanking surviving the merger as a wholly owned subsidiary of Enterprise; and

§ all outstanding common units of Oiltanking at the effective time of the merger held by Oiltanking's public unitholders (which consisted of Oiltanking unitholders other than Enterprise and its subsidiaries) to be cancelled and converted into Enterprise common units based on an exchange ratio of 1.30 Enterprise common units for each Oiltanking common unit.

In accordance with the merger agreement and Oiltanking's partnership agreement, the merger was submitted to a vote of Oiltanking's common unitholders, with the required majority of unitholders (including our ownership interests) voting to approve the merger on February 13, 2015. Upon approval of the merger, a total of 36,827,517 of our common units were issued to Oiltanking's former public unitholders. With the completion of Step 2, total consideration paid by Enterprise for Oiltanking was approximately $5.9 billion.

On February 23, 2015, we received a Civil Investigative Demand and a related Subpoena *Duces Tecum* from the Federal Trade Commission ("FTC") requesting specified information relating to the Oiltanking acquisition and Enterprise's operations. On April 13, 2015, we received a Civil Investigative Demand issued by the Attorney General of the State of Texas requesting copies of the same information and any correspondence with the FTC. We are in the process of complying with the requests and are cooperating with the investigations. Based on the limited information that we have at this time, we are unable to predict the outcome of the investigations.

For information regarding changes in our goodwill and equity balances as a result of completing the Oiltanking acquisition, see Notes 9 and 11, respectively, of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Results of Operations

Summarized Consolidated Income Statement Data

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
Revenues	$ 7,092.5	$ 12,520.8	$ 14,565.0	$ 25,430.7
Costs and expenses:				
Operating costs and expenses:				
Cost of sales	5,257.9	10,705.3	10,936.0	21,758.0
Other operating costs and expenses	632.5	624.5	1,192.3	1,231.7
Depreciation, amortization and accretion expenses	385.6	312.4	730.9	613.8
Net losses (gains) attributable to asset sales and insurance recoveries	2.5	(6.8)	2.4	(96.4)
Non-cash asset impairment charges	79.0	3.7	112.3	12.5
Total operating costs and expenses	6,357.5	11,639.1	12,973.9	23,519.6
General and administrative costs	44.9	47.7	94.2	100.9
Total costs and expenses	6,402.4	11,686.8	13,068.1	23,620.5
Equity in income of unconsolidated affiliates	110.2	50.3	199.4	106.8
Operating income	800.3	884.3	1,696.3	1,917.0
Interest expense	(240.4)	(228.9)	(479.5)	(449.8)
Change in fair value of Liquidity Option Agreement	(11.5)	--	(11.5)	--
Other, net	0.3	1.1	0.8	0.8
Benefit from (provision for) income taxes	7.9	(10.0)	1.1	(14.8)
Net income	556.6	646.5	1,207.2	1,453.2
Net income attributable to noncontrolling interests	(5.6)	(8.8)	(20.1)	(16.7)
Net income attributable to limited partners	$ 551.0	$ 637.7	$ 1,187.1	$ 1,436.5

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
NGL Pipelines & Services:				
Sales of NGLs and related products	$ 1,849.1	$ 3,630.6	$ 4,091.3	$ 8,426.4
Midstream services	417.0	390.6	851.1	774.3
Total	2,266.1	4,021.2	4,942.4	9,200.7
Crude Oil Pipelines & Services:				
Sales of crude oil	2,971.3	5,781.9	5,542.0	10,655.3
Midstream services	117.1	90.4	224.4	175.3
Total	3,088.4	5,872.3	5,766.4	10,830.6
Natural Gas Pipelines & Services:				
Sales of natural gas	429.9	787.0	906.2	1,740.2
Midstream services	254.8	254.0	512.4	505.4
Total	684.7	1,041.0	1,418.6	2,245.6
Petrochemical & Refined Products Services:				
Sales of petrochemicals and refined products	832.7	1,376.6	1,983.7	2,732.8
Midstream services	185.8	170.7	383.9	345.1
Total	1,018.5	1,547.3	2,367.6	3,077.9
Offshore Pipelines & Services:				
Sales of natural gas	--	--	--	0.2
Sales of crude oil	1.7	2.9	2.8	5.0
Midstream services	33.1	36.1	67.2	70.7
Total	34.8	39.0	70.0	75.9
Total consolidated revenues	$ 7,092.5	$ 12,520.8	$ 14,565.0	$ 25,430.7

Selected Energy Commodity Price Data

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

	Natural Gas, $/MMBtu (1)	Ethane, $/gallon (2)	Propane, $/gallon (2)	Normal Butane, $/gallon (2)	Isobutane, $/gallon (2)	Natural Gasoline, $/gallon (2)	Polymer Grade Propylene, $/pound (3)	Refinery Grade Propylene, $/pound (3)	WTI Crude Oil, $/barrel (4)	LLS Crude Oil, $/barrel (4)
2014 by quarter:										
1st Quarter	$ 4.95	$ 0.34	$ 1.30	$ 1.39	$ 1.42	$ 2.12	$ 0.73	$ 0.61	$ 98.68	$ 104.43
2nd Quarter	$ 4.68	$ 0.29	$ 1.06	$ 1.25	$ 1.30	$ 2.21	$ 0.70	$ 0.57	$ 102.99	$ 105.55
3rd Quarter	$ 4.07	$ 0.24	$ 1.04	$ 1.25	$ 1.28	$ 2.11	$ 0.71	$ 0.58	$ 97.21	$ 100.94
4th Quarter	$ 4.04	$ 0.21	$ 0.76	$ 0.98	$ 0.99	$ 1.49	$ 0.69	$ 0.52	$ 73.15	$ 76.08
2014 Averages	$ 4.43	$ 0.27	$ 1.04	$ 1.22	$ 1.25	$ 1.98	$ 0.71	$ 0.57	$ 93.01	$ 96.75
2015 by quarter:										
1st Quarter	$ 2.99	$ 0.19	$ 0.53	$ 0.68	$ 0.68	$ 1.10	$ 0.50	$ 0.37	$ 48.63	$ 52.83
2nd Quarter	$ 2.65	$ 0.18	$ 0.46	$ 0.59	$ 0.60	$ 1.26	$ 0.42	$ 0.29	$ 57.94	$ 62.97
2015 Averages	$ 2.82	$ 0.19	$ 0.49	$ 0.64	$ 0.64	$ 1.18	$ 0.46	$ 0.33	$ 53.29	$ 57.90

(1) Natural gas prices are based on Henry-Hub Inside FERC commercial index prices as reported by Platts, which is a division of McGraw Hill Financial, Inc.
(2) NGL prices for ethane, propane, normal butane, isobutane and natural gasoline are based on Mont Belvieu Non-TET commercial index prices as reported by Oil Price Information Service.
(3) Polymer grade propylene prices represent average contract pricing for such product as reported by Chemical Market Associates, Inc. ("CMAI"). Refinery grade propylene prices represent weighted-average spot prices for such product as reported by CMAI.
(4) Crude oil prices are based on commercial index prices for WTI as measured on the New York Mercantile Exchange ("NYMEX") and for LLS as reported by Platts.

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 market price of WTI crude oil (as measured on the NYMEX) averaged $57.94 per barrel in the second quarter of 2015 compared to $102.99 per barrel in the second quarter of 2014. The market price of WTI crude oil (as measured on the NYMEX) averaged $53.29 per barrel during the six months ended June 30, 2015 compared to $100.84 per barrel during the same period in 2014. Crude oil prices have been depressed since the fourth quarter of 2014 due to the current worldwide oversupply situation.

§ The market price of natural gas (as measured at the Henry Hub in Louisiana) averaged $2.65 per MMBtu in the second quarter of 2015 compared to $4.68 per MMBtu in the second quarter of 2014. The market price of natural gas (as measured at the Henry Hub in Louisiana) averaged $2.82 per MMBtu during the six months ended June 30, 2015 versus $4.81 per MMBtu during the same period in 2014. Natural gas prices in the second quarter of 2014 were higher due to unusually cold weather during that period. Prices in the second quarter of 2015 decreased primarily due to higher natural gas inventory levels in storage.

§ The weighted-average indicative market price for NGLs (based on prices for such products at Mont Belvieu, Texas, which is the primary industry hub for domestic NGL production) was $0.52 per gallon in the second quarter of 2015 compared to $1.03 per gallon in the second quarter of 2014. In general, NGL prices have declined since the fourth quarter of 2014 due to oversupply of certain products and lower crude oil prices. The weighted-average indicative market price for NGLs was $0.53 per gallon during the six months ended June 30, 2015 versus $1.08 per gallon during the same period in 2014.

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

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

Consolidated Income Statement Highlights
The following information highlights significant changes in our comparative income statement amounts and the primary drivers of such changes.

Revenues

Second Quarter of 2015 compared to Second Quarter of 2014. Total revenues for the second quarter of 2015 decreased $5.43 billion when compared to total revenues for the second quarter of 2014. Revenues from the marketing of NGLs, crude oil and petrochemicals decreased a net $4.88 billion quarter-to-quarter primarily due to lower sales prices, which accounted for a $5.41 billion decrease, partially offset by higher sales volumes, which accounted for a $529.8 million increase. Revenues from the marketing of natural gas and refined products decreased $606.5 million quarter-to-quarter primarily due to lower sales prices. Revenues from midstream services increased $66.0 million quarter-to-quarter primarily from services provided by the marine terminal assets we now own due to our acquisition of Oiltanking effective October 1, 2014.

Six Months Ended June 30, 2015 compared to Six Months Ended June 30, 2014. For the six months ended June 30, 2015, total revenues decreased $10.87 billion when compared to total revenues for the six months ended June 30, 2014. Revenues from the marketing of NGLs, crude oil, petrochemicals and refined products decreased a net $10.19 billion period-to-period primarily due to lower sales prices, which accounted for an $11.16 billion decrease, partially offset by higher sales volumes, which accounted for a $964.0 million increase. Revenues from the marketing of natural gas decreased $834.2 million period-to-period primarily due to lower sales prices. Revenues from midstream services increased $168.2 million period-to-period primarily due to the ongoing expansion of our operations. Recently completed assets such as the ATEX pipeline and a portion of the Aegis Ethane Pipeline and expanded crude oil storage capacity at our ECHO terminal contributed approximately $65 million of this period-to-period increase. Revenues for the six months ended June 30, 2015 include $107.2 million from services provided by the marine terminal assets we now own due to our acquisition of Oiltanking effective October 1, 2014.

Operating costs and expenses

Second Quarter of 2015 compared to Second Quarter of 2014. Total operating costs and expenses for the second quarter of 2015 decreased $5.28 billion when compared to total operating costs and expenses for the second quarter of 2014. The cost of sales associated with our marketing of NGLs, crude oil and petrochemicals decreased a net $4.9 billion quarter-to-quarter primarily due to lower purchase prices, which accounted for a $5.34 billion decrease, partially offset by higher sales volumes, which accounted for a $443.9 million increase. The cost of sales associated with our marketing of natural gas and refined products decreased $547.7 million quarter-to-quarter primarily due to lower purchase prices.

Other operating costs and expenses increased $8.0 million quarter-to-quarter. Other operating costs and expenses for the second quarter of 2015 includes $15.4 million of expenses attributable to the marine terminal assets we now own as a result of acquiring Oiltanking. This amount is partially offset by $8.5 million of terminaling fees that we paid Oiltanking during the second quarter of 2014.

Depreciation, amortization and accretion expenses included in operating costs and expenses for the second quarter of 2015 increased $73.2 million when compared to the second quarter of 2014. This quarter-to-quarter increase includes $25.8 million of depreciation and amortization expenses in the second quarter of 2015 attributable to our acquisition of Oiltanking. Results for the second quarter of 2015 also include $39.5 million of accretion expense resulting from a change in management's estimate associated with pending and future pipeline abandonment activities on our Matagorda Gathering System. For information regarding our asset retirement obligations, see Note 7 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Operating costs and expenses also include $79.0 million and $3.7 million of non-cash asset impairment charges for the second quarters of 2015 and 2014, respectively. Our non-cash asset impairment charges for the second quarter of 2015 primarily reflect the $54.8 million of expense we recorded in connection with the reclassification of our Offshore Business to assets held for sale at June 30, 2015. We completed this sale on July 24, 2015.

Six Months Ended June 30, 2015 compared to Six Months Ended June 30, 2014. For the six months ended June 30, 2015, total operating costs and expenses decreased $10.55 billion when compared to the six months ended June 30, 2014. The cost of sales associated with our marketing of NGLs, crude oil, petrochemicals and refined products decreased $10.1 billion period-to-period primarily due to lower purchase prices, which accounted for an $11.0 billion decrease, partially offset by higher sales volumes, which accounted for a $901.7 million increase. The cost of sales associated with our marketing of natural gas decreased $698.2 million period-to-period primarily due to lower purchase prices.

Other operating costs and expenses decreased $39.4 million period-to-period primarily due to lower fuel costs, which accounted for a $41.2 million decrease. Other operating costs and expenses for the six months ended June 30, 2015 includes $29.3 million of expenses attributable to the marine terminal assets we now own as a result of acquiring Oiltanking. This amount is partially offset by $17.1 million of terminaling fees that we paid Oiltanking during the six months ended June 30, 2014.

For the six months ended June 30, 2015, depreciation, amortization and accretion expenses included in operating costs and expenses increased $117.1 million when compared to the six months ended June 30, 2014 primarily due to the ongoing expansion of our operations. This period-to-period increase includes $49.7 million of depreciation and amortization expenses in the six months ended June 30, 2015 attributable to our acquisition of Oiltanking. The six months ended June 30, 2015 also include $39.5 million of accretion expense resulting from a change in management's estimate associated with pending and future pipeline abandonment activities on our Matagorda Gathering System.

During the six months ended June 30, 2014, we recognized $95.0 million of gains attributable to the receipt of nonrefundable cash insurance proceeds. These proceeds were attributable to property damage claims we filed in connection with the February 2011 NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility.

Operating costs and expenses also include $112.3 million and $12.5 million of non-cash asset impairment charges for the six months ended June 30, 2015 and 2014, respectively. As noted previously, we recorded a $54.8 million non-cash asset impairment charge for the six months ended June 30, 2015 in connection with the reclassification of our Offshore Business to assets held for sale at June 30, 2015. The remainder of our non-cash asset impairment charges for the six months ended June 30, 2015 primarily relate to the abandonment of certain crude oil and natural gas pipeline assets in Texas.

General and administrative costs

General and administrative costs for the second quarter of 2015 decreased $2.8 million when compared to the second quarter of 2014. For the six months ended June 30, 2015, general and administrative costs decreased $6.7 million when compared to the six months ended June 30, 2014 primarily due to costs we incurred during the first quarter of 2014 for the settlement of litigation associated with our merger in 2010 with Enterprise GP Holdings L.P.

Equity in income of unconsolidated affiliates

Equity income from our unconsolidated affiliates increased $59.9 million for the second quarter of 2015 and $92.6 million for the six months ended June 30, 2015 when compared to the same respective periods in 2014. These increases are primarily due to increased earnings from our investments in crude oil and NGL pipeline joint ventures.

Interest expense
Interest expense increased $11.5 million for the second quarter of 2015 and $29.7 million for the six months ended June 30, 2015 when compared to the same respective periods in 2014. The following table presents the components of our consolidated interest expense for the periods indicated (dollars in millions):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
Interest charged on debt principal outstanding	$ 266.0	$ 240.4	$ 523.1	$ 473.3
Impact of interest rate hedging program, including related amortization	4.2	1.6	8.9	3.0
Interest costs capitalized in connection with construction projects (1)	(35.7)	(17.7)	(65.3)	(36.2)
Other (2)	5.9	4.6	12.8	9.7
Total	$ 240.4	$ 228.9	$ 479.5	$ 449.8

(1) Capitalized interest amounts become part of the historical cost of an asset and are charged to earnings (as a component of depreciation expense) ratably over the estimated useful life of the asset once the asset enters its intended service. Capitalized interest amounts fluctuate based on the timing of when projects are placed into service, our capital spending levels and the interest rates charged on borrowings.
(2) Primarily reflects facility commitment fees charged in connection with our revolving credit facilities and amortization of debt issuance costs.

Interest charged on debt principal outstanding, which is the primary driver of interest expense, increased a net $25.6 million quarter-to-quarter primarily due to increased debt principal amounts outstanding during the second quarter of 2015, which accounted for a $46.0 million increase, partially offset by the effect of lower overall interest rates in the second quarter of 2015, which accounted for a $20.4 million decrease. Our weighted-average debt principal balance for the second quarter of 2015 was $22.07 billion compared to $18.38 billion for the second quarter of 2014. In general, our debt principal balances have increased over time due to the partial debt financing of our capital spending program. For a discussion of our consolidated debt obligations and capital spending program, see “Liquidity and Capital Resources” within this Part I, Item 2.

For the six months ended June 30, 2015, interest charged on debt principal outstanding increased a net $49.8 million period-to-period primarily due to increased debt principal amounts outstanding during the first six months of 2015, which accounted for a $92.4 million increase, partially offset by the effect of lower overall interest rates in the first six months of 2015, which accounted for a $42.6 million decrease. Our weighted-average debt principal balance for the first six months of 2015 was $21.91 billion compared to $18.03 billion for the first six months of 2014.

Change in fair value of Liquidity Option Agreement
Results for the three and six months ended June 30, 2015 include $11.5 million of accretion expense we recorded to recognize changes in the fair value of the Liquidity Option Agreement. For information regarding the Liquidity Option Agreement, see Note 15 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Income taxes
Income taxes for the second quarter of 2015 were a benefit of $7.9 million compared to an expense of $10.0 million for the second quarter of 2014 primarily due to changes in our accruals for state tax obligations under the Revised Texas Franchise Tax (or “Texas Margin Tax”). In June 2015, the State of Texas enacted certain changes to the Texas Margin Tax that lowered the tax rate. As a result of this change, our accruals for the Texas Margin Tax were reduced and we recorded a $16.3 million benefit in the second quarter of 2015.

For the six months ended June 30, 2015, income taxes were a benefit of $1.1 million compared to an expense of $14.8 million for the same period in 2014. As discussed above, the period-to-period change is primarily due to the $16.3 million benefit recorded in 2015 related to the Texas Margin Tax.

Noncontrolling interests

Net income attributable to noncontrolling interests decreased $3.2 million for the second quarter of 2015 when compared to the second quarter of 2014. For the six months ended June 30, 2015, net income attributable to noncontrolling interests increased $3.4 million when compared to the six months ended June 30, 2014 primarily due to the inclusion of noncontrolling interests in Oiltanking from January 1, 2015 to February 13, 2015, which is the date we completed the Oiltanking acquisition.

Business Segment Highlights

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. The following table presents gross operating margin by segment for the periods indicated (dollars in millions):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
NGL Pipelines & Services	$ 650.6	$ 680.9	$ 1,345.8	$ 1,460.9
Crude Oil Pipelines & Services	235.6	184.0	449.6	343.7
Natural Gas Pipelines & Services	191.4	203.0	395.9	423.4
Petrochemical & Refined Products Services	181.3	161.7	355.9	292.1
Offshore Pipelines & Services	44.3	33.6	90.4	72.9
Total	$ 1,303.2	$ 1,263.2	$ 2,637.6	$ 2,593.0

For additional information regarding our use of this non-GAAP financial measure, see “Other Items – Use of Non-GAAP Financial Measures” within this Part I, Item 2.

The following information highlights significant changes in our quarterly and year-to-date 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.

NGL Pipelines & Services

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
Segment gross operating margin:				
Natural gas processing and related NGL marketing activities	$ 220.3	$ 265.7	$ 460.5	$ 614.9
NGL pipelines and related storage	311.7	261.0	639.9	551.2
NGL fractionation	118.6	154.2	245.4	294.8
Total	$ 650.6	$ 680.9	$ 1,345.8	$ 1,460.9
Selected volumetric data:				
NGL transportation volumes (MBPD)	2,974	2,866	2,833	2,855
NGL fractionation volumes (MBPD)	822	845	810	819
Equity NGL production (MBPD) (1)	123	136	129	136
Fee-based natural gas processing (MMcf/d) (2)	4,912	4,941	4,848	4,829

(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.

Natural gas processing and related NGL marketing activities. Gross operating margin from natural gas processing and related NGL marketing activities for the second quarter of 2015 decreased $45.4 million when compared to the second quarter of 2014. Gross operating margin from our NGL marketing activities for the second quarter of 2015 increased a net $11.7 million when compared to the second quarter of 2014 primarily due to higher sales volumes, which accounted for a $60.9 million increase, partially offset by a $48.7 million decrease due to lower sales margins. Volatility in energy commodity market prices during the second quarter of 2015 created opportunities for increased NGL marketing sales volumes when compared to the second quarter of 2014. Gross operating margin from our natural gas processing plants decreased $57.1 million quarter-to-quarter in the aggregate primarily due to lower processing margins.

For the six months ended June 30, 2015, gross operating margin from natural gas processing and related NGL marketing activities decreased $154.4 million when compared to the same period in 2014. Gross operating margin from our NGL marketing activities for the six months ended June 30, 2015 decreased a net $47.5 million when compared to the six months ended June 30, 2014 primarily due to lower sales margins, which accounted for a $135.6 million decrease, partially offset by a $90.2 million increase due to higher sales volumes. During the six months ended June 30, 2015, a higher percentage of volume in the LPG export business was associated with long-term, fee-based marketing contracts compared to spot business, which is typically contracted at higher margins, in the six months ended June 30, 2014. Gross operating margin from our natural gas processing plants decreased $106.9 million period-to-period in the aggregate primarily due to lower processing margins.

NGL pipelines and related storage. Gross operating margin from NGL pipelines and related storage assets for the second quarter of 2015 increased $50.7 million when compared to the second quarter of 2014. Gross operating margin from our Houston Ship Channel marine terminal and related pipeline increased $21.3 million quarter-to-quarter, of which $13.8 million of the increase is attributable to our acquisition of Oiltanking and $7.5 million to a combined 100 MBPD increase in volumes.

Gross operating margin from the Chaparral Pipeline, Mid-America Pipeline System, Seminole Pipeline and related terminals increased $17.5 million quarter-to-quarter. Higher transportation tariffs and other fees, which accounted for a $19.5 million quarter-to-quarter increase in gross operating margin and a $9.0 million quarter-to-quarter decrease in operating expenses, were partially offset by an $11.0 million decrease in gross operating margin attributable to lower transportation volumes. Transportation volumes on these three pipelines decreased a combined 79 MBPD quarter-to-quarter due in part to lower recoveries of ethane during the second quarter of 2015 when compared to the second quarter of 2014. Lower recoveries of ethane at upstream natural gas processing plants served by these pipelines results in lower volumes of ethane available for transportation.

Gross operating margin from our investments in the Front Range Pipeline, Texas Express Pipeline and Texas Express Gathering System for the second quarter of 2015 increased $3.4 million primarily due to a combined 26 MBPD increase in transportation volumes (net to our interest) when compared to the second quarter of 2014. Lastly, gross operating margin from our NGL pipelines and related storage assets increased $6.7 million quarter-to-quarter as a result of net operational measurement losses in the second quarter of 2014 that did not reoccur in the second quarter of 2015.

For the six months ended June 30, 2015, gross operating margin from NGL pipelines and related storage assets increased $88.7 million when compared to the same period in 2014. Gross operating margin from our Houston Ship Channel marine terminal and related pipeline increased $42.0 million period-to-period, of which $28.4 million of the increase is attributable to our acquisition of Oiltanking and $13.6 million due to a combined 78 MBPD increase in volumes.

For the six months ended June 30, 2015, gross operating margin from the Chaparral Pipeline, Mid-America Pipeline System, Seminole Pipeline and related terminals increased $18.9 million period-to-period when compared to the same period in 2014. Higher transportation tariffs and other fees, which accounted for a $35.1 million period-to-period increase in gross operating margin and a $26.4 million period-to-period decrease in operating expenses were partially offset by a $42.6 million decrease in gross operating margin attributable to lower transportation volumes. Transportation volumes on these three pipelines for the six months ended June 30, 2015 decreased a combined 149 MBPD due in part to lower recoveries of ethane when compared to the same period in 2014.

For the six months ended June 30, 2015, gross operating margin from our investments in the Front Range Pipeline, Texas Express Pipeline and Texas Express Gathering System increased $11.2 million primarily due to a combined 35 MBPD increase in transportation volumes (net to our interest) when compared to the same period in 2014. Gross operating margin from our ATEX pipeline increased $5.0 million period-to-period primarily due to higher transportation volumes of 24 MBPD. Lastly, gross operating margin from our NGL pipelines and related storage assets increased $14.7 million period-to-period as a result of net operational measurement losses in the first six months of 2014 that did not reoccur in the first six months of 2015.

NGL fractionation. Gross operating margin from NGL fractionation for the second quarter of 2015 decreased $35.6 million when compared to the second quarter of 2014. Gross operating margin from our Mont Belvieu NGL fractionators decreased $30.4 million quarter-to-quarter primarily due to a combined $20.4 million decrease in fractionation fees and product blending revenues and an $8.2 million decrease due to lower NGL fractionation volumes of 30 MBPD (net to our interest). When compared to the second quarter of 2014, the decrease in NGL fractionation volumes for Mont Belvieu for the second quarter of 2015 is primarily due to (i) lower recoveries of ethane at upstream natural gas processing plants and (ii) plant processing limitations encountered due to higher levels of propane and butane in the mixed NGL stream being fractionated due to the lower recoveries of ethane. Gross operating margin from our Hobbs NGL fractionator in Gaines County, Texas decreased $3.9 million quarter-to-quarter primarily due to lower product blending revenues, which accounted for a $2.7 million decrease in gross operating margin, and lower fractionation volumes of 12 MBPD, which accounted for an additional $1.6 million decrease.

For the six months ended June 30, 2015, gross operating margin from NGL fractionation decreased $49.4 million when compared to the same period in 2014. Gross operating margin from our Mont Belvieu NGL fractionators decreased $37.0 million period-to-period primarily due to lower fractionation fees and product blending revenues. Our NGL fractionation volumes in Mont Belvieu decreased 2 MBPD (net to our interest) period-to-period. Gross operating margin from our Hobbs NGL fractionator in Gaines County, Texas decreased $8.5 million period-to-period primarily due to lower fractionation volumes of 16 MBPD. Gross operating margin from our Norco NGL fractionator in Louisiana decreased $3.6 million period-to-period primarily due to lower revenues from product blending and percent-of-liquids contracts attributable to lower energy commodity prices.

Crude Oil Pipelines & Services

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
Segment gross operating margin	$ 235.6	$ 184.0	$ 449.6	$ 343.7
Selected volumetric data:				
Crude oil transportation volumes (MBPD)	1,469	1,297	1,427	1,279

Gross operating margin from our Crude Oil Pipelines & Services segment for the second quarter of 2015 increased $51.6 million when compared to the second quarter of 2014. Gross operating margin from crude oil terminaling services at our Houston Ship Channel facility, which we now own due to our acquisition of Oiltanking in October 2014, contributed $36.6 million to our results in the second quarter of 2015. Gross operating margin from our equity investment in the Seaway Pipeline increased $28.0 million quarter-to-quarter primarily due to contributions from the Seaway Loop, which commenced operations in December 2014. Seaway's transportation volumes increased 153 MBPD quarter-to-quarter (net to our interest) attributable to an increase in long-haul volumes.

Gross operating margin from our West Texas System increased $5.6 million quarter-to-quarter primarily due to higher volumes of 30 MBPD, which accounted for a $2.5 million increase, and an operational measurement loss of $3.1 million in the second quarter of 2014 that did not reoccur in the second quarter of 2015.

Gross operating margin from our South Texas Crude Oil Pipeline System decreased $20.2 million quarter-to-quarter primarily due to a 34 MBPD decrease in volumes, which accounted for a $7.5 million decrease, and lower crude oil prices, which was the primary driver of a $14.3 million decrease in gross operating margin from net operating gains and losses. The decrease in crude oil transportation volumes was attributable to lower volumes from legacy fields in South Texas and the abandonment of certain segments of pipeline, which more than offset an increase in transportation volumes attributable to Eagle Ford production.

For the six months ended June 30, 2015, gross operating margin from our Crude Oil Pipelines & Services segment increased $105.9 million when compared to the same period in 2014. Gross operating margin from crude oil terminaling services at our Houston Ship Channel facility contributed $62.0 million in the six months ended June 30, 2015. In addition, gross operating margin from our equity investment in the Seaway Pipeline increased $50.6 million period-to-period primarily due to contributions from the Seaway Loop. Seaway's transportation volumes increased a net 95 MBPD period-to-period (net to our interest) with a 109 MBPD increase in long-haul volumes partially offset by a 14 MBPD decrease in combined short-haul volumes on the Texas City and Freeport Systems.

Gross operating margin from our Red River System increased $8.9 million period-to-period primarily due to a $4.4 million decrease in operating expenses, with the remaining period-to-period increase in gross operating margin primarily due to higher operating gains during the six months ended June 30, 2015 when compared to the same period in 2014. Gross operating margin from our West Texas System increased $5.9 million period-to-period primarily due to higher volumes of 30 MBPD. Gross operating margin from our South Texas Crude Oil Pipeline System decreased $22.2 million period-to-period primarily due to lower crude oil prices, which was the primary driver of an $18.9 million decrease in gross operating margin from net operating gains and losses.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
Segment gross operating margin	$ 191.4	$ 203.0	$ 395.9	$ 423.4
Selected volumetric data:				
Natural gas transportation volumes (BBtus/d)	12,488	12,617	12,496	12,569

Gross operating margin from our Natural Gas Pipelines & Services segment for the second quarter of 2015 decreased $11.6 million when compared to the second quarter of 2014. Gross operating margin from our San Juan Gathering System decreased $11.3 million quarter-to-quarter primarily due to lower energy commodity prices. Lower gathering fees, which are indexed to natural gas prices, resulted in a $4.7 million quarter-to-quarter decrease in gross operating margin. Condensate and natural gas sales margins on our San Juan Gathering System decreased a combined $4.3 million quarter-to-quarter primarily due to lower commodity prices. Gross operating margin from our Haynesville Gathering System decreased $2.8 million quarter-to-quarter primarily due to a 74 BBtus/d decrease in gathering volumes. Gross operating margin from our Jonah Gathering System increased $4.1 million quarter-to-quarter primarily due to higher volumes of 121 BBtus/d, which accounted for a $3.0 million increase, and higher gathering fees, which accounted for an additional $3.1 million increase, partially offset by the impact of higher maintenance expenses in the second quarter of 2015.

For the six months ended June 30, 2015, gross operating margin from our Natural Gas Pipelines & Services segment decreased $27.5 million when compared to the same period in 2014. Gross operating margin from our San Juan Gathering System decreased $19.4 million period-to-period primarily due to an $11.7 million decrease in gathering fees, which are indexed to natural gas prices, and a $7.0 million decrease in condensate sales primarily resulting from lower sales prices. Gross operating margin from our Texas Intrastate System decreased $13.4 million period-to-period primarily due to an increase in maintenance and other operating expenses. Gross operating margin from our Haynesville Gathering System decreased $5.6 million period-to-period primarily due to an 84 BBtus/d decrease in gathering volumes. Gross operating margin from our Jonah Gathering System increased $9.0 million period-to-period primarily due to higher volumes of 112 BBtus/d, which accounted for a $5.4 million increase, and higher gathering fees, which accounted for an additional $5.1 million increase.

Petrochemical & Refined Products Services

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
Segment gross operating margin:				
Propylene fractionation and related activities	$ 34.2	$ 42.0	$ 98.6	$ 91.0
Butane isomerization and related operations	19.1	32.0	26.0	54.2
Octane enhancement and related plant operations	68.2	46.3	69.3	46.5
Refined products pipelines and related activities	44.0	23.5	130.3	66.1
Marine transportation and other	15.8	17.9	31.7	34.3
Total	$ 181.3	$ 161.7	$ 355.9	$ 292.1
Selected volumetric data:				
Propylene fractionation volumes (MBPD)	68	71	71	72
Butane isomerization volumes (MBPD)	98	105	80	93
Standalone DIB processing volumes (MBPD)	82	83	74	79
Octane additive and related plant production volumes (MBPD)	24	20	16	13
Transportation volumes, primarily refined products and petrochemicals (MBPD)	875	804	840	778

Propylene fractionation and related activities. Gross operating margin from our propylene fractionation and related activities for the second quarter of 2015 decreased $7.8 million when compared to the second quarter of 2014. Gross operating margin from our propylene fractionation plants in Mont Belvieu, Texas decreased $16.8 million quarter-to-quarter primarily due to maintenance expenses for work we completed during the second quarter of 2015. Gross operating margin from our propylene rail terminal at Mont Belvieu increased $1.8 million quarter-to-quarter primarily due to higher volumes, which accounted for a $1.1 million increase, and due to higher fees, which accounted for an additional $0.7 million increase. Gross operating margin from the remainder of this business increased $7.2 million quarter-to-quarter primarily due to expenses for operational measurement losses in the second quarter of 2014.

For the six months ended June 30, 2015, gross operating margin from our propylene fractionation and related activities increased $7.6 million when compared to the same period in 2014. Gross operating margin from our propylene fractionation plants in Mont Belvieu, Texas decreased $3.0 million period-to-period. Operating expenses at these plants increased $20.9 million period-to-period primarily due to maintenance activities we completed during the first six months of 2015, partially offset by a $17.9 million increase in gross operating margin period-to-period primarily due to higher propylene sales margins. Gross operating margin from our propylene rail terminal at Mont Belvieu increased $2.7 million period-to-period primarily due to higher volumes, which accounted for a $1.0 million increase, and higher fees, which accounted for an additional $1.6 million increase. Gross operating margin from the remainder of this business increased $7.9 million period-to-period primarily due to expenses for operational measurement losses in the first six months of 2014.

Butane isomerization and deisobutanizer operations. Gross operating margin from our butane isomerization and deisobutanizer (“DIB”) operations for the second quarter of 2015 decreased $12.9 million when compared to the second quarter of 2014 primarily due to lower by-product sales revenues. By-product sales revenues decreased $12.2 million quarter-to-quarter, of which $9.9 million is due to lower sales prices and the remaining $2.3 million is due to lower sales volumes.

For the six months ended June 30, 2015, gross operating margin from our butane isomerization and DIB operations decreased $28.2 million when compared to the same period in 2014 primarily due to lower by-product sales revenues and lower isomerization volumes. By-product sales revenues decreased $22.2 million period-to-period, of which $16.6 million is due to lower sales prices and the remaining $5.6 million is due to lower sales volumes. Gross operating margin decreased $4.6 million period-to-period attributable to a 13 MBPD decrease in isomerization volumes.

Octane enhancement and HPIB plant operations. Gross operating margin from our octane enhancement facility and high purity isobutylene ("HPIB") plant for the second quarter of 2015 increased $21.9 million when compared to the second quarter of 2014. The quarter-to-quarter increase in gross operating margin is primarily due to higher sales volumes, which accounted for a $15.2 million increase, and higher sales margins, which accounted for an additional $5.8 million increase.

For the six months ended June 30, 2015, gross operating margin from our octane enhancement facility and HPIB plant increased $22.8 million when compared to the same period in 2014. The period-to-period increase in gross operating margin is primarily due to higher sales volumes during the first six months of 2015 when compared to the first six months of 2014.

Refined products pipelines and related activities. Gross operating margin from refined products pipelines and related marketing activities for the second quarter of 2015 increased $20.5 million when compared to the second quarter of 2014. Gross operating margin for the second quarter of 2015 includes $7.6 million and $4.8 million from refined products terminaling services provided at our Beaumont Marine West terminal and Houston Ship Channel terminal, respectively. We own these terminals due to our acquisition of Oiltanking effective October 1, 2014. Gross operating margin from our Beaumont Refined Products Export terminal, which we reactivated in May 2014, increased $6.3 million quarter-to-quarter on higher throughput volumes of 50 MBPD.

For the six months ended June 30, 2015, gross operating margin from refined products pipelines and related marketing activities increased $64.2 million when compared to the same period in 2014. Gross operating margin from our TE Products Pipeline and related refined products terminals increased $26.5 million period-to-period primarily due to higher tariffs and other fees, which accounted for an $11.2 million increase, and a $16.9 million period-to-period decrease in operating expenses. Overall, transportation volumes on the TE Products Pipeline increased a net 39 MBPD period-to-period primarily due to higher refined products and petrochemical transportation volumes. Gross operating margin from our Beaumont Refined Products Export terminal, which we reactivated in May 2014, increased $12.4 million period-to-period on higher volumes of 34 MBPD.

For the six months ended June 30, 2015, gross operating margin includes $15.4 million and $10.4 million from refined products terminaling services provided at our Beaumont Marine West terminal and Houston Ship Channel terminal, respectively.

Offshore Pipelines & Services

As discussed in "Significant Recent Developments," we sold our Offshore Business to Genesis in July 2015. The following table presents segment gross operating margin and selected volumetric data for the Offshore Pipelines & Services segment for the periods indicated (dollars in millions, volumes as noted):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	**2014**	**2015**	**2014**
Segment gross operating margin	$ 44.3	$ 33.6	$ 90.4	$ 72.9
Selected volumetric data:				
Natural gas transportation volumes (BBtus/d)	561	609	590	589
Crude oil transportation volumes (MBPD)	372	318	358	326
Platform natural gas processing (MMcf/d)	83	152	103	150
Platform crude oil processing (MBPD)	13	9	14	13

Gross operating margin from our Offshore Pipelines & Services segment for the second quarter of 2015 increased $10.7 million when compared to the second quarter of 2014. Gross operating margin for the second quarter of 2015 includes $9.5 million of equity earnings from our investment in the SEKCO Oil Pipeline, which started earning firm capacity reservation fees in the third quarter of 2014. Net to our interest, transportation volumes on the SEKCO Oil Pipeline were 35 MBPD during the second quarter of 2015. Equity earnings from our investment in the Poseidon Oil Pipeline increased $3.7 million quarter-to-quarter. The Poseidon Oil Pipeline receives crude oil volumes from the SEKCO Oil Pipeline for further transportation to shore. Aggregate gross operating margin from our Independence Hub platform and Independence Trail pipeline decreased $4.5 million quarter-to-quarter primarily due to lower platform processing and pipeline transportation volumes during the second quarter of 2015.

For the six months ended June 30, 2015, gross operating margin from our Offshore Pipelines & Services segment increased $17.5 million when compared to the same period in 2014. Gross operating margin for the six months ended June 30, 2015 includes $18.7 million of equity earnings from our investment in the SEKCO Oil Pipeline, which started earning firm capacity reservation fees in the third quarter of 2014. Net to our interest, transportation volumes on the SEKCO Oil Pipeline were 28 MBPD during the first six months of 2015. Equity earnings from our investment in the Poseidon Oil Pipeline increased $4.6 million period-to-period. Aggregate gross operating margin from our Independence Hub platform and Independence Trail pipeline decreased $7.2 million period-to-period primarily due to lower platform processing and pipeline transportation volumes during the six months ended June 30, 2015.

Liquidity and Capital Resources

At June 30, 2015, we had $5.55 billion of consolidated liquidity, which was comprised of $551.1 million of unrestricted cash on hand and $5.0 billion of available borrowing capacity under EPO's revolving credit facilities. 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 for the reasonably foreseeable future.

We expect to issue additional equity and debt securities to assist us in meeting our future funding and liquidity requirements, including those related to capital spending. We have a universal shelf registration statement (the "2013 Shelf") on file with the SEC. The 2013 Shelf allows Enterprise Products Partners L.P. and EPO (on a standalone basis) to issue an unlimited amount of equity and debt securities, respectively. We issued $2.5 billion of senior notes under the 2013 Shelf in May 2015 (see below).

Consolidated Debt

The following table presents scheduled maturities of our consolidated debt obligations outstanding at June 30, 2015 for the years indicated (dollars in millions):

		Scheduled Maturities of Debt					
	Total	Remainder of 2015	2016	2017	2018	2019	Thereafter
Senior Notes	$ 20,800.0	$ 650.0	$ 750.0	$ 800.0	$ 1,100.0	$ 1,500.0	$ 16,000.0
Junior Subordinated Notes	1,532.7	--	--	--	--	--	1,532.7
Total	$ 22,332.7	$ 650.0	$ 750.0	$ 800.0	$ 1,100.0	$ 1,500.0	$ 17,532.7

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

Issuance of $2.5 Billion of Senior Notes in May 2015

In May 2015, EPO issued $750 million in principal amount of 1.65% senior notes due May 2018 ("Senior Notes OO"), $875 million in principal amount of 3.70% senior notes due February 2026 ("Senior Notes PP") and $875 million in principal amount of 4.90% senior notes due May 2046 ("Senior Notes QQ"). Senior Notes OO, PP and QQ were issued at 99.881%, 99.635% and 99.635% of their principal amounts, respectively.

Net proceeds from the issuance of these senior notes were used as follows: (i) the repayment of amounts outstanding under EPO's commercial paper program, which included amounts we used to repay $250 million in principal amount of Senior Notes I that matured in March 2015, (ii) the repayment of amounts outstanding at the maturity of our $400 million in principal amount of Senior Notes X that matured in June 2015 and (iii) for general company purposes.

Enterprise Products Partners L.P. has unconditionally guaranteed these senior notes 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 an indenture 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.

Issuance of Common Units

The following information describes significant transactions that affected our partners' equity accounts during the six months ended June 30, 2015:

Completion of Oiltanking Acquisition

On February 13, 2015, we issued 36,827,517 common units to the former public unitholders of Oiltanking as a result of completing Step 2 of the Oiltanking acquisition. See "Significant Recent Developments" within this Part I, Item 2 for additional information regarding the Oiltanking acquisition.

At-The-Market Program

On July 1, 2015, we filed a registration statement with the SEC covering the issuance of up to $1.92 billion of our common units in amounts, at prices and on terms to be determined by market conditions and other factors at the time of such offerings. Pursuant to this "at-the-market" program, we may sell common units under an equity distribution agreement between Enterprise Products Partners L.P. and certain broker-dealers from time-to-time by means of ordinary brokers' transactions through the NYSE at market prices, in block transactions or as otherwise agreed to with the broker-dealer parties to the agreement. The new registration statement was declared effective on August 3, 2015 and replaced our prior registration statement with respect to the at-the-market program, which was filed with the SEC in October 2013 and covered the issuance of up to $1.25 billion of our common units. Immediately prior to the effectiveness of the new registration statement, we had the capacity to issue additional common units under the at-the-market program up to an aggregate sales price of $424.6 million (after giving effect to sales of common units previously made under the program). Following the effectiveness of the new registration statement and after taking into account the aggregate sales price of common units sold under our at-the-market program through June 30, 2015 as described below, we now have the capacity to issue additional common units under our at-the-market program up to an aggregate sales price of $1.92 billion.

During the six months ended June 30, 2015, we issued 23,258,453 common units under this program for aggregate gross proceeds of $767.1 million. This includes 3,225,057 common units sold in March 2015 to a privately held affiliate of EPCO, which generated gross proceeds of $100 million. After taking into account applicable costs, our transactions under the at-the-market program resulted in aggregate net cash proceeds of $760.0 million for the first six months of 2015.

DRIP and EUPP

We also have registration statements on file with the SEC collectively authorizing the issuance of up to 140,000,000 of our common units in connection with a distribution reinvestment plan ("DRIP"). We issued a total of 5,453,541 common units under our DRIP during the six months ended June 30, 2015, which generated net cash proceeds of $177.8 million. After taking into account the number of common units issued under the DRIP through June 30, 2015, we have the capacity to issue an additional 22,027,808 common units under this plan.

During the six months ended June 30, 2015, affiliates of privately held EPCO reinvested $50 million, resulting in the issuance of 1,543,581 common units under our DRIP (this amount being a component of the total common units issued under the DRIP for the six months ended June 30, 2015).

In addition to the DRIP, we have registration statements on file with the SEC authorizing the issuance of up to 8,000,000 of our common units in connection with our employee unit purchase plan ("EUPP"). We issued 183,734 common units under our EUPP during the six months ended June 30, 2015, which generated net cash proceeds of $6.3 million. After taking into account the number of common units issued under the EUPP through June 30, 2015, we may issue an additional 6,969,334 common units under this plan.

Use of Proceeds

The net cash proceeds we received from the issuance of common units during the six months ended June 30, 2015 were used to temporarily reduce amounts outstanding under EPO's commercial paper program and revolving credit facility and for general company purposes.

For additional information regarding our issuance of common units and related registration statements, see Note 11 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Credit Ratings
As of August 1, 2015, the investment-grade credit ratings of EPO's long-term senior unsecured debt securities were BBB+ from Standard and Poor's and Baa1 from Moody's. In addition, the credit ratings of EPO's short-term senior unsecured debt securities were A-2 from Standard and Poor's and P-2 from Moody's. Fitch Ratings issued non-solicited ratings of BBB+ and F-2 for EPO's long-term senior unsecured debt securities and short-term senior unsecured debt securities, respectively.

EPO's credit ratings reflect only the view of a rating agency and should not be interpreted as a recommendation to buy, sell or hold any of our securities. A credit rating can be revised upward or downward or withdrawn at any time by a rating agency, if it determines that circumstances warrant such a change. A credit rating from one rating agency should be evaluated independently of credit ratings from other rating agencies.

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

	For the Six Months Ended June 30,	
	2015	**2014**
Net cash flows provided by operating activities	$ 1,901.6	$ 1,871.9
Cash used in investing activities	1,789.3	1,554.9
Cash provided by (used in) financing activities	364.4	(131.9)

Net cash flows provided by operating activities are largely dependent on earnings from our consolidated business activities. As a result, these cash flows are exposed to certain risks. We operate predominantly in the midstream energy industry. We provide products and services to producers and consumers of natural gas, NGLs, crude oil, refined products and petrochemicals. The products that we process, sell, transport or store are principally used as fuel for residential, agricultural and commercial heating; as feedstocks in petrochemical manufacturing; by crude oil refineries; and in the production of motor gasoline. Reduced demand for our services or products by industrial customers, whether because of a decline in general economic conditions, reduced demand for the end products made with our products, or increased competition from other service providers or producers due to pricing differences or other reasons, could have a negative impact on our earnings and operating cash flows. For a more complete discussion of these and other risk factors pertinent to our business, see "Risk Factors" under Part I, Item 1A of our 2014 Form 10-K and under Part II, Item 1A of this quarterly report.

Comparison of Six Months Ended June 30, 2015 with Six Months Ended June 30, 2014
The following information highlights significant period-to-period fluctuations in our consolidated cash flow amounts:

Operating Activities
Net cash flows provided by operating activities for the six months ended June 30, 2015 increased $29.7 million when compared to the same period in 2014. The increase in cash provided by operating activities was primarily due to:

§ a $108.4 million increase period-to-period in cash distributions from unconsolidated affiliates primarily due to improved results from our investments in crude oil and NGL pipeline joint ventures; partially offset by

§ a $26.6 million decrease in cash attributable to lower partnership income in the six months ended June 30, 2015 compared to the same period in 2014 (after adjusting our $246.0 million period-to-period decrease in net income for changes in the non-cash items identified on our Unaudited Condensed Statements of Consolidated Cash Flows); and

§ a $52.1 million period-to-period decrease in cash primarily due to the timing of cash receipts and payments related to operations.

For information regarding significant period-to-period changes in our consolidated net income and underlying segment results, see “Results of Operations” within this Part I, Item 2.

Investing Activities
Cash used in investing activities for the six months ended June 30, 2015 increased $234.4 million when compared to the same period in 2014 primarily due to:

§ a $457.7 million period-to-period increase in capital spending for consolidated property, plant and equipment, net of contributions in aid of construction costs;

§ a $95.0 million period-to-period decrease in cash proceeds from insurance recoveries (see Note 16 of the Notes to Unaudited Condensed Consolidated Financial Statements under Part I, Item 1 of this quarterly report for additional information regarding proceeds from insurance recoveries); and

§ a $55.0 million period-to-period change in restricted cash requirements; partially offset by

§ a $384.7 million period-to-period decrease in cash contributions to our unconsolidated affiliates primarily due to the completion of construction of the Front Range Pipeline and the Seaway Loop, partially offset by increased investments in the Eagle Ford Crude Oil Pipeline System.

Financing Activities
Our net cash provided by financing activities for the six months ended June 30, 2015 was $364.4 million compared to net cash used in financing activities of $131.9 million for the same period in 2014. The $496.3 million period-to-period change in cash flow from financing activities was primarily due to:

§ a $720.8 million period-to-period increase in net cash proceeds from the issuance of common units. We issued an aggregate 28,895,728 common units in connection with our at-the-market program, DRIP and EUPP during the six months ended June 30, 2015, which generated $944.1 million of net cash proceeds. This compares to an aggregate 6,630,272 common units we issued in connection with our at-the-market program, DRIP and EUPP during the same period in 2014, which collectively generated $223.3 million of net cash proceeds; partially offset by

§ a $148.9 million period-to-period increase in cash distributions paid to limited partners during the six months ended June 30, 2015 when compared to the same period in 2014. The increase in cash distributions is due to increases in both the number of distribution-bearing common units outstanding and the quarterly cash distribution rates per unit; and

§ an $88.2 million period-to-period decrease in net borrowings under our consolidated debt agreements. EPO issued $2.5 billion and repaid $650.0 million in principal amount of senior notes during the six months ended June 30, 2015, compared to the issuance of $2.0 billion and repayment of $500.0 million in principal amount of senior notes during the same period in 2014. In addition, net repayments under EPO’s commercial paper program were $909.4 million during the six months ended June 30, 2015 compared to $475.1 million during the same period in 2014.

Cash Distributions to Limited Partners
Our partnership agreement requires us to make quarterly distributions to our unitholders of all available cash, after any cash reserves established by Enterprise GP in its sole discretion. Cash reserves include those for the proper conduct of our business including, for example, those for capital expenditures, debt service, working capital, operating expenses, commitments and contingencies and other significant amounts. The retention of cash by the partnership allows us to reinvest in our growth and reduce our future reliance on the equity and debt capital markets. Based on the level of available cash, management proposes a quarterly cash distribution rate to the Board of Directors of Enterprise GP, which has sole authority in approving such matters. Unlike most master limited partnerships, our general partner has a non-economic ownership interest in us and is not entitled to receive any cash distributions from us based on IDRs or other equity interests.

We measure available cash by reference to distributable cash flow. The following table summarizes our calculation of distributable cash flow for the periods indicated (dollars in millions):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
Net income attributable to limited partners (1)	$ 551.0	$ 637.7	$ 1,187.1	$ 1,436.5
Adjustments to GAAP net income attributable to limited partners to derive non-GAAP distributable cash flow:				
Add depreciation, amortization and accretion expenses	407.5	331.1	774.9	651.0
Add non-cash asset impairment charges	79.0	3.7	112.3	12.5
Add losses or subtract gains attributable to asset sales and insurance recoveries, net	2.5	(6.8)	2.4	(96.4)
Add cash proceeds from asset sales and insurance recoveries (2)	5.4	16.9	5.9	113.2
Add changes in fair value of Liquidity Option Agreement (3)	11.5	--	11.5	--
Add cash distributions received from unconsolidated affiliates (4)	131.1	85.4	265.5	157.1
Subtract equity in income of unconsolidated affiliates (5)	(110.2)	(50.3)	(199.4)	(106.8)
Subtract sustaining capital expenditures (6)	(60.8)	(76.9)	(111.5)	(155.2)
Add deferred income tax expense or subtract benefit	(13.2)	0.4	(11.7)	0.6
Other, net	(16.3)	12.6	(19.8)	28.3
Distributable cash flow	$ 987.5	$ 953.8	$ 2,017.2	$ 2,040.8
Total cash distributions paid to limited partners with respect to period	$ 750.0	$ 661.0	$ 1,485.7	$ 1,311.5
Cash distributions per unit declared by Enterprise GP with respect to period (6)	$ 0.380	$ 0.360	$ 0.755	$ 0.715
Total distributable cash flow retained by partnership with respect to period (7)	$ 237.5	$ 292.8	$ 531.5	$ 729.3
Distribution coverage ratio (8)	1.3x	1.5x	1.4x	1.6x

(1) For a discussion of significant changes in our comparative income statement amounts underlying net income attributable to limited partners, along with the primary drivers of such changes, see "Consolidated Income Statements Highlights" within this Part I, Item 2.
(2) For a discussion of significant changes in cash proceeds from asset sales and insurance recoveries as presented in the investing activities section of our Unaudited Condensed Statements of Consolidated Cash Flows, see "Cash Flows from Operating, Investing and Financing Activities" within this Part I, Item 2.
(3) For information regarding our Liquidity Option Agreement, see Note 15 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.
(4) For information regarding our unconsolidated affiliates, see Note 8 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.
(5) For a discussion of our capital spending activity, see "Capital Spending" within this Part I, Item 2. Sustaining capital expenditures for each period include accruals.
(6) See Note 11 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report for additional information regarding our quarterly cash distributions declared with respect to the periods presented.
(7) At the sole discretion of Enterprise GP, cash retained by the partnership with respect to each of these years was primarily reinvested in our growth capital spending program, which substantially reduced our reliance on the equity and debt capital markets to fund such major expenditures.
(8) Distribution coverage ratio determined by dividing distributable cash flow by total cash distributions paid to limited partners and in connection with distribution equivalent rights with respect to the period.

For additional information regarding non-GAAP distributable cash flow, see "Other Items – Use of Non-GAAP Financial Measures" within this Part I, Item 2. Our use of distributable cash flow for the limited purposes described above and in this report is not a substitute for net cash flows provided by operating activities, the most comparable GAAP measure.

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, Mid-Continent and Northeast regions, including the Niobrara, Barnett, Eagle Ford, Permian, Haynesville, Marcellus and Utica Shale plays.

Although our focus in recent years has been 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 light of current business conditions, we expect that these opportunities will increase.

We placed approximately $300 million of major capital projects into service during the first six months of 2015. These projects included the expansion of our Houston Ship Channel LPG export terminal. We expect to complete construction and begin commercial operations of growth capital projects costing approximately $2.4 billion in the remainder of 2015. These projects include another significant expansion of our Houston Ship Channel LPG export terminal and various crude oil pipeline and storage products.

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

	For the Six Months Ended June 30, 2015	For the Six Months Ended June 30, 2014
Step 2 of Oiltanking acquisition (1)		
Equity instruments (36,827,517 common units of Enterprise)	$ 1,408.7	$ --
Capital spending for property, plant and equipment, net: (2)		
Growth capital projects (3)	1,516.6	1,019.5
Sustaining capital projects (4)	113.6	153.0
Investments in unconsolidated affiliates	114.1	498.8
Other investing activities	5.3	6.0
Total capital spending	$ 3,158.3	$ 1,677.3

(1) For a description of the acquisition of Oiltanking, see “Significant Recent Developments” within this Part I, Item 2.

(2) On certain of our capital projects, third parties are obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated with pipeline construction projects and production well tie-ins. Contributions in aid of construction costs were $7.8 million and $13.9 million for the six months ended June 30, 2015 and 2014, respectively. Growth and sustaining capital amounts presented in the table above are presented net of related contributions in aid of construction costs.

(3) Growth capital projects either (a) result in new sources of cash flow due to enhancements of or additions to existing assets (e.g., additional revenue streams, cost savings resulting from debottlenecking of a facility, etc.) or (b) expand our asset base through construction of new facilities that will generate additional revenue streams and cash flows.

(4) Sustaining capital expenditures are capital expenditures (as defined by GAAP) resulting from improvements to existing assets. Such expenditures serve to maintain existing operations but do not generate additional revenues or result in significant cost savings.

Fluctuations in our spending for growth capital projects and investments in unconsolidated affiliates are explained in large part by increases or decreases in spending on major expansion projects. Our most significant growth capital expenditures for the six months ended June 30, 2015 involved projects at our Houston LPG and ethane export terminals and Mont Belvieu complex.

Fluctuations in spending for sustaining capital projects are explained in large part by the timing and cost of pipeline integrity and similar projects.

Capital spending for the first six months of 2015 includes $1.4 billion of non-cash equity consideration we issued to complete Step 2 of the Oiltanking acquisition. Step 2 represented our acquisition of the noncontrolling interests in Oiltanking; therefore, approximately $1.4 billion of noncontrolling interests attributable to Oiltanking was reclassified to limited partners’ equity to reflect the February 2015 issuance of 36,827,517 Enterprise common units.

In total, capital spending for property, plant and equipment increased $457.7 million period-to-period primarily due to higher growth capital spending in the first six months of 2015. Growth capital spending at our Houston Ship Channel LPG and ethane export facilities increased a combined $262.5 million period-to-period as work continued at both locations. We recently completed an expansion project at our Houston Ship Channel LPG export terminal that increased our ability to load cargoes of fully refrigerated, low-ethane propane from 7.5 MMBbls per month to approximately 9.0 MMBbls per month. Work continues at this marine terminal facility on another expansion project that will increase our loading capacity from 9.0 MMBbls per month to in excess of 16.0 MMBbls per month. This expansion project is expected to be in service by the end of 2015. Work also continues at our Houston Ship Channel ethane export facility, which we expect to begin operations in the third quarter of 2016.

Growth capital spending on our Rancho II crude oil pipeline and the expansion of crude oil terminal assets at our ECHO, Houston Ship Channel and Beaumont Marine West terminals increased a combined $232.4 million period-to-period. The Rancho II crude oil pipeline consists of 88 miles of pipeline extending from Sealy, Texas to our ECHO terminal, and is expected to enter commercial service in September 2015. Current expansion projects at our ECHO, Houston Ship Channel and Beaumont Marine West terminals involve the construction of additional storage capacity and associated distribution pipelines. We continue to complete these terminal expansion projects in phases, with final completion expected in 2016.

Growth capital spending at our Mont Belvieu complex increased $127.7 million period-to-period primarily due to construction of our PDH facility, which is expected to begin commercial operations in September 2016. In addition, growth capital spending on our Gulf Coast ethane header system increased $78.2 million period-to-period. Our Gulf Coast ethane header system will be comprised of the newly constructed Aegis Ethane Pipeline and existing South Texas midstream infrastructure. When completed, this system will extend 500 miles from Corpus Christi, Texas to the Mississippi River in Louisiana.

Growth capital spending attributable to our ATEX pipeline and the Rocky Mountain expansion of our Mid-America Pipeline System decreased a combined $223.4 million period-to-period. Expansion projects involving these assets were largely completed prior to the first six months of 2015.

Investments in unconsolidated affiliates for the first six months of 2015 decreased $384.7 million when compared to the first six months of 2014 primarily due to completion of the Seaway Loop pipeline in December 2014.

Capital Spending Outlook

We currently expect our total capital spending for the remainder of 2015 to approximate $2.3 billion, which includes $200 million for sustaining capital expenditures. Our forecast of capital spending for the remainder of 2015 is based on our announced strategic operating and growth plans (through the filing date of this quarterly report), which are dependent upon our ability to generate the required funds from either operating cash flows or other means, including borrowings under debt agreements, the issuance of additional equity and debt securities, and potential divestitures. We may revise our forecast of capital spending due to factors beyond our control, such as adverse economic conditions, weather related issues and changes in supplier prices. 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 significant 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 expect to make the forecast capital expenditures noted above, we may adjust the timing and amounts of projected expenditures in response to changes in capital market conditions.

Pipeline Integrity Costs

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

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
Expensed	$ 16.3	$ 17.8	$ 30.2	$ 26.8
Capitalized	8.9	9.7	14.6	19.0
Total	$ 25.2	$ 27.5	$ 44.8	$ 45.8

We expect the cost of our pipeline integrity program, regardless of whether such costs are capitalized or expensed, to approximate $63 million for the remainder of 2015. The cost of our pipeline integrity program was $99 million for the year ended December 31, 2014.

Critical Accounting Policies and Estimates

A discussion of our critical accounting policies and estimates is included in our 2014 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 expenses.

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

Other Items

Use of Non-GAAP Financial Measures

Gross operating margin
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 executive 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. For additional information regarding gross operating margin, see Note 12 of the Notes to Unaudited Condensed Consolidated Financial Statements under Part I, Item 1 of this quarterly report.

The following table presents a reconciliation of non-GAAP total segment gross operating margin to GAAP operating income for the periods indicated (dollars in millions):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
Total segment gross operating margin	$ 1,303.2	$ 1,263.2	$ 2,637.6	$ 2,593.0
Adjustments to reconcile total segment gross operating margin to operating income:				
Subtract depreciation, amortization and accretion expense amounts not reflected in gross operating margin	(385.6)	(312.4)	(730.9)	(613.8)
Subtract impairment charges not reflected in gross operating margin	(79.0)	(3.7)	(112.3)	(12.5)
Add net gains or subtract net losses attributable to asset sales and insurance recoveries not reflected in gross operating margin	(2.5)	6.8	(2.4)	96.4
Subtract non-refundable deferred revenues attributable to shipper make-up rights on new pipeline projects reflected in gross operating margin	(5.2)	(21.9)	(35.9)	(45.2)
Add subsequent recognition of deferred revenues attributable to make-up rights not reflected in gross operating margin	14.3	--	34.4	--
Subtract general and administrative costs not reflected in gross operating margin	(44.9)	(47.7)	(94.2)	(100.9)
Operating income	$ 800.3	$ 884.3	$ 1,696.3	$ 1,917.0

<u>Distributable cash flow</u>

Our management compares the distributable cash flow we generate to the cash distributions we expect to pay our partners. Using this metric, management computes our distribution coverage ratio. Distributable cash flow is an important non-GAAP financial measure for our limited partners since it serves as an indicator of our success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not we are generating cash flows at a level that can sustain or support an increase in our quarterly cash distributions. Distributable cash flow is also a quantitative standard used by the investment community with respect to publicly traded partnerships because the value of a partnership unit is, in part, measured by its yield, which is based on the amount of cash distributions a partnership can pay to a unitholder. The GAAP measure most directly comparable to distributable cash flow is net cash flows provided by operating activities.

The following table presents a reconciliation of non-GAAP distributable cash flow to GAAP net cash flows provided by operating activities for the periods indicated (dollars in millions):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	2014	2015	2014
Distributable cash flow	$ 987.5	$ 953.8	$ 2,017.2	$ 2,040.8
Adjustments to reconcile distributable cash flow to net cash flows provided by operating activities:				
Add sustaining capital expenditures reflected in distributable cash flow	60.8	76.9	111.5	155.2
Subtract cash proceeds from asset sales and insurance recoveries reflected in distributable cash flow	(5.4)	(16.9)	(5.9)	(113.2)
Net effect of changes in operating accounts not reflected in distributable cash flow	(111.7)	(541.1)	(250.7)	(198.6)
Other, net	16.4	(4.9)	29.5	(12.3)
Net cash flows provided by operating activities	$ 947.6	$ 467.8	$ 1,901.6	$ 1,871.9

Contractual Obligations

Our consolidated principal debt obligations at June 30, 2015 were approximately $22.33 billion compared to $21.39 billion at December 31, 2014. For information regarding the scheduled maturities of such debt, see "Liquidity and Capital Resources – Consolidated Debt" within this Part I, Item 2. See Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements under Part I, Item 1 of this quarterly report for additional information regarding our consolidated debt obligations.

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, results of operations and cash flows.

Related Party Transactions
For information regarding our related party transactions, see Note 13 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 Part II, Item 7A, "Quantitative and Qualitative Disclosures About Market Risk," included in our 2014 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 exposure being managed.

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

Interest Rate Hedging Activities
We may utilize interest rate swaps, forward starting swaps and similar derivative instruments to manage our exposure to changes in interest rates charged on borrowings under certain consolidated debt agreements. This strategy is a component in controlling our overall cost of capital associated with such borrowings. The composition of our derivative instrument portfolios may change from period-to-period depending on our hedging requirements.

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

Interest rate swaps
Interest rate swaps exchange the stated interest rate paid on a notional amount of existing debt for the fixed or floating interest rate stipulated in the derivative instrument. The following table summarizes our portfolio of interest rate swaps at June 30, 2015 (dollars in millions):

Hedged Transaction	Number and Type of Derivatives Outstanding	Notional Amount	Period of Hedge	Rate Swap	Accounting Treatment
Senior Notes OO	10 fixed-to-floating swaps	$ 750.0	5/2015 to 5/2018	1.65% to 0.76%	Fair value hedge

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

Scenario	Resulting Classification	Portfolio Fair Value at December 31, 2014	Portfolio Fair Value at June 30, 2015	Portfolio Fair Value at July 15, 2015
Fair value assuming no change in underlying interest rates	*Asset*	$ --	$ 0.2	$ 1.5
Fair value assuming 10% increase in underlying interest rates	*Liability*	--	(2.3)	(0.8)
Fair value assuming 10% decrease in underlying interest rates	*Asset*	--	2.7	3.9

Commodity Hedging Activities

The prices of natural gas, NGLs, crude oil, refined products and petrochemical products are subject to fluctuations in response to changes in supply and demand, market conditions and a variety of additional factors that are beyond our control. In order to manage such price risks, we enter into commodity derivative instruments such as physical forward contracts, futures contracts, fixed-for-float swaps, basis swaps and option contracts.

The following table summarizes our portfolio of commodity derivative instruments outstanding at June 30, 2015 (volume measures as noted):

Derivative Purpose	Volume (1) Current (2)	Volume (1) Long-Term (2)	Accounting Treatment
Derivatives designated as hedging instruments:			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction (Bcf)	10.0	n/a	Cash flow hedge
Forecasted sales of NGLs (MMBbls) (3)	2.4	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchases of NGLs (MMBbls)	0.2	n/a	Cash flow hedge
Forecasted sales of octane enhancement products (MMBbls)	1.2	n/a	Cash flow hedge
Natural gas marketing:			
Forecasted purchases of natural gas for fuel (Bcf)	11.1	n/a	Cash flow hedge
Forecasted sales of natural gas (Bcf)	0.3	n/a	Cash flow hedge
Natural gas storage inventory management activities (Bcf)	9.3	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	27.5	n/a	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	32.1	n/a	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products (MMBbls)	4.9	n/a	Cash flow hedge
Forecasted sales of refined products (MMBbls)	1.5	n/a	Cash flow hedge
Refined products inventory management activities (MMBbls)	3.0	n/a	Fair value hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	7.8	0.8	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	10.6	0.8	Cash flow hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (Bcf) (4,5)	81.3	10.0	Mark-to-market
NGL risk management activities (MMBbls) (5)	8.2	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (5)	4.9	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 December 2016, April 2016 and March 2018, respectively.
(3) Forecasted sales of NGL volumes under natural gas processing exclude 1.3 MMBbls of additional hedges executed under contracts that have been designated as normal sales agreements.
(4) Current volumes include 55.2 Bcf of physical derivative instruments that are predominantly priced at a marked-based index plus a premium or minus a discount related to location differences.
(5) Reflects the use of derivative instruments to manage risks associated with transportation, processing and storage assets.

At June 30, 2015, our predominant commodity hedging strategies consisted of (i) hedging anticipated future purchases and sales of commodity products associated with transportation, storage and blending activities, (ii) hedging natural gas processing margins and (iii) hedging the fair value of commodity products held in inventory.

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

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

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

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

Scenario	Resulting Classification	Portfolio Fair Value at December 31, 2014	June 30, 2015	July 15, 2015
Fair value assuming no change in underlying commodity prices	*Asset (Liability)*	$ 5.8	$ (1.6)	$ (2.6)
Fair value assuming 10% increase in underlying commodity prices	*Asset (Liability)*	2.4	(6.3)	(7.5)
Fair value assuming 10% decrease in underlying commodity prices	*Asset*	9.2	3.0	2.3

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

Scenario	Resulting Classification	Portfolio Fair Value at December 31, 2014	June 30, 2015	July 15, 2015
Fair value assuming no change in underlying commodity prices	*Asset*	$ 57.8	$ 7.7	$ 34.8
Fair value assuming 10% increase in underlying commodity prices	*Asset (Liability)*	47.5	(17.5)	7.7
Fair value assuming 10% decrease in underlying commodity prices	*Asset*	68.2	33.0	61.8

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):

Scenario	Resulting Classification	Portfolio Fair Value at December 31, 2014	June 30, 2015	July 15, 2015
Fair value assuming no change in underlying commodity prices	*Asset (Liability)*	$ 15.6	$ (5.1)	$ 18.4
Fair value assuming 10% increase in underlying commodity prices	*Asset (Liability)*	6.5	(25.3)	0.9
Fair value assuming 10% decrease in underlying commodity prices	*Asset*	24.7	15.2	36.0

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 current principal executive officer), chief administrative officer, W. Randall Fowler, and chief financial officer, Bryan F. Bulawa, of the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 of the Securities Exchange Act of 1934. Mr. Fowler and Mr. Bulawa are our principal financial officers. Based on this evaluation, as of the end of the period covered by this quarterly report, Mr. Creel, Mr. Fowler and Mr. Bulawa 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
We are continuing to evaluate and implement changes to the processes, policies and other applicable components of our internal control over financial reporting due to the consolidation of Oiltanking's financial statements. Management continues to evaluate the effectiveness of our internal control procedures and the design of those control procedures as they relate to Oiltanking. In accordance with rules promulgated by the U.S. Securities and Exchange Commission, acquired businesses such as Oiltanking may be excluded from our assessment of internal control over financial reporting for one year while such businesses are being integrated with our legacy operations. We expect that this evaluation process will be completed during the fourth quarter of 2015.

We followed our normal accounting procedures and internal control processes when recording and disclosing the accounting impacts of the Oiltanking acquisition. In addition, management routinely reviews the results of operations of this acquired business prior to its consolidation with the results of operations of our other businesses.

There were no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the second quarter of 2015, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

The required certifications of Mr. Creel, Mr. Fowler and Mr. Bulawa 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*.

As part of our normal business activities, we may be named as defendants in litigation and legal proceedings, including those arising from regulatory and environmental matters. Although we are insured against various risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings. We will vigorously defend the partnership in litigation matters.

For additional information regarding our litigation matters, see "Litigation" under Note 15 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report, which subsection is incorporated by reference into this Part II, Item 1.

Item 1A. *Risk Factors.*

An investment in our securities involves certain risks. Security holders and potential investors in our securities should carefully consider the supplemental risk described below in addition to the risks described under "Risk Factors" set forth in Part I, Item 1A of our 2014 Form 10-K, in addition to other information in such annual report. The risk factors set forth in in this quarterly report and our 2014 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.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units, may be modified by administrative, legislative or judicial interpretation at any time. For example, from time to time, members of the U.S. Congress and the U.S. President propose and consider substantive changes to the existing U.S. federal income tax laws that affect the tax treatment of publicly traded partnerships.

Section 7704 of the Internal Revenue Code provides that a publicly traded partnership is treated as a corporation unless 90 percent or more of its income meets the "qualifying income requirement." On May 5, 2015, the U.S. Treasury Department and the Internal Revenue Service issued proposed regulations interpreting the scope of qualifying income for publicly traded partnerships by providing industry-specific guidance with respect to activities that will generate qualifying income for purposes of the qualifying income requirement. The proposed regulations, once issued in final form, may change interpretations of the current law relating to the characterization of income as qualifying income and could modify the amount of our gross income that we are able to treat as qualifying income for purposes of the qualifying income requirement.

Any modification to federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible for us to be treated as a partnership for federal income tax purposes (i.e., not taxed as a corporation). In addition, such changes may affect or cause us to change our business activities, affect the tax considerations of an investment in us, change the character or treatment of portions of our income, or otherwise adversely affect an investment in our common units. We are unable to predict whether any of these changes or any other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units and the amount of cash available for distribution to our unitholders.

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

The following table summarizes our repurchase activity during the six months ended June 30, 2015:

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 2015 (1)	628,750	$ 33.68	--	--
May 2015 (2)	33,492	$ 34.21	--	--

(1) Of the 1,852,746 restricted common units that vested in February 2015 and converted to common units, 628,750 units were sold back to us by employees to cover related withholding tax requirements.

(2) Of the 87,298 restricted common units that vested in May 2015 and converted to common units, 33,492 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.***

Disclosure Under Section 13(r) of the Securities Exchange Act of 1934

Under Section 13(r) of the Securities Exchange Act of 1934, as amended by the Iran Threat Reduction and Syria Human Rights Act of 2012, issuers are required to include certain disclosures in their periodic reports if they or any of their "affiliates" (as defined in Rule 12b-2 thereunder) have knowingly engaged in certain specified activities relating to Iran. Disclosure is required even where the activities are conducted outside the United States by non-U.S. affiliates in compliance with applicable law, and even if the activities are not covered or prohibited by U.S. law.

Dr. F. Christian Flach was named a director of our general partner in October 2014 in connection with the acquisition of Oiltanking. Dr. Flach is also a managing director of Oiltanking GmbH, which maintains a joint venture interest in Oiltanking Odfjell GmbH, which in turn owns a joint venture interest in the Exir Chemical Terminal ("ECT") in Iran. This interest results from an investment dating back to 2002. Oiltanking GmbH currently has the contractual right to vote for the appointment of one member of ECT's three-member board. Oiltanking GmbH provides no goods, services, technology, information or support to ECT and plays no role in the management or day-to-day operations of ECT.

Among other activities, ECT provides transit storage for naphtha originating in Iraq en route to Oman for a customer in the United Arab Emirates. ECT does not import or handle any products originated from Iran that are regulated under U.S., European Union or United Nations sanctions laws. ECT pays routine and standard charges (i) to the Petrochemical Special Economic Zone Organization ("Petzone") for the use of pipelines and (ii) to Terminals and Tanks Petrochemical Co. ("TTPC"), which operates the berth. Petzone and TTPC are subsidiaries of the National Petrochemical Company, which is owned and controlled by the Government of Iran. As Oiltanking GmbH has no direct involvement in the day-to-day operations of ECT, we have no information regarding ECT's intent to continue or not continue making the payments described above.

Oiltanking GmbH maintains an internal compliance program to ensure compliance with all applicable sanctions regimes, including sanctions laws maintained by the United States, European Union and United Nations. Although the existence of the routine payments described above may be reportable under Section 13(r), Oiltanking GmbH has informed us that neither it, nor any of its subsidiaries or affiliates, has engaged in any conduct that would be sanctionable under any of these legal regimes.

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).
2.12	Contribution and Purchase Agreement, dated as of October 1, 2014, by and among Enterprise Products Partners L.P., Oiltanking Holding Americas, Inc. and OTB Holdco, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed October 1, 2014).
2.13	Agreement and Plan of Merger, dated as of November 11, 2014, by and among Enterprise Products Partners L.P., Enterprise Products Holdings LLC, EPOT MergerCo LLC, Oiltanking Partners, L.P. and OTLP GP, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed November 12, 2014).
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	Amendment No. 2 to Sixth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated effective as of August 21, 2014 (incorporated by reference to Exhibit 3.1 to Form 8-K filed August 26, 2014).
3.6	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).

3.7	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).
3.8	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).
3.9	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).
3.10	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).
3.11	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	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).
4.4	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).
4.5	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).
4.6	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).
4.7	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).
4.8	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).
4.9	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).
4.10	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).
4.11	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).

4.12	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).
4.13	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).
4.14	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).
4.15	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).
4.16	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).
4.17	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).
4.18	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).
4.19	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).
4.20	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).
4.21	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).
4.22	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).
4.23	Twenty-Fifth Supplemental Indenture, dated as of February 12, 2014, 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 February 12, 2014).
4.24	Twenty-Sixth Supplemental Indenture, dated as of October 14, 2014, 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 4.4 to Form 8-K filed October 14, 2014).
4.25	Twenty-Seventh Supplemental Indenture, dated as of May 7, 2015, 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 7, 2015).

4.26	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).
4.27	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).
4.28	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).
4.29	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).
4.30	Form of Junior Subordinated Note, including Guarantee (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006).
4.31	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).
4.32	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).
4.33	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).
4.34	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).
4.35	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).
4.36	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).
4.37	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).
4.38	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).
4.39	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).
4.40	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).
4.41	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).
4.42	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).
4.43	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).
4.44	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).

4.45	Form of Global Note representing $750.0 million principal amount of 4.85% Senior Notes due 2042 with attached Guarantee (incorporated by reference to Exhibit 4.25 to Form 10-Q filed May 10, 2012).
4.46	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).
4.47	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).
4.48	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).
4.49	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).
4.50	Form of Global Note representing $850.0 million principal amount of 3.90% Senior Notes due 2024 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed February 12, 2014).
4.51	Form of Global Note representing $1.15 billion principal amount of 5.10% Senior Notes due 2045 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed February 12, 2014).
4.52	Form of Global Note representing $800.0 million principal amount of 2.55% Senior Notes due 2019 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 14, 2014).
4.53	Form of Global Note representing $1.15 billion principal amount of 3.75% Senior Notes due 2025 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 14, 2014).
4.54	Form of Global Note representing $400.0 million principal amount of 4.95% Senior Notes due 2054 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 14, 2014).
4.55	Form of Global Note representing $400.0 million principal amount of 4.85% Senior Notes due 2044 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 14, 2014).
4.56	Form of Global Note representing $750.0 million principal amount of 1.65% Senior Notes due 2018 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed May 7, 2015).
4.57	Form of Global Note representing $875.0 million principal amount of 3.70% Senior Notes due 2026 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed May 7, 2015).
4.58	Form of Global Note representing $875.0 million principal amount of 4.90% Senior Notes due 2046 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed May 7, 2015).
4.59	Replacement Capital Covenant, dated July 18, 2006, executed by Enterprise Products Operating L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 99.1 to Form 8-K filed July 19, 2006).
4.60	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).
4.61	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	Replacement Capital Covenant, dated October 27, 2009, executed by 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).

4.63	Amendment to Replacement Capital Covenants, dated May 6, 2015, executed by Enterprise Products Operating LLC and Enterprise Products Partners L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 4.59 to Form 10-Q filed May 8, 2015).
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	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).
4.66	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).
4.67	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).
4.68	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).
4.69	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).
4.70	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).
4.71	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).
4.72	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).
4.73	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).

4.74	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).
4.75	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).
4.76	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).
4.77	Registration Rights Agreement by and between Enterprise Products Partners L.P. and Oiltanking Holding Americas, Inc. dated as of October 1, 2014 (incorporated by reference to Exhibit 4.1 to Form 8-K filed on October 1, 2014).
12.1#	Computation of ratio of earnings to fixed charges for the six months ended June 30, 2015 and each of the years ended December 31, 2014, 2013, 2012, 2011 and 2010.
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 six months ended June 30, 2015.
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 six months ended June 30, 2015.
31.3#	Sarbanes-Oxley Section 302 certification of Bryan F. Bulawa for Enterprise Products Partners L.P.'s quarterly report on Form 10-Q for the six months ended June 30, 2015.
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 six months ended June 30, 2015.
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 six months ended June 30, 2015.
32.3#	Sarbanes-Oxley Section 906 certification of Bryan F. Bulawa for Enterprise Products Partners L.P.'s quarterly report on Form 10-Q for the six months ended June 30, 2015.
101.CAL#	XBRL Calculation Linkbase Document
101.DEF#	XBRL Definition Linkbase Document
101.INS#	XBRL Instance Document
101.LAB#	XBRL Labels Linkbase Document
101.PRE#	XBRL Presentation Linkbase Document
101.SCH#	XBRL Schema Document

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

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on August 7, 2015.

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

By: Enterprise Products Holdings LLC, as General Partner

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

EXHIBIT 12.1

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

	For the Six Months Ended June 30, 2015	For the Year Ended December 31,				
		2014	2013	2012	2011	2010
Consolidated income	$ 1,207.2	$ 2,833.5	$ 2,607.1	$ 2,428.0	$ 2,088.3	$ 1,383.7
Add: Provision for (benefit from) taxes	(1.1)	23.1	57.5	(17.2)	27.2	26.1
Less: Equity in earnings from unconsolidated affiliates	(199.4)	(259.5)	(167.3)	(64.3)	(46.4)	(62.0)
Consolidated pre-tax income before equity in earnings from unconsolidated affiliates	1,006.7	2,597.1	2,497.3	2,346.5	2,069.1	1,347.8
Add: Fixed charges	560.7	1,030.3	964.7	920.3	879.5	813.4
Amortization of capitalized interest	13.2	25.1	22.8	20.3	17.5	16.8
Distributed income of equity investees	265.5	375.1	251.6	116.7	156.4	191.9
Subtotal	1,846.1	4,027.6	3,736.4	3,403.8	3,122.5	2,369.9
Less: Capitalized interest	(65.3)	(77.9)	(133.0)	(116.8)	(106.7)	(47.2)
Net income attributable to noncontrolling interests	(20.1)	(46.1)	(10.2)	(8.1)	(20.5)	(25.5)
Total earnings	$ 1,760.7	$ 3,903.6	$ 3,593.2	$ 3,278.9	$ 2,995.3	$ 2,297.2
Fixed charges:						
Interest expense	$ 479.5	$ 921.0	$ 802.5	$ 771.8	$ 744.1	$ 741.9
Capitalized interest	65.3	77.9	133.0	116.8	106.7	47.2
Interest portion of rental expense	15.9	31.4	29.2	31.7	28.7	24.3
Total	$ 560.7	$ 1,030.3	$ 964.7	$ 920.3	$ 879.5	$ 813.4
Ratio of earnings to fixed charges	3.1x	3.8x	3.7x	3.6x	3.4x	2.8x

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 officers 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 officers 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: August 7, 2015

/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 officers 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 officers 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: August 7, 2015

/s/ W. Randall Fowler

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

EXHIBIT 31.3

SARBANES-OXLEY SECTION 302 CERTIFICATION

I, Bryan F. Bulawa, 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 officers 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 officers 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: August 7, 2015

/s/ Bryan F. Bulawa

Name: Bryan F. Bulawa
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 June 30, 2015 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.

Date: August 7, 2015

/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 32.2

SARBANES-OXLEY SECTION 906 CERTIFICATION

CERTIFICATION OF W. RANDALL FOWLER, CHIEF ADMINISTRATIVE 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 June 30, 2015 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, W. Randall Fowler, Chief Administrative 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.

Date: August 7, 2015

/s/ W. Randall Fowler

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

EXHIBIT 32.3

SARBANES-OXLEY SECTION 906 CERTIFICATION

CERTIFICATION OF BRYAN F. BULAWA, 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 June 30, 2015 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Bryan F. Bulawa, 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.

Date: August 7, 2015

/s/ Bryan F. Bulawa

Name: Bryan F. Bulawa
Title: Chief Financial Officer of Enterprise Products Holdings LLC, the General Partner of Enterprise Products Partners L.P.