

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

**FORM 10-Q**

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

For the quarterly period ended June 30, 2017

**OR**

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

For the transition period from \_\_\_ to \_\_\_.

Commission file number: 1-14323

**ENTERPRISE PRODUCTS PARTNERS L.P.**

(Exact Name of Registrant as Specified in Its Charter)

**Delaware**

(State or Other Jurisdiction of  
Incorporation or Organization)

**76-0568219**

(I.R.S. Employer Identification No.)

**1100 Louisiana Street, 10th Floor  
Houston, Texas 77002**

(Address of Principal Executive Offices, including Zip Code)

**(713) 381-6500**

(Registrant's Telephone Number, including Area Code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes  No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes  No

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

Large accelerated filer

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

Emerging growth company

Accelerated filer

Smaller reporting company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

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 2,148,986,109 common units of Enterprise Products Partners L.P. outstanding at the close of business on July 31, 2017. 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)

	<b>June 30, 2017</b>	<b>December 31, 2016</b>
<b>ASSETS</b>		
<b>Current assets:</b>		
Cash and cash equivalents	\$ 28.6	\$ 63.1
Restricted cash	35.4	354.5
Accounts receivable – trade, net of allowance for doubtful accounts of \$12.1 at June 30, 2017 and \$11.3 at December 31, 2016	2,655.7	3,329.5
Accounts receivable – related parties	3.0	1.1
Inventories	1,604.3	1,770.5
Derivative assets (see Note 12)	70.0	541.4
Prepaid and other current assets	387.5	468.1
Total current assets	4,784.5	6,528.2
<b>Property, plant and equipment, net</b>	34,220.7	33,292.5
<b>Investments in unconsolidated affiliates</b>	2,661.3	2,677.3
<b>Intangible assets, net of accumulated amortization of \$1,483.9 at   June 30, 2017 and \$1,403.1 at December 31, 2016</b> (see Note 6)	3,782.4	3,864.1
<b>Goodwill</b> (see Note 6)	5,745.2	5,745.2
<b>Other assets</b>	119.2	86.7
Total assets	\$ 51,313.3	\$ 52,194.0
<b>LIABILITIES AND EQUITY</b>		
<b>Current liabilities:</b>		
Current maturities of debt (see Note 7)	\$ 3,354.8	\$ 2,576.8
Accounts payable – trade	674.4	397.7
Accounts payable – related parties	62.9	105.1
Accrued product payables	2,951.1	3,613.7
Accrued interest	339.9	340.8
Derivative liabilities (see Note 12)	48.9	737.7
Other current liabilities	386.6	478.7
Total current liabilities	7,818.6	8,250.5
<b>Long-term debt</b> (see Note 7)	20,026.5	21,120.9
<b>Deferred tax liabilities</b>	53.4	52.7
<b>Other long-term liabilities</b>	534.6	503.9
<b>Commitments and contingencies</b> (see Note 14)		
<b>Equity:</b> (see Note 8)		
Partners' equity:		
Limited partners:		
Common units (2,148,035,389 units outstanding at June 30, 2017 and 2,117,588,414 units outstanding at December 31, 2016)	22,788.8	22,327.0
Accumulated other comprehensive loss	(128.7)	(280.0)
Total partners' equity	22,660.1	22,047.0
Noncontrolling interests	220.1	219.0
Total equity	22,880.2	22,266.0
Total liabilities and equity	\$ 51,313.3	\$ 52,194.0

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,	
	2017	2016	2017	2016
<b>Revenues:</b>				
Third parties	\$ 6,597.7	\$ 5,604.6	\$ 13,907.3	\$ 10,594.3
Related parties	9.9	13.2	20.7	28.8
Total revenues (see Note 9)	<u>6,607.6</u>	<u>5,617.8</u>	<u>13,928.0</u>	<u>10,623.1</u>
<b>Costs and expenses:</b>				
Operating costs and expenses:				
Third parties	5,457.6	4,551.9	11,539.2	8,418.2
Related parties	272.6	270.3	524.2	550.9
Total operating costs and expenses	<u>5,730.2</u>	<u>4,822.2</u>	<u>12,063.4</u>	<u>8,969.1</u>
General and administrative costs:				
Third parties	16.0	6.6	36.7	20.9
Related parties	29.7	28.5	59.4	58.1
Total general and administrative costs	<u>45.7</u>	<u>35.1</u>	<u>96.1</u>	<u>79.0</u>
Total costs and expenses (see Note 9)	<u>5,775.9</u>	<u>4,857.3</u>	<u>12,159.5</u>	<u>9,048.1</u>
<b>Equity in income of unconsolidated affiliates</b>	<u>107.0</u>	<u>76.4</u>	<u>201.8</u>	<u>177.5</u>
<b>Operating income</b>	<u>938.7</u>	<u>836.9</u>	<u>1,970.3</u>	<u>1,752.5</u>
<b>Other income (expense):</b>				
Interest expense	(245.8)	(244.1)	(495.1)	(484.7)
Change in fair market value of Liquidity Option Agreement (see Note 14)	(18.6)	(23.3)	(24.1)	(21.1)
Other, net	0.4	0.4	0.6	1.8
Total other expense, net	<u>(264.0)</u>	<u>(267.0)</u>	<u>(518.6)</u>	<u>(504.0)</u>
<b>Income before income taxes</b>	<u>674.7</u>	<u>569.9</u>	<u>1,451.7</u>	<u>1,248.5</u>
Benefit from (provision for) income taxes	(8.7)	0.1	(14.7)	(8.3)
<b>Net income</b>	<u>666.0</u>	<u>570.0</u>	<u>1,437.0</u>	<u>1,240.2</u>
Net income attributable to noncontrolling interests	(12.3)	(11.5)	(22.6)	(20.5)
<b>Net income attributable to limited partners</b>	<u>\$ 653.7</u>	<u>\$ 558.5</u>	<u>\$ 1,414.4</u>	<u>\$ 1,219.7</u>
<b>Earnings per unit:</b> (see Note 10)				
Basic earnings per unit	<u>\$ 0.30</u>	<u>\$ 0.27</u>	<u>\$ 0.66</u>	<u>\$ 0.59</u>
Diluted earnings per unit	<u>\$ 0.30</u>	<u>\$ 0.27</u>	<u>\$ 0.66</u>	<u>\$ 0.59</u>

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,	
	2017	2016	2017	2016
<b>Net income</b>	\$ 666.0	\$ 570.0	\$ 1,437.0	\$ 1,240.2
<b>Other comprehensive income (loss):</b>				
Cash flow hedges:				
Commodity derivative instruments:				
Changes in fair value of cash flow hedges	30.4	(73.7)	175.2	(74.9)
Reclassification of losses (gains) to net income	(46.0)	35.4	(38.9)	(21.8)
Interest rate derivative instruments:				
Changes in fair value of cash flow hedges	(6.9)	(9.4)	(4.5)	(9.4)
Reclassification of losses to net income	10.0	9.2	19.6	18.4
Total cash flow hedges	(12.5)	(38.5)	151.4	(87.7)
Other	--	--	(0.1)	(0.1)
Total other comprehensive income (loss)	(12.5)	(38.5)	151.3	(87.8)
<b>Comprehensive income</b>	653.5	531.5	1,588.3	1,152.4
Comprehensive income attributable to noncontrolling interests	(12.3)	(11.5)	(22.6)	(20.5)
<b>Comprehensive income attributable to limited partners</b>	<u>\$ 641.2</u>	<u>\$ 520.0</u>	<u>\$ 1,565.7</u>	<u>\$ 1,131.9</u>

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,	
	2017	2016
<b>Operating activities:</b>		
Net income	\$ 1,437.0	\$ 1,240.2
<i>Reconciliation of net income to net cash flows provided by operating activities:</i>		
Depreciation, amortization and accretion	808.8	763.4
Asset impairment and related charges (see Note 12)	25.2	22.3
Equity in income of unconsolidated affiliates	(201.8)	(177.5)
Distributions received on earnings from unconsolidated affiliates	205.1	195.1
Net losses attributable to asset sales	--	6.6
Deferred income tax expense	0.7	4.3
Change in fair market value of derivative instruments	(43.9)	68.3
Change in fair market value of Liquidity Option Agreement	24.1	21.1
Net effect of changes in operating accounts (see Note 15)	82.1	(294.6)
Other operating activities	(2.4)	(4.0)
Net cash flows provided by operating activities	<u>2,334.9</u>	<u>1,845.2</u>
<b>Investing activities:</b>		
Capital expenditures	(1,142.7)	(1,880.4)
Contributions in aid of construction costs	29.6	23.6
Decrease (increase) in restricted cash (see Note 2)	319.1	(356.7)
Cash used for Azure acquisition (see Note 4)	(191.4)	--
Investments in unconsolidated affiliates	(24.1)	(92.4)
Distributions received for return of capital from unconsolidated affiliates	24.8	39.4
Proceeds from asset sales	3.2	27.9
Other investing activities	2.0	--
Cash used in investing activities	<u>(979.5)</u>	<u>(2,238.6)</u>
<b>Financing activities:</b>		
Borrowings under debt agreements	33,307.8	33,235.3
Repayments of debt	(33,639.3)	(32,986.7)
Debt issuance costs	--	(9.7)
Cash distributions paid to limited partners (see Note 8)	(1,757.8)	(1,610.5)
Cash payments made in connection with distribution equivalent rights	(7.2)	(5.3)
Cash distributions paid to noncontrolling interests	(23.1)	(20.8)
Cash contributions from noncontrolling interests	0.3	16.0
Net cash proceeds from the issuance of common units	757.2	1,888.3
Other financing activities	(27.8)	(18.7)
Cash provided by (used in) financing activities	<u>(1,389.9)</u>	<u>487.9</u>
<b>Net change in cash and cash equivalents</b>	<u>(34.5)</u>	<u>94.5</u>
<b>Cash and cash equivalents, January 1</b>	63.1	19.0
<b>Cash and cash equivalents, June 30</b>	<u>\$ 28.6</u>	<u>\$ 113.5</u>

See Notes to Unaudited Condensed Consolidated Financial Statements.

**ENTERPRISE PRODUCTS PARTNERS L.P.**  
**UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED EQUITY**  
(See Note 8 for Unit History, Accumulated Other Comprehensive  
Income (Loss) and Noncontrolling Interests)  
(Dollars in millions)

	<b>Partners' Equity</b>			<b>Total</b>
	<b>Limited Partners</b>	<b>Accumulated Other Comprehensive Income (Loss)</b>	<b>Noncontrolling Interests</b>	
<b>Balance, January 1, 2017</b>	\$ 22,327.0	\$ (280.0)	\$ 219.0	\$ 22,266.0
Net income	1,414.4	--	22.6	1,437.0
Cash distributions paid to limited partners	(1,757.8)	--	--	(1,757.8)
Cash payments made in connection with distribution equivalent rights	(7.2)	--	--	(7.2)
Cash distributions paid to noncontrolling interests	--	--	(23.1)	(23.1)
Cash contributions from noncontrolling interests	--	--	0.3	0.3
Net cash proceeds from the issuance of common units	757.2	--	--	757.2
Common units issued in connection with employee compensation	33.7	--	--	33.7
Amortization of fair value of equity-based awards	49.8	--	--	49.8
Cash flow hedges	--	151.4	--	151.4
Other	(28.3)	(0.1)	1.3	(27.1)
<b>Balance, June 30, 2017</b>	<b>\$ 22,788.8</b>	<b>\$ (128.7)</b>	<b>\$ 220.1</b>	<b>\$ 22,880.2</b>

	<b>Partners' Equity</b>			<b>Total</b>
	<b>Limited Partners</b>	<b>Accumulated Other Comprehensive Income (Loss)</b>	<b>Noncontrolling Interests</b>	
<b>Balance, January 1, 2016</b>	\$ 20,514.3	\$ (219.2)	\$ 206.0	\$ 20,501.1
Net income	1,219.7	--	20.5	1,240.2
Cash distributions paid to limited partners	(1,610.5)	--	--	(1,610.5)
Cash payments made in connection with distribution equivalent rights	(5.3)	--	--	(5.3)
Cash distributions paid to noncontrolling interests	--	--	(20.8)	(20.8)
Cash contributions from noncontrolling interests	--	--	16.0	16.0
Net cash proceeds from the issuance of common units	1,888.3	--	--	1,888.3
Amortization of fair value of equity-based awards	45.6	--	--	45.6
Cash flow hedges	--	(87.7)	--	(87.7)
Other	(20.9)	(0.1)	--	(21.0)
<b>Balance, June 30, 2016</b>	<b>\$ 22,031.2</b>	<b>\$ (307.0)</b>	<b>\$ 221.7</b>	<b>\$ 21,945.9</b>

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 Directors (the “Board”) of Enterprise GP; (ii) Richard H. Bachmann, who is also a director and Vice Chairman of the Board of Enterprise GP; and (iii) Dr. Ralph S. Cunningham. Ms. Duncan Williams and Mr. Bachmann also currently serve as managers of Dan Duncan LLC along with W. Randall Fowler, who is also a director and President of Enterprise GP.

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. Duncan Williams, who serves as Chairman of EPCO; (ii) Dr. Cunningham, who serves as Vice Chairman of EPCO; and (iii) Mr. Bachmann, who serves as the President and Chief Executive Officer of EPCO. Ms. Duncan Williams and Mr. Bachmann also currently serve as directors of EPCO along with Mr. Fowler, who is also the Executive Vice President and Chief Administrative Officer of EPCO. EPCO, together with its privately held affiliates, owned approximately 32% of our limited partner interests at June 30, 2017.

References to “Oiltanking acquisition” mean the two-step acquisition of Oiltanking Partners, L.P. and its general partner that was completed in February 2015.

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

**Note 1. Partnership Operations, Organization and Basis of Presentation**

We are a publicly traded Delaware limited partnership, the common units of which are listed on the 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 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 the 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 export and import terminals (including those used to export liquefied petroleum gases, or “LPG,” and ethane); crude oil gathering, transportation, storage, and export and import terminals; petrochemical and refined products transportation, storage, export and import terminals, and related services; and a marine transportation business that operates primarily on the U.S. inland and Intracoastal Waterway systems. Our assets currently include approximately 50,000 miles of pipelines; 260 million barrels (“MMBbls”) of storage capacity for NGLs, crude oil, petrochemicals and refined products; and 14 billion cubic feet (“Bcf”) of natural gas storage capacity.



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

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.

Our operations are reported under four business segments: (i) NGL Pipelines & Services, (ii) Crude Oil Pipelines & Services, (iii) Natural Gas Pipelines & Services and (iv) Petrochemical & Refined Products Services. See Note 9 for information regarding our business segments.

**Note 2. General Accounting and Disclosure Matters**

Our results of operations for the six months ended June 30, 2017 are not necessarily indicative of results expected for the full year of 2017. 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, 2016 (the “2016 Form 10-K”) filed with the SEC on February 24, 2017.

***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 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.

Loss contingencies considered remote are generally not disclosed unless they involve guarantees, in which case the guarantees would be disclosed. See Note 14 for additional information regarding our contingencies.

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

***Derivative Instruments***

We use derivative instruments such as futures, swaps, forward contracts and other arrangements to manage price risks associated with inventories, firm commitments, interest rates 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 12 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.

***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.

**ENTERPRISE PRODUCTS PARTNERS L.P.**  
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***Recent Developments Involving Accounting for Revenues and Leases***

***Revenue Recognition.*** In May 2014, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Codification 606, *Revenues from Contracts with Customers* (“ASC 606”). The new accounting standard, along with its related amendments, replaces the current rules-based U.S. GAAP governing revenue recognition with a principles-based approach. We plan to adopt the new standard on January 1, 2018 using a modified retrospective approach, which requires us to apply the new revenue standard to (i) all new revenue contracts entered into after January 1, 2018 and (ii) all existing revenue contracts as of January 1, 2018 through a cumulative adjustment to equity. In accordance with this approach, our consolidated revenues for periods prior to January 1, 2018 will not be revised.

The core principle in the new guidance is that a company should recognize revenue in a manner that fairly depicts the transfer of goods or services to customers in amounts that reflect the consideration the company expects to receive for those goods or services. In order to apply this core principle, companies will apply the following five steps in determining the amount of revenues to recognize: (i) identify the contract; (ii) identify the performance obligations in the contract; (iii) determine the transaction price; (iv) allocate the transaction price to the performance obligations in the contract; and (v) recognize revenue when (or as) the performance obligation is satisfied. Each of these steps involves management’s judgment and an analysis of the contract’s material terms and conditions.

Our implementation activities related to ASC 606 are ongoing. For the vast majority of our businesses, we do not anticipate that there will be material differences in the amount or timing of revenues recognized following the new standard’s adoption date. However, we continue to evaluate the guidance under ASC 606 applicable to natural gas processing agreements where non-cash consideration is received for services rendered (e.g., equity NGL volumes received under percent of liquids, keepwhole and similar arrangements).

As a result of adopting the new standard, there will be significant changes to our disclosures based on the additional requirements prescribed by ASC 606. These new disclosures include information regarding the significant judgments used in evaluating when and how revenue is (or will be) recognized and data related to contract assets and liabilities. Additionally, we are currently evaluating our business processes, systems and controls to ensure the accuracy and timeliness of the recognition and disclosure requirements under the new revenue guidance.

***Leases.*** In February 2016, the FASB issued ASC 842, *Leases* (“ASC 842”), which requires substantially all leases (with the exception of leases with a term of one year or less) to be recorded on the balance sheet using a method referred to as the right-of-use (“ROU”) asset approach. We plan to adopt the new standard on January 1, 2019 using a modified retrospective approach.

The new standard introduces two lease accounting models, which result in a lease being classified as either a “finance” or “operating” lease on the basis of whether the lessee effectively obtains control of the underlying asset during the lease term. A lease would be classified as a finance lease if it meets one of five classification criteria, four of which are generally consistent with current lease accounting guidance. By default, a lease that does not meet the criteria to be classified as a finance lease will be deemed an operating lease. Regardless of classification, the initial measurement of both lease types will result in the balance sheet recognition of a ROU asset representing a company’s right to use the underlying asset for a specified period of time and a corresponding lease liability. The lease liability will be recognized at the present value of the future lease payments, and the ROU asset will equal the lease liability adjusted for any prepaid rent, lease incentives provided by the lessor, and any indirect costs.

The subsequent measurement of each type of lease varies. Leases classified as a finance lease will be accounted for using the effective interest method. Under this approach, a lessee will amortize the ROU asset (generally on a straight-line basis in a manner similar to depreciation) and the discount on the lease liability (as a component of interest expense). Leases classified as an operating lease will result in the recognition of a single lease expense amount that is recorded on a straight-line basis (or another systematic basis, if more appropriate).

We have started the process of reviewing our lease agreements in light of the new guidance. Although we are in the early stages of our ASC 842 implementation project, we anticipate that this new lease guidance will cause significant changes to the way leases are recorded, presented and disclosed in our consolidated financial statements.

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**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 margin requirements change.

At June 30, 2017 and December 31, 2016, our restricted cash amounts were \$35.4 million and \$354.5 million, respectively. The balance of restricted cash decreased since December 31, 2016 primarily due to the settlement of derivative instruments related to contango positions during 2017. See Note 12 for information regarding our derivative instruments and hedging activities.

*Impact of ASU 2016-18.* The FASB recently issued an amendment, ASU 2016-18, to Topic 230, *Statement of Cash Flows*, that standardizes the presentation of transfers to and from restricted cash within the cash flow statement. As a result, the cash flow statement will present changes in total cash amounts, regardless of whether the cash balances are restricted or unrestricted. The new guidance does not affect the separate presentation of restricted and unrestricted (i.e., cash and cash equivalents) amounts on the balance sheet. Furthermore, this change in financial statement presentation will not impact our consolidated liquidity.

We intend to adopt the new cash flow statement guidance on December 31, 2017 by retrospectively adjusting our consolidated cash flow statements to eliminate the presentation of cash inflows and outflows associated with restricted cash that were historically shown in the investing activities section.

**Note 3. Inventories**

Our inventory amounts by product type were as follows at the dates indicated:

	<b>June 30, 2017</b>	<b>December 31, 2016</b>
NGLs	\$ 897.1	\$ 1,156.1
Petrochemicals and refined products	377.4	220.7
Crude oil	313.2	360.0
Natural gas	16.6	33.7
Total	<u>\$ 1,604.3</u>	<u>\$ 1,770.5</u>

Due to fluctuating commodity prices, we recognize lower of cost or net realizable value 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 net realizable value adjustments for the periods indicated:

	<b>For the Three Months Ended June 30,</b>		<b>For the Six Months Ended June 30,</b>	
	<b>2017</b>	<b>2016</b>	<b>2017</b>	<b>2016</b>
Cost of sales (1)	\$ 4,731.1	\$ 3,838.7	\$ 10,066.8	\$ 7,047.0
Lower of cost or net realizable value adjustments within cost of sales	2.6	0.8	6.0	6.1

(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.

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**Note 4. 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:

	<b>Estimated Useful Life in Years</b>	<b>June 30, 2017</b>	<b>December 31, 2016</b>
Plants, pipelines and facilities (1)	3-45 (5)	\$ 35,785.9	\$ 35,124.6
Underground and other storage facilities (2)	5-40 (6)	3,388.4	3,326.9
Transportation equipment (3)	3-10	172.1	165.8
Marine vessels (4)	15-30	800.5	800.7
Land		266.8	264.6
Construction in progress		4,101.9	3,320.7
Total		44,515.6	43,003.3
Less accumulated depreciation		10,294.9	9,710.8
Property, plant and equipment, net		<u>\$ 34,220.7</u>	<u>\$ 33,292.5</u>

- (1) Plants, pipelines and facilities include processing plants; NGL, natural gas, crude oil and petrochemical and refined products pipelines; terminal loading and unloading facilities; buildings; office furniture and equipment; 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) Transportation equipment includes tractor-trailer tank trucks and other vehicles and similar assets used in our operations.
- (4) Marine vessels include tow boats, barges and related equipment used in our marine transportation business.
- (5) 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; buildings, 20-40 years; office furniture and equipment, 3-20 years; and laboratory and shop equipment, 5-35 years.
- (6) In general, the estimated useful lives of assets within this category are: underground storage facilities, 5-35 years; storage tanks, 10-40 years; and water wells, 5-35 years.

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

	<b>For the Three Months Ended June 30,</b>		<b>For the Six Months Ended June 30,</b>	
	<b>2017</b>	<b>2016</b>	<b>2017</b>	<b>2016</b>
Depreciation expense (1)	\$ 321.1	\$ 298.2	\$ 638.6	\$ 594.1
Capitalized interest (2)	44.5	46.4	84.1	88.9

- (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.

***Azure Acquisition***

In April 2017, we closed the acquisition of a midstream energy business from Azure Midstream Partners, LP and its operating subsidiaries (collectively, "Azure") for \$191.4 million in cash. The acquired business assets, which are located primarily in East Texas, include over 730 miles of natural gas gathering pipelines and two natural gas processing facilities with an aggregate processing capacity of 130 million cubic feet per day. The acquired business serves production from the Haynesville Shale and Bossier, Cotton Valley and Travis Peak formations.

The financial results of the acquired business are reflected in our consolidated results from April 30, 2017, which was the effective date of the Azure acquisition. On a historical pro forma consolidated basis, our revenues, costs and expenses, operating income, net income attributable to Enterprise Products Partners L.P., and earnings per unit amounts for the three and six months ended June 30, 2016 and 2017 would not have differed materially from those we actually reported had the Azure acquisition been completed on January 1, 2016 rather than April 30, 2017.

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The following table presents the preliminary fair value allocation of assets acquired and liabilities assumed in the Azure acquisition at April 30, 2017. The allocation remains provisional due to ongoing efforts to clarify certain environmental liabilities (estimated at \$2.2 million), which are expected to be resolved by December 31, 2017.

<b>Assets acquired in business combination:</b>	
Current assets	\$ 3.1
Property, plant and equipment	194.2
Total assets acquired	<u>197.3</u>
<b>Liabilities assumed in business combination:</b>	
Current liabilities	1.4
Long-term liabilities	4.5
Total liabilities assumed	<u>5.9</u>
Cash used for Azure acquisition	<u>\$ 191.4</u>

The contribution of this newly acquired business to our consolidated revenues and net income was not material for the second quarter of 2017.

***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 above-ground brine storage pits and 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, 2017 and December 31, 2016 includes \$40.3 million and \$44.9 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 January 1, 2017:

<b>ARO liability balance, January 1, 2017</b>	\$	\$ 85.4
Liabilities incurred		3.1
Liabilities settled		(1.5)
Revisions in estimated cash flows		(3.2)
Accretion expense		2.8
<b>ARO liability balance, June 30, 2017</b>	<u>\$</u>	<u>86.6</u>

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**Note 5. 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.

	<b>Ownership Interest at June 30, 2017</b>	<b>June 30, 2017</b>	<b>December 31, 2016</b>
<b>NGL Pipelines &amp; Services:</b>			
Venice Energy Service Company, L.L.C.	13.1%	\$ 25.9	\$ 24.8
K/D/S Promix, L.L.C.	50%	32.2	33.7
Baton Rouge Fractionators LLC	32.2%	17.6	17.3
Skelly-Belvieu Pipeline Company, L.L.C.	50%	37.1	38.9
Texas Express Pipeline LLC	35%	327.8	331.9
Texas Express Gathering LLC	45%	36.5	35.8
Front Range Pipeline LLC	33.3%	166.5	165.4
Delaware Basin Gas Processing LLC	50%	108.2	102.6
<b>Crude Oil Pipelines &amp; Services:</b>			
Seaway Crude Pipeline Company LLC	50%	1,380.5	1,393.8
Eagle Ford Pipeline LLC	50%	379.1	377.9
Eagle Ford Terminals Corpus Christi LLC	50%	63.2	52.9
<b>Natural Gas Pipelines &amp; Services:</b>			
White River Hub, LLC	50%	21.3	21.7
<b>Petrochemical &amp; Refined Products Services:</b>			
Centennial Pipeline LLC	50%	60.7	62.3
Other	Various	4.7	18.3
Total investments in unconsolidated affiliates		<u>\$ 2,661.3</u>	<u>\$ 2,677.3</u>

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

	<b>For the Three Months Ended June 30,</b>		<b>For the Six Months Ended June 30,</b>	
	<b>2017</b>	<b>2016</b>	<b>2017</b>	<b>2016</b>
NGL Pipelines & Services	\$ 19.0	\$ 14.0	\$ 34.5	\$ 29.1
Crude Oil Pipelines & Services	89.2	65.8	170.4	155.9
Natural Gas Pipelines & Services	0.9	0.9	1.9	1.9
Petrochemical & Refined Products Services	(2.1)	(4.3)	(5.0)	(9.4)
Total	<u>\$ 107.0</u>	<u>\$ 76.4</u>	<u>\$ 201.8</u>	<u>\$ 177.5</u>

***Excess Cost***

On occasion, the price we pay to acquire an ownership interest in a company exceeds the underlying carrying value of the capital accounts we acquire. These excess cost amounts are attributable to the fair value of the underlying tangible assets of these entities exceeding their respective book carrying values at the time of our acquisition of ownership interests in these entities. We amortize such excess cost amounts as a reduction to equity earnings in a manner similar to depreciation.

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

	<b>June 30, 2017</b>	<b>December 31, 2016</b>
NGL Pipelines & Services	\$ 23.5	\$ 24.1
Crude Oil Pipelines & Services	18.6	19.0
Petrochemical & Refined Products Services	1.9	2.1
Total	<u>\$ 44.0</u>	<u>\$ 45.2</u>

Amortization of excess cost amounts were \$0.5 million and \$0.6 million for the three months ended June 30, 2017 and 2016, respectively. For the six months ended June 30, 2017 and 2016, amortization of excess costs amounts were \$1.0 million and \$1.1 million, respectively.

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**Summarized Combined Financial Information of Unconsolidated Affiliates**

Combined results of operations data for the periods indicated for our unconsolidated affiliates are summarized in the following table (all data presented on a 100% basis):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2017	2016	2017	2016
<b>Income Statement Data:</b>				
Revenues	\$ 371.9	\$ 317.5	\$ 715.1	\$ 663.0
Operating income	229.8	181.7	433.5	395.4
Net income	237.6	178.3	440.5	393.5

**Note 6. Intangible Assets and Goodwill**

**Identifiable Intangible Assets**

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

	June 30, 2017			December 31, 2016		
	Gross Value	Accumulated Amortization	Carrying Value	Gross Value	Accumulated Amortization	Carrying Value
<b>NGL Pipelines &amp; Services:</b>						
Customer relationship intangibles	\$ 447.4	\$ (180.0)	\$ 267.4	\$ 447.4	\$ (172.7)	\$ 274.7
Contract-based intangibles	279.9	(211.7)	68.2	279.9	(204.4)	75.5
Segment total	727.3	(391.7)	335.6	727.3	(377.1)	350.2
<b>Crude Oil Pipelines &amp; Services:</b>						
Customer relationship intangibles	2,203.5	(104.4)	2,099.1	2,204.4	(84.5)	2,119.9
Contract-based intangibles	281.0	(146.5)	134.5	281.0	(121.9)	159.1
Segment total	2,484.5	(250.9)	2,233.6	2,485.4	(206.4)	2,279.0
<b>Natural Gas Pipelines &amp; Services:</b>						
Customer relationship intangibles	1,350.3	(402.5)	947.8	1,350.3	(390.0)	960.3
Contract-based intangibles	464.7	(375.0)	89.7	464.7	(370.5)	94.2
Segment total	1,815.0	(777.5)	1,037.5	1,815.0	(760.5)	1,054.5
<b>Petrochemical &amp; Refined Products Services:</b>						
Customer relationship intangibles	185.5	(46.9)	138.6	185.5	(43.9)	141.6
Contract-based intangibles	54.0	(16.9)	37.1	54.0	(15.2)	38.8
Segment total	239.5	(63.8)	175.7	239.5	(59.1)	180.4
Total intangible assets	\$ 5,266.3	\$ (1,483.9)	\$ 3,782.4	\$ 5,267.2	\$ (1,403.1)	\$ 3,864.1

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,	
	2017	2016	2017	2016
NGL Pipelines & Services	\$ 7.3	\$ 7.7	\$ 14.6	\$ 15.5
Crude Oil Pipelines & Services	22.3	24.7	45.4	52.4
Natural Gas Pipelines & Services	8.8	8.3	17.0	16.9
Petrochemical & Refined Products Services	2.3	2.3	4.7	4.5
Total	\$ 40.7	\$ 43.0	\$ 81.7	\$ 89.3



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

<b>Remainder of 2017</b>	<b>2018</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>
\$ 81.1	\$ 163.8	\$ 157.7	\$ 152.8	\$ 163.2

***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. There has been no change in our goodwill amounts since those reported in our 2016 Form 10-K.

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**Note 7. Debt Obligations**

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

	<b>June 30, 2017</b>	<b>December 31, 2016</b>
<b>EPO senior debt obligations:</b>		
Commercial Paper Notes, variable-rates	\$ 1,455.2	\$ 1,777.2
Senior Notes L, 6.30% fixed-rate, due September 2017	800.0	800.0
364-Day Credit Agreement, variable-rate, due September 2017	--	--
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	750.0
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
Multi-Year Revolving Credit Facility, variable-rate, due September 2020	--	--
Senior Notes RR, 2.85% fixed-rate, due April 2021	575.0	575.0
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	875.0
Senior Notes SS, 3.95% fixed-rate, due February 2027	575.0	575.0
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	975.0	975.0
Senior Notes NN, 4.95% fixed-rate, due October 2054	400.0	400.0
<b>TEPPCO senior debt obligations:</b>		
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	22,105.2	22,427.2
<b>EPO Junior Subordinated Notes A, variable-rate, due August 2066 (1)</b>	521.1	521.1
<b>EPO Junior Subordinated Notes C, fixed/variable-rate, due June 2067 (2)</b>	256.4	256.4
<b>EPO Junior Subordinated Notes B, fixed/variable-rate, due January 2068 (3)</b>	682.7	682.7
<b>TEPPCO Junior Subordinated Notes, fixed/variable-rate, due June 2067</b>	14.2	14.2
Total principal amount of senior and junior debt obligations	23,579.6	23,901.6
<b>Other, non-principal amounts</b>	(198.3)	(203.9)
Less current maturities of debt	(3,354.8)	(2,576.8)
Total long-term debt	<u>\$ 20,026.5</u>	<u>\$ 21,120.9</u>

- (1) Variable rate is reset quarterly and based on 3-month LIBOR plus 3.708%.
- (2) Fixed rate of 7.000% through May 31, 2017 (i.e., first call date without a make-whole redemption premium); thereafter, a variable rate reset quarterly and based on 3-month LIBOR plus 2.778%.
- (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 reset quarterly and based on 3-month LIBOR plus 2.680%.

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, 2017:

	<b>Range of Interest Rates Paid</b>	<b>Weighted-Average Interest Rate Paid</b>
Commercial Paper Notes	0.90% to 1.53%	1.20%
EPO Junior Subordinated Notes A	4.59% to 4.88%	4.76%
EPO Junior Subordinated Notes C	3.98%	3.98%

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The following table presents contractually scheduled maturities of our consolidated debt obligations outstanding at June 30, 2017 for the next five years, and in total thereafter:

	Scheduled Maturities of Debt						
	Total	Remainder of 2017	2018	2019	2020	2021	Thereafter
Commercial Paper Notes	\$ 1,455.2	\$ 1,455.2	\$ --	\$ --	\$ --	\$ --	\$ --
Senior Notes	20,650.0	800.0	1,100.0	1,500.0	1,500.0	575.0	15,175.0
Junior Subordinated Notes	1,474.4	--	--	--	--	--	1,474.4
Total	\$ 23,579.6	\$ 2,255.2	\$ 1,100.0	\$ 1,500.0	\$ 1,500.0	\$ 575.0	\$ 16,649.4

***Parent-Subsidiary Guarantor Relationships***

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

***Letters of Credit***

At June 30, 2017, EPO had \$66.4 million of letters of credit outstanding primarily related to our commodity hedging activities.

***Lender Financial Covenants***

We were in compliance with the financial covenants of our consolidated debt agreements at June 30, 2017.

**Note 8. Equity and Distributions**

***Partners' Equity***

Partners' equity reflects the various classes of limited partner interests (i.e., common units, including restricted common units) outstanding. The following table summarizes changes in the number of our outstanding units from January 1, 2017 to June 30, 2017:

	Common Units (Unrestricted)	Restricted Common Units	Total Common Units
<b>Number of units outstanding at January 1, 2017</b>	2,116,906,120	682,294	2,117,588,414
Common units issued in connection with ATM program	20,857,006	--	20,857,006
Common units issued in connection with DRIP and EUPP	7,035,681	--	7,035,681
Common units issued in connection with the vesting of phantom unit awards	2,351,436	--	2,351,436
Common units issued in connection with the vesting of restricted common unit awards	668,470	(668,470)	--
Forfeiture of restricted common unit awards	--	(1,250)	(1,250)
Cancellation of treasury units acquired in connection with the vesting of equity-based awards	(986,686)	--	(986,686)
Common units issued in connection with employee compensation	1,176,103	--	1,176,103
Other	14,685	--	14,685
<b>Number of units outstanding at June 30, 2017</b>	2,148,022,815	12,574	2,148,035,389

The net cash proceeds we received from the issuance of common units during the six months ended June 30, 2017 were used to temporarily reduce amounts outstanding under EPO's commercial paper program and revolving credit facilities and for general company purposes.

We expect to issue additional equity and debt securities to assist us in meeting our future liquidity requirements, including those related to capital spending.

Universal shelf registration statement. We have a universal shelf registration statement (the "2016 Shelf") on file with the SEC. The 2016 Shelf allows Enterprise Products Partners L.P. and EPO (each on a standalone basis) to issue an unlimited amount of equity and debt securities, respectively.

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At-the-Market (“ATM”) program. We have a registration statement on file with the SEC covering the issuance of up to \$1.89 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 in connection with our ATM program. Pursuant to this program, we may sell common units under an equity distribution agreement between Enterprise Products Partners L.P. and certain broker-dealers from time-to-time by means of ordinary brokers’ transactions through the NYSE at market prices, in block transactions or as otherwise agreed to with the broker-dealer parties to the agreement.

During the six months ended June 30, 2017, we sold 20,857,006 common units under the ATM program for aggregate gross proceeds of \$577.3 million. After taking into account applicable costs, our transactions under the ATM program resulted in aggregate net cash proceeds of \$571.8 million during the six months ended June 30, 2017.

During the six months ended June 30, 2016, we issued 68,645,180 common units under this program for aggregate gross cash proceeds of \$1.66 billion, resulting in total net cash proceeds of \$1.65 billion. This includes 3,830,256 common units sold in January 2016 to a privately held affiliate of EPCO, which generated gross proceeds of \$100 million.

After taking into account the aggregate sales price of common units sold under the ATM program through June 30, 2017, we have the capacity to issue additional common units under the ATM program up to an aggregate sales price of \$864.4 million.

Distribution reinvestment plan. We also have registration statements on file with the SEC collectively authorizing the issuance of up to 240,000,000 of our common units in connection with a distribution reinvestment plan (“DRIP”). The DRIP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of our common units they own by reinvesting the quarterly cash distributions they receive from us into the purchase of additional new common units.

We issued a total of 6,802,889 common units under our DRIP during the six months ended June 30, 2017, which generated net cash proceeds of \$179.0 million. During the six months ended June 30, 2016, we issued 10,104,741 common units under our DRIP, which generated net cash proceeds of \$232.3 million. Privately held affiliates of EPCO reinvested \$100 million through the DRIP during the six months ended June 30, 2016 (this amount being a component of the net cash proceeds presented).

After taking into account the number of common units issued under the DRIP through June 30, 2017, we have the capacity to issue an additional 92,455,606 common units under this plan.

Employee unit purchase 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 232,792 common units under our EUPP during the six months ended June 30, 2017, which generated net cash proceeds of \$6.4 million. During the six months ended June 30, 2016, we issued 279,960 common units under our EUPP, which generated net cash proceeds of \$6.8 million. After taking into account the number of common units issued under the EUPP through June 30, 2017, we may issue an additional 6,032,683 common units under this plan.

Common units issued in connection with employee compensation. In February 2017, the dollar value of the discretionary employee bonus payments with respect to the year ended December 31, 2016 (less any retirement plan deductions and withholding taxes) was remitted through the issuance of an equivalent value of newly issued Enterprise common units. The compensation expense associated with this issuance of common units was recognized during the year ended December 31, 2016.

***Noncontrolling Interests***

Noncontrolling interests represent third party equity ownership interests in our consolidated subsidiaries (e.g., joint venture partners in entities in which we have a controlling ownership interest).

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***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:

	<b>Gains (Losses) on Cash Flow Hedges</b>			
	<b>Commodity Derivative Instruments</b>	<b>Interest Rate Derivative Instruments</b>	<b>Other</b>	<b>Total</b>
<b>Balance, January 1, 2017</b>	\$ (83.8)	\$ (199.8)	\$ 3.6	\$ (280.0)
Other comprehensive income (loss) before reclassifications	175.2	(4.5)	(0.1)	170.6
Amounts reclassified from accumulated other comprehensive loss (income)	(38.9)	19.6	--	(19.3)
Total other comprehensive income (loss)	136.3	15.1	(0.1)	151.3
<b>Balance, June 30, 2017</b>	<b>\$ 52.5</b>	<b>\$ (184.7)</b>	<b>\$ 3.5</b>	<b>\$ (128.7)</b>

	<b>Gains (Losses) on Cash Flow Hedges</b>			
	<b>Commodity Derivative Instruments</b>	<b>Interest Rate Derivative Instruments</b>	<b>Other</b>	<b>Total</b>
<b>Balance, January 1, 2016</b>	\$ 56.6	\$ (279.5)	\$ 3.7	\$ (219.2)
Other comprehensive loss before reclassifications	(74.9)	(9.4)	(0.1)	(84.4)
Amounts reclassified from accumulated other comprehensive loss (income)	(21.8)	18.4	--	(3.4)
Total other comprehensive income (loss)	(96.7)	9.0	(0.1)	(87.8)
<b>Balance, June 30, 2016</b>	<b>\$ (40.1)</b>	<b>\$ (270.5)</b>	<b>\$ 3.6</b>	<b>\$ (307.0)</b>

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

<b>Location</b>	<b>For the Three Months Ended June 30,</b>		<b>For the Six Months Ended June 30,</b>	
	<b>2017</b>	<b>2016</b>	<b>2017</b>	<b>2016</b>
<b>Losses (gains) on cash flow hedges:</b>				
Interest rate derivatives	\$ 10.0	\$ 9.2	\$ 19.6	\$ 18.4
Commodity derivatives	(46.0)	34.2	(38.5)	(24.6)
Commodity derivatives	--	1.2	(0.4)	2.8
Total	<b>\$ (36.0)</b>	<b>\$ 44.6</b>	<b>\$ (19.3)</b>	<b>\$ (3.4)</b>

For information regarding our interest rate and commodity derivative instruments, see Note 12.

***Cash Distributions***

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

	<b>Distribution Per Common Unit</b>	<b>Record Date</b>	<b>Payment Date</b>
<b>2016</b>			
1st Quarter	\$ 0.3950	4/29/2016	5/6/2016
2nd Quarter	\$ 0.4000	7/29/2016	8/5/2016
<b>2017</b>			
1st Quarter	\$ 0.4150	4/28/2017	5/8/2017
2nd Quarter	\$ 0.4200	7/31/2017	8/7/2017

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**Note 9. Business Segments**

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

Our business segments are generally organized and managed according to the types of services rendered (or technologies employed) and products produced and/or sold. Financial information regarding these segments is evaluated regularly by our chief operating decision makers in deciding how to allocate resources and in assessing operating and financial performance.

**Segment Gross Operating Margin**

We evaluate segment performance based on our financial measure of gross operating margin. Gross operating margin is an important performance measure of the core profitability of our operations and forms the basis of our internal financial reporting. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. 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.

The following table presents our measurement of total segment gross operating margin for the periods presented. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income.

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2017	2016	2017	2016
Income before income taxes	\$ 674.7	\$ 569.9	\$ 1,451.7	\$ 1,248.5
Add total other expense, net	264.0	267.0	518.6	504.0
Operating income	938.7	836.9	1,970.3	1,752.5
<i>Adjustments to reconcile operating income to total gross operating margin:</i>				
Add depreciation, amortization and accretion expense in operating costs and expenses	379.2	360.3	755.4	718.5
Add asset impairment and related charges in operating costs and expenses	14.0	20.2	25.2	21.9
Add net losses attributable to asset sales in operating costs and expenses	0.3	1.7	--	6.6
Add general and administrative costs	45.7	35.1	96.1	79.0
<i>Adjustments for make-up rights on certain new pipeline projects:</i>				
Add non-refundable payments received from shippers attributable to make-up rights (1)	8.3	1.8	21.6	8.9
Subtract the subsequent recognition of revenues attributable to make-up rights (2)	(6.8)	(6.6)	(15.9)	(19.5)
Total segment gross operating margin	<u>\$ 1,379.4</u>	<u>\$ 1,249.4</u>	<u>\$ 2,852.7</u>	<u>\$ 2,567.9</u>

- (1) Since make-up rights entail a future performance obligation by the pipeline to the shipper, these receipts are recorded as deferred revenue for GAAP purposes; however, these receipts are included in gross operating margin in the period of receipt since they are nonrefundable to the shipper.
- (2) As deferred revenues attributable to make-up rights are subsequently recognized as revenue under GAAP, gross operating margin must be adjusted to remove such amounts to prevent duplication since the associated non-refundable payments were previously included in gross operating margin.

Gross operating margin by segment is calculated by subtracting segment operating costs and expenses from segment revenues, with both segment totals reflecting the adjustments noted in the preceding table, as applicable, and before the elimination of intercompany transactions. The following table presents gross operating margin by segment for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2017	2016	2017	2016
Gross operating margin by segment:				
NGL Pipelines & Services	\$ 759.9	\$ 719.1	\$ 1,615.9	\$ 1,502.8
Crude Oil Pipelines & Services	236.7	177.4	501.3	379.7
Natural Gas Pipelines & Services	194.4	177.4	365.3	355.1
Petrochemical & Refined Products Services	188.4	175.5	370.2	330.3
Total segment gross operating margin	<u>\$ 1,379.4</u>	<u>\$ 1,249.4</u>	<u>\$ 2,852.7</u>	<u>\$ 2,567.9</u>

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**Summarized Segment Financial Information**

Information by business segment, together with reconciliations to amounts presented on our Unaudited Condensed Statements of Consolidated Operations, is presented in the following table:

	Reportable Business Segments					Consolidated Total
	NGL Pipelines & Services	Crude Oil Pipelines & Services	Natural Gas Pipelines & Services	Petrochemical & Refined Products Services	Adjustments and Eliminations	
<b>Revenues from third parties:</b>						
Three months ended June 30, 2017	\$ 2,617.8	\$ 1,895.8	\$ 782.9	\$ 1,301.2	\$ --	\$ 6,597.7
Three months ended June 30, 2016	2,512.7	1,651.4	533.9	906.6	--	5,604.6
Six months ended June 30, 2017	5,960.8	3,698.4	1,540.7	2,707.4	--	13,907.3
Six months ended June 30, 2016	4,914.7	2,928.9	1,081.2	1,669.5	--	10,594.3
<b>Revenues from related parties:</b>						
Three months ended June 30, 2017	2.8	3.8	3.3	--	--	9.9
Three months ended June 30, 2016	2.8	8.6	1.8	--	--	13.2
Six months ended June 30, 2017	5.6	8.4	6.7	--	--	20.7
Six months ended June 30, 2016	4.6	19.7	4.5	--	--	28.8
<b>Intersegment and intrasegment revenues:</b>						
Three months ended June 30, 2017	5,642.1	3,383.7	220.6	389.7	(9,636.1)	--
Three months ended June 30, 2016	4,880.8	2,445.7	146.9	307.7	(7,781.1)	--
Six months ended June 30, 2017	14,516.9	6,857.7	415.1	804.4	(22,594.1)	--
Six months ended June 30, 2016	8,055.6	3,945.1	271.6	550.4	(12,822.7)	--
<b>Total revenues:</b>						
Three months ended June 30, 2017	8,262.7	5,283.3	1,006.8	1,690.9	(9,636.1)	6,607.6
Three months ended June 30, 2016	7,396.3	4,105.7	682.6	1,214.3	(7,781.1)	5,617.8
Six months ended June 30, 2017	20,483.3	10,564.5	1,962.5	3,511.8	(22,594.1)	13,928.0
Six months ended June 30, 2016	12,974.9	6,893.7	1,357.3	2,219.9	(12,822.7)	10,623.1
<b>Equity in income (loss) of unconsolidated affiliates:</b>						
Three months ended June 30, 2017	19.0	89.2	0.9	(2.1)	--	107.0
Three months ended June 30, 2016	14.0	65.8	0.9	(4.3)	--	76.4
Six months ended June 30, 2017	34.5	170.4	1.9	(5.0)	--	201.8
Six months ended June 30, 2016	29.1	155.9	1.9	(9.4)	--	177.5

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.

Information by business segment, together with reconciliations to our Unaudited Condensed Consolidated Balance Sheet totals, is presented in the following table:

	Reportable Business Segments					Consolidated Total
	NGL Pipelines & Services	Crude Oil Pipelines & Services	Natural Gas Pipelines & Services	Petrochemical & Refined Products Services	Adjustments and Eliminations	
<b>Property, plant and equipment, net:</b> (see Note 4)						
At June 30, 2017	\$ 14,125.8	\$ 4,355.1	\$ 8,297.2	\$ 3,340.7	\$ 4,101.9	\$ 34,220.7
At December 31, 2016	14,091.5	4,216.1	8,403.0	3,261.2	3,320.7	33,292.5
<b>Investments in unconsolidated affiliates:</b> (see Note 5)						
At June 30, 2017	751.8	1,822.8	21.3	65.4	--	2,661.3
At December 31, 2016	750.4	1,824.6	21.7	80.6	--	2,677.3
<b>Intangible assets, net:</b> (see Note 6)						
At June 30, 2017	335.6	2,233.6	1,037.5	175.7	--	3,782.4
At December 31, 2016	350.2	2,279.0	1,054.5	180.4	--	3,864.1
<b>Goodwill:</b> (see Note 6)						
At June 30, 2017	2,651.7	1,841.0	296.3	956.2	--	5,745.2
At December 31, 2016	2,651.7	1,841.0	296.3	956.2	--	5,745.2
<b>Segment assets:</b>						
At June 30, 2017	17,864.9	10,252.5	9,652.3	4,538.0	4,101.9	46,409.6
At December 31, 2016	17,843.8	10,160.7	9,775.5	4,478.4	3,320.7	45,579.1

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

***Other Revenue and Expense Information***

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,	
	2017	2016	2017	2016
<b>NGL Pipelines &amp; Services:</b>				
Sales of NGLs and related products	\$ 2,158.0	\$ 2,060.4	\$ 5,045.2	\$ 4,003.9
Midstream services	462.6	455.1	921.2	915.4
Total	<u>2,620.6</u>	<u>2,515.5</u>	<u>5,966.4</u>	<u>4,919.3</u>
<b>Crude Oil Pipelines &amp; Services:</b>				
Sales of crude oil	1,705.1	1,482.2	3,323.7	2,603.3
Midstream services	194.5	177.8	383.1	345.3
Total	<u>1,899.6</u>	<u>1,660.0</u>	<u>3,706.8</u>	<u>2,948.6</u>
<b>Natural Gas Pipelines &amp; Services:</b>				
Sales of natural gas	560.6	305.7	1,104.6	620.7
Midstream services	225.6	230.0	442.8	465.0
Total	<u>786.2</u>	<u>535.7</u>	<u>1,547.4</u>	<u>1,085.7</u>
<b>Petrochemical &amp; Refined Products Services:</b>				
Sales of petrochemicals and refined products	1,114.1	713.4	2,325.2	1,266.6
Midstream services	187.1	193.2	382.2	402.9
Total	<u>1,301.2</u>	<u>906.6</u>	<u>2,707.4</u>	<u>1,669.5</u>
<b>Total consolidated revenues</b>	<u>\$ 6,607.6</u>	<u>\$ 5,617.8</u>	<u>\$ 13,928.0</u>	<u>\$ 10,623.1</u>
<b>Consolidated costs and expenses</b>				
Operating costs and expenses:				
Cost of sales	\$ 4,731.1	\$ 3,838.7	\$ 10,066.8	\$ 7,047.0
Other operating costs and expenses (1)	605.6	601.3	1,216.0	1,175.1
Depreciation, amortization and accretion	379.2	360.3	755.4	718.5
Asset impairment and related charges	14.0	20.2	25.2	21.9
Net losses attributable to asset sales	0.3	1.7	--	6.6
General and administrative costs	45.7	35.1	96.1	79.0
<b>Total consolidated costs and expenses</b>	<u>\$ 5,775.9</u>	<u>\$ 4,857.3</u>	<u>\$ 12,159.5</u>	<u>\$ 9,048.1</u>

(1) Represents the cost of operating our plants, pipelines and other fixed assets excluding: depreciation, amortization and accretion charges; asset impairment and related charges; and net losses (or gains) attributable to asset sales.

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



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**Note 10. 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,	
	2017	2016	2017	2016
<b>BASIC EARNINGS PER UNIT</b>				
Net income attributable to limited partners	\$ 653.7	\$ 558.5	\$ 1,414.4	\$ 1,219.7
Undistributed earnings allocated and cash payments on phantom unit awards (1)	(4.0)	(3.3)	(8.0)	(6.5)
Net income available to common unitholders	<u>\$ 649.7</u>	<u>\$ 555.2</u>	<u>\$ 1,406.4</u>	<u>\$ 1,213.2</u>
Basic weighted-average number of common units outstanding	<u>2,144.7</u>	<u>2,085.1</u>	<u>2,135.5</u>	<u>2,059.3</u>
Basic earnings per unit	<u>\$ 0.30</u>	<u>\$ 0.27</u>	<u>\$ 0.66</u>	<u>\$ 0.59</u>
<b>DILUTED EARNINGS PER UNIT</b>				
Net income attributable to limited partners	<u>\$ 653.7</u>	<u>\$ 558.5</u>	<u>\$ 1,414.4</u>	<u>\$ 1,219.7</u>
Diluted weighted-average number of units outstanding:				
Distribution-bearing common units	2,144.7	2,085.1	2,135.5	2,059.3
Phantom units (1)	9.6	8.1	9.2	7.5
Total	<u>2,154.3</u>	<u>2,093.2</u>	<u>2,144.7</u>	<u>2,066.8</u>
Diluted earnings per unit	<u>\$ 0.30</u>	<u>\$ 0.27</u>	<u>\$ 0.66</u>	<u>\$ 0.59</u>

(1) Each phantom unit award includes a distribution equivalent right ("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.

**Note 11. 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,	
	2017	2016	2017	2016
<b>Equity-classified awards:</b>				
Phantom unit awards	\$ 23.5	\$ 19.3	\$ 46.3	\$ 38.7
Restricted common unit awards	--	0.7	0.5	2.9
Profits interest awards	1.6	1.6	3.1	2.3
<b>Liability-classified awards</b>	--	0.2	0.2	0.3
Total	<u>\$ 25.1</u>	<u>\$ 21.8</u>	<u>\$ 50.1</u>	<u>\$ 44.2</u>

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.

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At June 30, 2017, all of the outstanding phantom unit awards were granted under EPCO's 2008 Enterprise Products Long-Term Incentive Plan (Third Amendment and Restatement) ("2008 Plan"). The maximum number of common units authorized for issuance under the 2008 Plan was 40,000,000 at June 30, 2017. This amount will automatically increase under the terms of the 2008 Plan by 5,000,000 common units on January 1, 2018 and will continue to automatically increase annually on each 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 2008 Plan through June 30, 2017, a total of 18,947,916 additional common units were available for issuance under this plan.

EPCO serves as the general partner of four limited partnerships that were formed in 2016 (generally referred to as "Employee Partnerships") to serve as incentive arrangements for key employees of EPCO by providing them a "profits interest" in an Employee Partnership. The names of the Employee Partnerships are EPD PubCo Unit I L.P. ("PubCo I"), EPD PubCo Unit II L.P. ("PubCo II"), EPD PubCo Unit III L.P. ("PubCo III") and EPD PrivCo Unit I L.P. ("PrivCo I").

At June 30, 2017, a small number of restricted common unit awards remained outstanding under the Enterprise Products 1998 Long-Term Incentive Plan ("1998 Plan"). The 1998 Plan is effectively closed and no new awards have been granted under this plan since 2014.

***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, 2017, 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)
<b>Phantom unit awards at January 1, 2017</b>	7,767,501	\$ 27.20
Granted (2)	4,224,680	\$ 28.86
Vested	(2,355,937)	\$ 28.32
Forfeited	(107,145)	\$ 27.74
<b>Phantom unit awards at June 30, 2017</b>	<u>9,529,099</u>	<u>\$ 27.66</u>

(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 2017 was \$121.9 million based on a grant date market price of our common units ranging from \$26.40 to \$ 28.87 per unit. An estimated annual forfeiture rate of 3.8% was applied to these awards.

The 2008 Plan provides for the issuance of 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.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2017	2016	2017	2016
Cash payments made in connection with DERs	\$ 4.0	\$ 3.3	\$ 7.2	\$ 5.3
Total intrinsic value of phantom unit awards that vested during period	3.1	0.8	66.3	37.1

For the EPCO group of companies, the unrecognized compensation cost associated with phantom unit awards was \$142.0 million at June 30, 2017, of which our share of the cost is currently estimated to be \$122.5 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 2.2 years.

***Profits Interest Awards***

In 2016, EPCO Holdings Inc. (“EPCO Holdings”), a privately held affiliate of EPCO, contributed a portion of the Enterprise common units it owned to each of the Employee Partnerships. In exchange for these contributions, EPCO Holdings was admitted as the Class A limited partner of each Employee Partnership. Also on the applicable contribution date, certain key EPCO employees were issued Class B limited partner interests (i.e., profits interest awards) and admitted as Class B limited partners of each Employee Partnership, all without any capital contribution by such employees. EPCO serves as the general partner of each Employee Partnership.

The following table summarizes key elements of each Employee Partnership:

Employee Partnership	Enterprise Common Units owned by Employee Partnership	Class A Capital Base (1)	Class A Preference Return (2)	Expected Liquidation Date	Estimated Grant Date Fair Value of Profits Interest Awards (3)	Unrecognized Compensation Cost (4)
PubCo I	2,723,052 units	\$63.7 million	\$0.39	Feb. 2020	\$13.2 million	\$8.8 million
PubCo II	2,834,198 units	\$66.3 million	\$0.39	Feb. 2021	\$14.7 million	\$10.8 million
PubCo III	105,000 units	\$2.5 million	\$0.39	Apr. 2020	\$0.6 million	\$0.2 million
PrivCo I	1,111,438 units	\$26.0 million	\$0.39	Feb. 2021	\$5.8 million	\$0.9 million

- (1) Represents fair market value of the Enterprise common units contributed to each Employee Partnership at the applicable contribution date.
- (2) Each quarter, the Class A limited partner in each Employee Partnership is paid a cash distribution equal to the product of (i) the number of common units owned by the Employee Partnership and (ii) the Class A Preference Return of \$0.39 per unit (subject to equitable adjustment in order to reflect any equity split, equity distribution or dividend, reverse split, combination, reclassification, recapitalization or other similar event affecting such common units). To the extent that the Employee Partnership has cash remaining after making this quarterly payment to the Class A limited partner, the residual cash is distributed to the Class B limited partners on a quarterly basis.
- (3) Represents the total grant date fair value of the profits interest awards irrespective of how such costs will be allocated between us and EPCO and its privately held affiliates.
- (4) Represents our expected share of the unrecognized compensation cost at June 30, 2017. We expect to recognize our share of the unrecognized compensation cost for PubCo I, PubCo II, PubCo III and PrivCo I over a weighted-average period of 2.6 years, 3.6 years, 2.8 years and 3.6 years, respectively.

The grant date fair value of each Employee Partnership is based on (i) the estimated value (as determined using a Black-Scholes option pricing model) of such Employee Partnership’s assets that would be distributed to the Class B limited partners thereof upon liquidation and (ii) the value, based on a discounted cash flow analysis, of the residual quarterly cash amounts that such Class B limited partners are expected to receive over the life of the Employee Partnership.

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The following table summarizes the assumptions we used in applying a Black-Scholes option pricing model to derive that portion of the estimated grant date fair value of the profits interest awards for each Employee Partnership:

Employee Partnership	Expected Life of Award	Risk-Free Interest Rate	Expected Distribution Yield	Expected Unit Price Volatility
PubCo I	4.0 years	0.9% to 1.1%	6.2% to 6.8%	29% to 40%
PubCo II	5.0 years	1.1% to 1.7%	6.1% to 6.8%	27% to 40%
PubCo III	4.0 years	1.0% to 1.4%	6.1% to 6.2%	31% to 40%
PrivCo I	5.0 years	1.2% to 1.6%	6.1% to 6.7%	28% to 40%

Compensation expense attributable to the profits interest awards is based on the estimated grant date fair value of each award. A portion of the fair value of these equity-based awards is allocated to us under the ASA as a non-cash expense. We are not responsible for reimbursing EPCO for any expenses of the Employee Partnerships, including the value of any contributions of units made by EPCO Holdings.

***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 restricted common unit award activity for the period indicated:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
<b>Restricted common units at January 1, 2017</b>	682,294	\$ 28.61
Vested	(668,470)	\$ 28.56
Forfeited	(1,250)	\$ 31.07
<b>Restricted common units at June 30, 2017</b>	<u>12,574</u>	<u>\$ 30.92</u>

(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 restricted common unit awards for the periods indicated:

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2017	2016	2017	2016
Cash distributions paid to restricted common unitholders	\$ --	\$ 0.3	\$ 0.3	\$ 1.1
Total intrinsic value of restricted common unit awards that vested during period	0.1	0.5	18.6	27.3

We expect to recognize our share of the unrecognized compensation cost for these awards by the end of 2017.

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**Note 12. 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. This strategy may be used in controlling our overall cost of capital associated with such borrowings.

The following table summarizes our portfolio of interest rate swaps at June 30, 2017:

<b>Hedged Transaction</b>	<b>Number and Type of Derivatives Outstanding</b>	<b>Notional Amount</b>	<b>Period of Hedge</b>	<b>Rate Swap</b>	<b>Accounting Treatment</b>
Senior Notes OO	10 fixed-to-floating swaps	\$750.0	5/2015 to 5/2018	1.65% to 1.66%	Fair value hedge

The following table summarizes our portfolio of forward starting swaps at June 30, 2017:

<b>Hedged Transaction</b>	<b>Number and Type of Derivatives Outstanding</b>	<b>Notional Amount</b>	<b>Expected Settlement Date</b>	<b>Average Rate Locked</b>	<b>Accounting Treatment</b>
Future long-term debt offering	4 forward starting swaps	\$275.0	5/2018	2.02%	Cash flow hedge

***Commodity Hedging Activities***

The prices of natural gas, NGLs, crude oil, petrochemicals and refined 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 and basis swaps.

At June 30, 2017, 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 derivative instruments and related contracts.
- The objective of our natural gas processing hedging program is to hedge an amount of earnings associated with these activities. We achieve this objective by executing fixed-price sales for a portion of our expected equity NGL production using derivative instruments and related contracts. 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 using derivative instruments and related contracts.
- 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 derivative instruments and related contracts.

**ENTERPRISE PRODUCTS PARTNERS L.P.**  
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The following table summarizes our portfolio of commodity derivative instruments outstanding at June 30, 2017 (volume measures as noted):

Derivative Purpose	Volume (1)		Accounting Treatment
	Current (2)	Long-Term (2)	
<b><u>Derivatives designated as hedging instruments:</u></b>			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction (Bcf)	16.4	n/a	Cash flow hedge
Forecasted sales of NGLs (MMBbls)	2.3	n/a	Cash flow hedge
Natural gas marketing:			
Forecasted purchases of natural gas for fuel (Bcf)	3.0	n/a	Cash flow hedge
Natural gas storage inventory management activities (Bcf)	3.5	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	70.4	0.1	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	85.3	0.9	Cash flow hedge
NGLs inventory management activities (MMBbls)	1.4	n/a	Fair value hedge
Refined products marketing:			
Forecasted sales of refined products (MMBbls)	0.1	n/a	Cash flow hedge
Refined products inventory management activities (MMBbls)	4.8	n/a	Fair value hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	7.6	n/a	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	12.7	n/a	Cash flow hedge
<b><u>Derivatives not designated as hedging instruments:</u></b>			
Natural gas risk management activities (Bcf) (3,4)	169.2	20.4	Mark-to-market
NGL risk management activities (MMBbls) (4)	9.7	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (4)	35.3	17.5	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 2018, December 2017 and March 2020, respectively.
- (3) Current and long-term volumes include 61.0 Bcf and 9.3 Bcf, respectively, of physical derivative instruments that are predominantly priced at a marked-based index plus a premium or minus a discount related to location differences.
- (4) Reflects the use of derivative instruments to manage risks associated with transportation, processing and storage assets.

On January 3, 2017, the Chicago Mercantile Exchange (“CME”) modified its exchange rules to characterize daily variation margin amounts as “final settlement” values. The modified rule (“CME Rule 814”) impacts derivative financial instruments traded on exchanges administered by the CME, including the New York Mercantile Exchange. As a result of this rule change, we began reporting the affected derivative instruments on a net basis on our balance sheet during the first quarter of 2017. The netting process results in the elimination of derivative assets, derivative liabilities and associated restricted cash and related amounts with each other as if the underlying derivative instruments had settled on the balance sheet date. Historically through December 31, 2016, we reported such derivatives on a gross basis (i.e., not netted).

Derivative transactions cleared on exchanges other than the CME (e.g., the Intercontinental Exchange or ICE) continue to be reported on a gross basis.

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

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

	Asset Derivatives				Liability Derivatives			
	June 30, 2017		December 31, 2016		June 30, 2017		December 31, 2016	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
<b>Derivatives designated as hedging instruments</b>								
Interest rate derivatives	Current assets	\$ 31.7	Current assets	\$ 0.3	Current liabilities	\$ 1.6	Current liabilities	\$ 0.2
Interest rate derivatives	Other assets	--	Other assets	36.2	Other liabilities	--	Other liabilities	0.9
<b>Total interest rate derivatives</b>		<u>31.7</u>		<u>36.5</u>		<u>1.6</u>		<u>1.1</u>
Commodity derivatives	Current assets	35.2	Current assets	499.2	Current liabilities	37.0	Current liabilities	662.0
Commodity derivatives	Other assets	0.1	Other assets	--	Other liabilities	--	Other liabilities	--
<b>Total commodity derivatives</b>		<u>35.3</u>		<u>499.2</u>		<u>37.0</u>		<u>662.0</u>
<b>Total derivatives designated as hedging instruments</b>		<u>\$ 67.0</u>		<u>\$ 535.7</u>		<u>\$ 38.6</u>		<u>\$ 663.1</u>
<b>Derivatives not designated as hedging instruments</b>								
Commodity derivatives	Current assets	\$ 3.1	Current assets	\$ 41.9	Current liabilities	\$ 10.3	Current liabilities	\$ 75.6
Commodity derivatives	Other assets	2.5	Other assets	0.3	Other liabilities	1.6	Other liabilities	1.8
<b>Total commodity derivatives</b>		<u>\$ 5.6</u>		<u>\$ 42.2</u>		<u>\$ 11.9</u>		<u>\$ 77.4</u>

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

	Offsetting of Financial Assets and Derivative Assets						
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Amounts of Assets Presented in the Balance Sheet	Gross Amounts Not Offset in the Balance Sheet			Amounts That Would Have Been Presented On Net Basis
				Financial Instruments	Cash Collateral Received	Cash Collateral Paid	
(i)	(ii)	(iii) = (i) - (ii)	(iv)			(v) = (iii) + (iv)	
<b>As of June 30, 2017:</b>							
Interest rate derivatives	\$ 31.7	\$ --	\$ 31.7	\$ (0.5)	\$ --	\$ --	\$ 31.2
Commodity derivatives	40.9	--	40.9	(40.2)	--	--	0.7
<b>As of December 31, 2016:</b>							
Interest rate derivatives	\$ 36.5	\$ --	\$ 36.5	\$ (0.2)	\$ --	\$ --	\$ 36.3
Commodity derivatives	541.4	--	541.4	(526.8)	--	--	14.6

	Offsetting of Financial Liabilities and Derivative Liabilities						
	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Balance Sheet	Amounts of Liabilities Presented in the Balance Sheet	Gross Amounts Not Offset in the Balance Sheet			Amounts That Would Have Been Presented On Net Basis
				Financial Instruments	Cash Collateral Received	Cash Collateral Paid	
(i)	(ii)	(iii) = (i) - (ii)	(iv)			(v) = (iii) + (iv)	
<b>As of June 30, 2017:</b>							
Interest rate derivatives	\$ 1.6	\$ --	\$ 1.6	\$ (0.5)	\$ --	\$ --	\$ 1.1
Commodity derivatives	48.9	--	48.9	(40.2)	--	(7.7)	1.0
<b>As of December 31, 2016:</b>							
Interest rate derivatives	\$ 1.1	\$ --	\$ 1.1	\$ (0.2)	\$ --	\$ --	\$ 0.9
Commodity derivatives	739.4	--	739.4	(526.8)	--	(212.4)	0.2

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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,	
		2017	2016	2017	2016
Interest rate derivatives	Interest expense	\$ 0.4	\$ 1.2	\$ (0.5)	\$ 7.3
Commodity derivatives	Revenue	18.8	(63.0)	37.6	(82.0)
Total		\$ 19.2	\$ (61.8)	\$ 37.1	\$ (74.7)

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,	
		2017	2016	2017	2016
Interest rate derivatives	Interest expense	\$ (0.3)	\$ (1.3)	\$ 0.6	\$ (7.5)
Commodity derivatives	Revenue	(16.3)	51.0	(28.7)	79.0
Total		\$ (16.6)	\$ 49.7	\$ (28.1)	\$ 71.5

For the six months ended June 30, 2017, the net gain of \$8.9 million recognized in income from our commodity derivatives designated as fair value hedges includes \$0.8 million of net losses attributable to hedge ineffectiveness. The remaining \$9.7 million of net gain recognized during the six months ended June 30, 2017 was primarily related to prompt-to-forward month price differentials that were excluded from the assessment of hedge effectiveness. Net gains or losses due to ineffectiveness and from those amounts excluded from the assessment of hedge effectiveness were immaterial for all other 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,	
	2017	2016	2017	2016
Interest rate derivatives	\$ (6.9)	\$ (9.4)	\$ (4.5)	\$ (9.4)
Commodity derivatives – Revenue (1)	31.4	(80.5)	179.0	(77.2)
Commodity derivatives – Operating costs and expenses (1)	(1.0)	6.8	(3.8)	2.3
Total	\$ 23.5	\$ (83.1)	\$ 170.7	\$ (84.3)

- (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.



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<b>Derivatives in Cash Flow Hedging Relationships</b>	<b>Location</b>	<b>Gain (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) to Income (Effective Portion)</b>			
		<b>For the Three Months Ended June 30,</b>		<b>For the Six Months Ended June 30,</b>	
		<b>2017</b>	<b>2016</b>	<b>2017</b>	<b>2016</b>
Interest rate derivatives	Interest expense	\$ (10.0)	\$ (9.2)	\$ (19.6)	\$ (18.4)
Commodity derivatives	Revenue	46.0	(34.2)	38.5	24.6
Commodity derivatives	Operating costs and expenses	--	(1.2)	0.4	(2.8)
Total		<u>\$ 36.0</u>	<u>\$ (44.6)</u>	<u>\$ 19.3</u>	<u>\$ 3.4</u>

<b>Derivatives in Cash Flow Hedging Relationships</b>	<b>Location</b>	<b>Gain (Loss) Recognized in Income on Derivative (Ineffective Portion)</b>			
		<b>For the Three Months Ended June 30,</b>		<b>For the Six Months Ended June 30,</b>	
		<b>2017</b>	<b>2016</b>	<b>2017</b>	<b>2016</b>
Commodity derivatives	Operating costs and expenses	\$ (0.1)	\$ --	\$ (1.1)	\$ --
Total		<u>\$ (0.1)</u>	<u>\$ --</u>	<u>\$ (1.1)</u>	<u>\$ --</u>

Over the next twelve months, we expect to reclassify \$41.3 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 \$52.4 million of net gains attributable to commodity derivative instruments from accumulated other comprehensive income to earnings, \$52.6 million as an increase in revenue and \$0.2 million as an increase 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:

<b>Derivatives Not Designated as Hedging Instruments</b>	<b>Location</b>	<b>Gain (Loss) Recognized in Income on Derivative</b>			
		<b>For the Three Months Ended June 30,</b>		<b>For the Six Months Ended June 30,</b>	
		<b>2017</b>	<b>2016</b>	<b>2017</b>	<b>2016</b>
Commodity derivatives	Revenue	\$ 18.7	\$ (45.3)	\$ 34.4	\$ (46.6)
Commodity derivatives	Operating costs and expenses	(0.8)	(0.1)	3.7	--
Total		<u>\$ 17.9</u>	<u>\$ (45.4)</u>	<u>\$ 38.1</u>	<u>\$ (46.6)</u>

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**NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS**

***Fair Value Measurements***

The following tables set forth, by level within the Level 1, 2 and 3 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.

The values for commodity derivatives at June 30, 2017 are presented before and after the application of CME Rule 814, which deems that financial instruments cleared by the CME are settled daily in connection with variation margin payments. As a result of this new exchange rule, CME-related derivatives are considered to have no fair value at the balance sheet date for financial reporting purposes; however, the derivatives remain outstanding and subject to future commodity price fluctuations until they are settled in accordance with their contractual terms.

June 30, 2017				
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
<b>Financial assets:</b>				
Interest rate derivatives	\$ --	\$ 31.7	\$ --	\$ 31.7
Commodity derivatives:				
Value before application of CME Rule 814	29.5	147.9	0.5	177.9
Impact of CME Rule 814 change	(29.5)	(107.5)	--	(137.0)
Total commodity derivatives	--	40.4	0.5	40.9
Total financial assets	\$ --	\$ 72.1	\$ 0.5	\$ 72.6
<b>Financial liabilities:</b>				
Liquidity Option Agreement	\$ --	\$ --	\$ 293.7	\$ 293.7
Interest rate derivatives	--	1.6	--	1.6
Commodity derivatives:				
Value before application of CME Rule 814	9.8	134.2	0.3	144.3
Impact of CME Rule 814 change	(9.8)	(85.6)	--	(95.4)
Total commodity derivatives	--	48.6	0.3	48.9
Total financial liabilities	\$ --	\$ 50.2	\$ 294.0	\$ 344.2

December 31, 2016				
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
<b>Financial assets:</b>				
Interest rate derivatives	\$ --	\$ 36.5	\$ --	\$ 36.5
Commodity derivatives	84.5	455.2	1.7	541.4
Total financial assets	\$ 84.5	\$ 491.7	\$ 1.7	\$ 577.9
<b>Financial liabilities:</b>				
Liquidity Option Agreement	\$ --	\$ --	\$ 269.6	\$ 269.6
Interest rate derivatives	--	1.1	--	1.1
Commodity derivatives	136.8	602.3	0.3	739.4
Total financial liabilities	\$ 136.8	\$ 603.4	\$ 269.9	\$ 1,010.1

Our Level 3 financial liabilities at June 30, 2017 and December 31, 2016 primarily reflect the fair value assigned to the Liquidity Option Agreement (see Note 14) at each measurement date. The carrying value of the Liquidity Option Agreement (a long-term liability) was \$293.7 million and \$269.6 million at June 30, 2017 and December 31, 2016, respectively.

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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,	
		2017	2016
<b>Financial liability balance, net, January 1</b>		\$ (268.2)	\$ (246.7)
Total gains (losses) included in:			
Net income (1)	Revenue	0.7	0.7
Net income	Other expense, net	(5.5)	2.2
Other comprehensive income (loss)	Commodity derivative instruments – changes in fair value of cash flow hedges	--	1.5
Settlements	Revenue	(1.4)	(0.1)
Transfers out of Level 3		--	0.1
<b>Financial liability balance, net, March 31</b>		(274.4)	(242.3)
Total gains (losses) included in:			
Net income (1)	Revenue	0.1	--
Net income	Other expense, net	(18.6)	(23.3)
Other comprehensive income (loss)	Commodity derivative instruments – changes in fair value of cash flow hedges	0.1	2.0
Settlements	Revenue	(0.7)	(0.1)
Transfers out of Level 3		--	--
<b>Financial liability balance, net, June 30</b>		<u>\$ (293.5)</u>	<u>\$ (263.7)</u>

(1) There were unrealized losses of \$0.7 million and \$1.3 million included in these amounts for the three and six months ended June 30, 2017, respectively. There were unrealized losses of \$0.1 million and unrealized gains of \$0.5 million included in these amounts for the three and six months ended June 30, 2016, respectively.

The following table provides quantitative information regarding our recurring Level 3 fair value measurements for commodity derivatives at June 30, 2017:

	Fair Value		Valuation Techniques	Unobservable Input	Range
	Financial Assets	Financial Liabilities			
Commodity derivatives – Crude oil	\$ 0.3	\$ 0.2	Discounted cash flow	Forward commodity prices	\$44.84-\$47.60/barrel
Commodity derivatives – Ethane	0.2	0.1	Discounted cash flow	Forward commodity prices	\$0.26-\$0.32/gallon
Total	<u>\$ 0.5</u>	<u>\$ 0.3</u>			

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, 2017. 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.

**Nonrecurring Fair Value Measurements**

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2017	2016	2017	2016
NGL Pipelines & Services	\$ 2.8	\$ 2.1	\$ 3.0	\$ 2.4
Crude Oil Pipelines & Services	0.6	0.7	0.6	0.9
Natural Gas Pipelines & Services	9.7	9.7	9.9	9.7
Petrochemical & Refined Products Services	--	0.9	--	1.0
Total	<u>\$ 13.1</u>	<u>\$ 13.4</u>	<u>\$ 13.5</u>	<u>\$ 14.0</u>

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

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

The following table presents categories of long-lived assets that were subject to non-recurring fair value measurements during the six months ended June 30, 2017:

	<b>Fair Value Measurements at the End of the Reporting Period Using</b>				<b>Total Non-Cash Impairment Loss</b>
	<b>Quoted Prices in Active Markets for Identical Assets (Level 1)</b>	<b>Significant Other Observable Inputs (Level 2)</b>	<b>Significant Unobservable Inputs (Level 3)</b>		
<b>Carrying Value at June 30, 2017</b>					
Long-lived assets disposed of other than by sale	\$ --	\$ --	\$ --	\$ --	\$ 0.9
Long-lived assets held and used	1.4	--	--	1.4	3.1
Long-lived assets held for sale	1.2	--	--	1.2	9.5
Total					<u>\$ 13.5</u>

Total asset impairment and related charges during the six months ended June 30, 2017 were \$25.2 million, which consisted of \$13.5 million of impairment charges attributable to long-lived assets and \$11.7 million of impairment charges attributable to the write-down of spare parts classified as current assets.

The following table presents categories of long-lived assets that were subject to non-recurring fair value measurements during the six months ended June 30, 2016:

	<b>Fair Value Measurements at the End of the Reporting Period Using</b>				<b>Total Non-Cash Impairment Loss</b>
	<b>Quoted Prices in Active Markets for Identical Assets (Level 1)</b>	<b>Significant Other Observable Inputs (Level 2)</b>	<b>Significant Unobservable Inputs (Level 3)</b>		
<b>Carrying Value at June 30, 2016</b>					
Long-lived assets disposed of other than by sale	\$ --	\$ --	\$ --	\$ --	\$ 4.5
Long-lived assets held for sale	1.5	--	1.5	--	9.5
Total					<u>\$ 14.0</u>

Total asset impairment and related charges during the six months ended June 30, 2016 were \$22.3 million, which consisted of \$14.0 million of impairment charges attributable to long-lived assets, \$1.2 million of impairment charges attributable to the write-down of spare parts classified as current assets and \$7.1 million of related charges for equipment destroyed by fire at our Pascagoula gas plant.

***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 \$22.25 billion and \$21.95 billion at June 30, 2017 and December 31, 2016, respectively. The aggregate carrying value of these debt obligations was \$20.58 billion and \$20.85 billion at June 30, 2017 and December 31, 2016, 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 amounts reported for fixed-rate debt obligations exclude those amounts hedged using fixed-to-floating interest rate swaps. See “*Interest Rate Hedging Activities*” within this Note 12 for additional information. 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.

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

**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,	
	2017	2016	2017	2016
<b>Revenues – related parties:</b>				
Unconsolidated affiliates	\$ 9.9	\$ 13.2	\$ 20.7	\$ 28.8
<b>Costs and expenses – related parties:</b>				
EPCO and its privately held affiliates	\$ 247.4	\$ 241.4	\$ 490.5	\$ 478.7
Unconsolidated affiliates	54.9	57.4	93.1	130.3
Total	<u>\$ 302.3</u>	<u>\$ 298.8</u>	<u>\$ 583.6</u>	<u>\$ 609.0</u>

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

	June 30, 2017	December 31, 2016
<b>Accounts receivable - related parties:</b>		
Unconsolidated affiliates	\$ 3.0	\$ 1.1
<b>Accounts payable - related parties:</b>		
EPCO and its privately held affiliates	\$ 51.2	\$ 88.9
Unconsolidated affiliates	11.7	16.2
Total	<u>\$ 62.9</u>	<u>\$ 105.1</u>

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

***Relationship with EPCO and Affiliates***

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

At June 30, 2017, EPCO and its privately held affiliates (including Dan Duncan LLC and certain Duncan family trusts) beneficially owned the following limited partner interests in us:

Total Number of Units	Percentage of Total Units Outstanding
685,508,319	32%

Of the total number of units held by EPCO and its privately held affiliates, 118,000,000 have been pledged as security under the credit facilities of a privately held affiliate at June 30, 2017. In July 2017, the units pledged as security were reduced to 85,000,000 upon the completion of an amendment between EPCO and its privately held affiliates and the lenders. These credit facilities contain customary and other events of default, including defaults by us and other affiliates of EPCO. An event of default, followed by a foreclosure on the pledged collateral, could ultimately result in a change in ownership of these units and affect the market price of our common units.

We and Enterprise GP are both separate legal entities apart from each other and apart from EPCO and its other affiliates, with assets and liabilities that are also separate from those of EPCO and its other affiliates. EPCO and its privately held affiliates depend on the cash distributions they receive from us and other investments to fund their other activities and to meet their debt obligations. During the six months ended June 30, 2017 and 2016, we paid EPCO and its privately held affiliates cash distributions totaling \$553.7 million and \$525.2 million, respectively. 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.

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

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2017	2016	2017	2016
Operating costs and expenses	\$ 215.9	\$ 210.6	\$ 427.5	\$ 416.0
General and administrative expenses	27.1	26.3	53.9	53.6
Total costs and expenses	<u>\$ 243.0</u>	<u>\$ 236.9</u>	<u>\$ 481.4</u>	<u>\$ 469.6</u>

**Note 14. Commitments and Contingencies**

***Litigation***

As part of our normal business activities, we may be named as defendants in legal proceedings, including those arising from regulatory and environmental matters. Although we are insured against various risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to fully indemnify us against losses arising from future legal proceedings. 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, 2017 and December 31, 2016, our accruals for litigation contingencies were \$7.1 million and \$0.3 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.

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

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 trial court entered judgment against us in an aggregate amount of \$535.8 million, which included (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 trial court also awarded post-judgment interest on such aggregate amount, to accrue at a rate of 5%, compounded annually.

We filed our Brief of the Appellant in the Court of Appeals for the Fifth District of Dallas, Texas on March 30, 2015 and ETP filed its Brief of Appellees on June 29, 2015. We filed our Reply Brief of Appellant on September 18, 2015. Oral argument was conducted on April 20, 2016, and the case was then submitted to the Court of Appeals for its consideration. On July 18, 2017, a panel of the Court of Appeals issued a unanimous opinion reversing the trial court’s judgment as to all of ETP’s claims against Enterprise, rendering judgment that ETP take nothing on those claims, and affirming Enterprise’s counterclaim against ETP of approximately \$0.8 million, plus interest. We are grateful to the Dallas Court of Appeals for their hard work in this case and their reaffirmation of the importance of written contracts in business transactions. We continue to monitor developments involving this matter.

We have not recorded a provision for this matter as management believes payment of damages in this case by Enterprise is not probable.

*PDH Litigation.* In July 2013, we executed a contract with Foster Wheeler USA Corporation (“Foster Wheeler”) pursuant to which Foster Wheeler was to serve as the general contractor responsible for the engineering, procurement, construction and installation of our propane dehydrogenation (“PDH”) facility. In November 2014, Foster Wheeler was acquired by an affiliate of AMEC plc to form Amec Foster Wheeler plc, and Foster Wheeler is now known as Amec Foster Wheeler USA Corporation (“AFW”). In December 2015, Enterprise and AFW entered into a transition services agreement under which AFW was partially terminated from the PDH project. In December 2015, Enterprise engaged a second contractor, Optimized Process Designs LLC, to complete the construction and installation of the PDH facility.

On September 2, 2016, we terminated AFW for cause and filed a lawsuit in the 151st Judicial Civil District Court of Harris County, Texas against AFW and its parent company, Amec Foster Wheeler plc, asserting claims for breach of contract, breach of warranty, fraudulent inducement, string-along fraud, gross negligence, professional negligence, negligent misrepresentation and attorneys’ fees. We intend to diligently prosecute these claims and seek all direct, consequential, and exemplary damages to which we may be entitled.

***Contractual Obligations***

*Scheduled Maturities of Debt.* We have long-term and short-term payment obligations under debt agreements. See Note 7 for additional information regarding our scheduled future maturities of debt principal.

*Operating Lease Obligations.* Consolidated lease and rental expense was \$25.9 million and \$26.3 million during the three months ended June 30, 2017 and 2016, respectively. For the six months ended June 30, 2017 and 2016, consolidated lease and rental expense was \$52.1 million and \$54.8 million, respectively. Our operating lease commitments at June 30, 2017 did not differ materially from those reported in our 2016 Form 10-K.

*Purchase Obligations.* Our consolidated purchase obligations at June 30, 2017 did not differ materially from those reported in our 2016 Form 10-K.

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

***Liquidity Option Agreement***

We entered into a put option agreement (the “Liquidity Option Agreement” or “Liquidity Option”) with Oiltanking Holding Americas, Inc. (“OTA”) and Marquard & Bahls AG (“M&B”) in connection with the first step of the Oiltanking acquisition (“Step 1”). 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. If the Liquidity Option is exercised, we would indirectly acquire any Enterprise common units owned by OTA and assume all future income tax obligations of OTA associated with (i) owning common units encumbered by the entity-level taxes of a U.S. corporation and (ii) OTA’s deferred tax liabilities. To the extent that the sum of OTA’s deferred tax liabilities exceeds the then current book value of the Liquidity Option liability, we would recognize expense for the difference.

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 \$293.7 million and \$269.6 million at June 30, 2017 and December 31, 2016, respectively. The fair value of the Liquidity Option, at any measurement date, represents the present value of estimated federal and state income tax payments that we believe a market participant would incur on the future taxable income of OTA. 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 planning we believe could be employed. Our valuation estimate for the Liquidity Option at June 30, 2017 is based on several inputs that are not observable in the market (i.e., Level 3 inputs) such as the following:

- OTA remains in existence (i.e., is not dissolved and its assets sold) between one and 30 years following exercise of the Liquidity Option, depending on the liquidity preference of its owner. An equal probability that OTA would be dissolved was assigned to each year in the 30-year forecast period;
- OTA assumes approximately \$2.2 billion of associated long-term debt (30-year maturity) immediately after the Liquidity Option is exercised. For purposes of the valuation at June 30, 2017, we used a market rate commensurate with level of debt and tenure of approximately 4.5%. If the assumption of debt is excluded from the valuation model at June 30, 2017 (and all other inputs remained the same), the estimated fair value of the Liquidity Option would have increased by \$224.6 million and resulted in the recognition of an equal amount of expense at the time of change;
- Forecasted annual growth rates of Enterprise’s taxable earnings before interest, taxes, depreciation and amortization ranging from 0.1% to 13.6%;
- OTA’s ownership interest in Enterprise common units is assumed to be diluted over time in connection with Enterprise’s issuance of equity for general company reasons. For purposes of the valuation at June 30, 2017, we used ownership interests ranging from 1.9% to 2.5%;
- OTA pays an aggregate federal and state income tax rate of 38% on its taxable income; and
- A discount rate of 7.6% based on our weighted-average cost of capital at June 30, 2017.

Furthermore, our valuation estimate incorporates probability-weighted scenarios reflecting the likelihood that M&B may elect to divest a portion of the Enterprise common units held by OTA prior to exercise of the option. At June 30, 2017, based on these scenarios, we expect that OTA would own approximately 87% of the 54,807,352 Enterprise common units it received in Step 1 when the option period begins in February 2020. If our valuation estimate had assumed that OTA owned all of the Enterprise common units it received in Step 1 at the time of exercise (and all other inputs remained the same), the estimated fair value of the Liquidity Option liability at June 30, 2017 would have increased by \$45.1 million.

Changes in the fair value of the Liquidity Option are recognized in earnings as a component of other income (expense) on our Unaudited Condensed Statements of Consolidated Operations. Results for the three months ended June 30, 2017 and 2016 include \$18.6 million and \$23.3 million, respectively, of aggregate non-cash expense attributable to accretion and changes in management estimates regarding inputs to the valuation model. Results for the six months ended June 30, 2017 and 2016 include \$24.1 million and \$21.1 million, respectively, of such expense.



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

**Note 15. 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,	
	2017	2016
Decrease (increase) in:		
Accounts receivable – trade	\$ 602.7	\$ (481.8)
Accounts receivable – related parties	(1.9)	(0.6)
Inventories	234.3	(618.7)
Prepaid and other current assets	213.7	(51.3)
Other assets	(64.2)	0.5
Increase (decrease) in:		
Accounts payable – trade	46.6	(7.0)
Accounts payable – related parties	(8.4)	(5.3)
Accrued product payables	(694.2)	790.3
Accrued interest	(0.8)	(1.2)
Other current liabilities	(252.4)	74.6
Other liabilities	6.7	5.9
Net effect of changes in operating accounts	\$ 82.1	\$ (294.6)

We incurred liabilities for construction in progress that had not been paid at June 30, 2017 and December 31, 2016 of \$338.1 million and \$124.3 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.

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

**Note 16. 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 7 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, 2017**

	EPO and Subsidiaries				Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non- guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries			
<b>ASSETS</b>							
<b>Current assets:</b>							
Cash and cash equivalents and restricted cash	\$ 38.6	\$ 33.4	\$ (8.0)	\$ 64.0	\$ --	\$ --	\$ 64.0
Accounts receivable – trade, net	948.1	1,707.7	(0.1)	2,655.7	--	--	2,655.7
Accounts receivable – related parties	117.9	756.6	(863.2)	11.3	--	(8.3)	3.0
Inventories	1,240.6	364.1	(0.4)	1,604.3	--	--	1,604.3
Derivative assets	68.1	1.9	--	70.0	--	--	70.0
Prepaid and other current assets	210.7	203.5	(27.2)	387.0	0.5	--	387.5
Total current assets	2,624.0	3,067.2	(898.9)	4,792.3	0.5	(8.3)	4,784.5
<b>Property, plant and equipment, net</b>	5,212.8	29,006.3	1.6	34,220.7	--	--	34,220.7
<b>Investments in unconsolidated affiliates</b>	40,195.5	4,207.4	(41,741.6)	2,661.3	22,961.0	(22,961.0)	2,661.3
<b>Intangible assets, net</b>	692.2	3,104.3	(14.1)	3,782.4	--	--	3,782.4
<b>Goodwill</b>	459.5	5,285.7	--	5,745.2	--	--	5,745.2
<b>Other assets</b>	245.9	83.7	(211.0)	118.6	0.6	--	119.2
Total assets	\$ 49,429.9	\$ 44,754.6	\$ (42,864.0)	\$ 51,320.5	\$ 22,962.1	\$ (22,969.3)	\$ 51,313.3
<b>LIABILITIES AND EQUITY</b>							
<b>Current liabilities:</b>							
Current maturities of debt	\$ 3,354.4	\$ 0.4	\$ --	\$ 3,354.8	\$ --	\$ --	\$ 3,354.8
Accounts payable – trade	307.6	374.7	(7.9)	674.4	--	--	674.4
Accounts payable – related parties	845.1	96.8	(879.0)	62.9	8.3	(8.3)	62.9
Accrued product payables	1,466.3	1,486.5	(1.7)	2,951.1	--	--	2,951.1
Accrued interest	339.8	0.1	--	339.9	--	--	339.9
Derivative liabilities	43.7	5.2	--	48.9	--	--	48.9
Other current liabilities	83.5	325.9	(23.8)	385.6	--	1.0	386.6
Total current liabilities	6,440.4	2,289.6	(912.4)	7,817.6	8.3	(7.3)	7,818.6
<b>Long-term debt</b>	20,011.7	14.8	--	20,026.5	--	--	20,026.5
<b>Deferred tax liabilities</b>	4.7	45.5	(0.5)	49.7	--	3.7	53.4
<b>Other long-term liabilities</b>	57.1	397.1	(213.3)	240.9	293.7	--	534.6
<b>Commitments and contingencies</b>							
<b>Equity:</b>							
Partners' and other owners' equity	22,916.0	41,930.9	(41,911.0)	22,935.9	22,660.1	(22,935.9)	22,660.1
Noncontrolling interests	--	76.7	173.2	249.9	--	(29.8)	220.1
Total equity	22,916.0	42,007.6	(41,737.8)	23,185.8	22,660.1	(22,965.7)	22,880.2
Total liabilities and equity	\$ 49,429.9	\$ 44,754.6	\$ (42,864.0)	\$ 51,320.5	\$ 22,962.1	\$ (22,969.3)	\$ 51,313.3

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

**Enterprise Products Partners L.P.**  
**Unaudited Condensed Consolidating Balance Sheet**  
**December 31, 2016**

	EPO and Subsidiaries			Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non- guarantor)	EPO and Subsidiaries Eliminations and Adjustments				
<b>ASSETS</b>							
<b>Current assets:</b>							
Cash and cash equivalents and restricted cash	\$ 366.2	\$ 58.9	\$ (7.5)	\$ 417.6	\$ --	\$ --	\$ 417.6
Accounts receivable – trade, net	1,499.4	1,830.3	(0.2)	3,329.5	--	--	3,329.5
Accounts receivable – related parties	131.5	961.4	(1,090.7)	2.2	--	(1.1)	1.1
Inventories	1,357.5	413.5	(0.5)	1,770.5	--	--	1,770.5
Derivative assets	464.8	76.6	--	541.4	--	--	541.4
Prepaid and other current assets	290.7	191.1	(13.7)	468.1	--	--	468.1
Total current assets	4,110.1	3,531.8	(1,112.6)	6,529.3	--	(1.1)	6,528.2
<b>Property, plant and equipment, net</b>	4,796.5	28,495.7	0.3	33,292.5	--	--	33,292.5
<b>Investments in unconsolidated affiliates</b>	39,995.5	4,227.9	(41,546.1)	2,677.3	22,317.1	(22,317.1)	2,677.3
<b>Intangible assets, net</b>	700.2	3,178.2	(14.3)	3,864.1	--	--	3,864.1
<b>Goodwill</b>	459.5	5,285.7	--	5,745.2	--	--	5,745.2
<b>Other assets</b>	222.6	41.0	(177.5)	86.1	0.6	--	86.7
Total assets	\$ 50,284.4	\$ 44,760.3	\$ (42,850.2)	\$ 52,194.5	\$ 22,317.7	\$ (22,318.2)	\$ 52,194.0
<b>LIABILITIES AND EQUITY</b>							
<b>Current liabilities:</b>							
Current maturities of debt	\$ 2,576.7	\$ 0.1	\$ --	\$ 2,576.8	\$ --	\$ --	\$ 2,576.8
Accounts payable – trade	133.1	272.1	(7.5)	397.7	--	--	397.7
Accounts payable – related parties	1,071.5	139.6	(1,106.0)	105.1	1.1	(1.1)	105.1
Accrued product payables	1,944.5	1,670.3	(1.1)	3,613.7	--	--	3,613.7
Accrued interest	340.7	0.1	--	340.8	--	--	340.8
Derivative liabilities	590.3	147.4	--	737.7	--	--	737.7
Other current liabilities	173.5	316.5	(12.0)	478.0	--	0.7	478.7
Total current liabilities	6,830.3	2,546.1	(1,126.6)	8,249.8	1.1	(0.4)	8,250.5
<b>Long-term debt</b>	21,105.7	15.2	--	21,120.9	--	--	21,120.9
<b>Deferred tax liabilities</b>	5.0	45.1	(1.1)	49.0	--	3.7	52.7
<b>Other long-term liabilities</b>	13.5	400.6	(179.8)	234.3	269.6	--	503.9
<b>Commitments and contingencies</b>							
<b>Equity:</b>							
Partners' and other owners' equity	22,329.9	41,675.3	(41,713.4)	22,291.8	22,047.0	(22,291.8)	22,047.0
Noncontrolling interests	--	78.0	170.7	248.7	--	(29.7)	219.0
Total equity	22,329.9	41,753.3	(41,542.7)	22,540.5	22,047.0	(22,321.5)	22,266.0
Total liabilities and equity	\$ 50,284.4	\$ 44,760.3	\$ (42,850.2)	\$ 52,194.5	\$ 22,317.7	\$ (22,318.2)	\$ 52,194.0

**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, 2017**

	EPO and Subsidiaries			Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non- guarantor)	EPO and Subsidiaries Eliminations and Adjustments				
<b>Revenues</b>	\$ 8,541.0	\$ 4,274.4	\$ (6,207.8)	\$ 6,607.6	\$ --	\$ --	\$ 6,607.6
<b>Costs and expenses:</b>							
Operating costs and expenses	8,332.1	3,605.9	(6,207.8)	5,730.2	--	--	5,730.2
General and administrative costs	8.1	36.9	--	45.0	0.7	--	45.7
Total costs and expenses	8,340.2	3,642.8	(6,207.8)	5,775.2	0.7	--	5,775.9
<b>Equity in income of unconsolidated affiliates</b>	716.1	142.3	(751.4)	107.0	673.0	(673.0)	107.0
<b>Operating income</b>	916.9	773.9	(751.4)	939.4	672.3	(673.0)	938.7
<b>Other income (expense):</b>							
Interest expense	(243.8)	(4.3)	2.3	(245.8)	--	--	(245.8)
Other, net	2.3	0.4	(2.3)	0.4	(18.6)	--	(18.2)
Total other expense, net	(241.5)	(3.9)	--	(245.4)	(18.6)	--	(264.0)
<b>Income before income taxes</b>	675.4	770.0	(751.4)	694.0	653.7	(673.0)	674.7
Provision for income taxes	(3.3)	(5.0)	--	(8.3)	--	(0.4)	(8.7)
<b>Net income</b>	672.1	765.0	(751.4)	685.7	653.7	(673.4)	666.0
Net income attributable to noncontrolling interests	--	(1.6)	(12.0)	(13.6)	--	1.3	(12.3)
<b>Net income attributable to entity</b>	\$ 672.1	\$ 763.4	\$ (763.4)	\$ 672.1	\$ 653.7	\$ (672.1)	\$ 653.7

**Enterprise Products Partners L.P.**  
**Unaudited Condensed Consolidating Statement of Operations**  
**For the Three Months Ended June 30, 2016**

	EPO and Subsidiaries			Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non- guarantor)	EPO and Subsidiaries Eliminations and Adjustments				
<b>Revenues</b>	\$ 7,194.2	\$ 3,794.2	\$ (5,370.6)	\$ 5,617.8	\$ --	\$ --	\$ 5,617.8
<b>Costs and expenses:</b>							
Operating costs and expenses	7,002.0	3,190.9	(5,370.7)	4,822.2	--	--	4,822.2
General and administrative costs	4.1	30.5	--	34.6	0.5	--	35.1
Total costs and expenses	7,006.1	3,221.4	(5,370.7)	4,856.8	0.5	--	4,857.3
<b>Equity in income of unconsolidated affiliates</b>	637.3	126.4	(687.3)	76.4	582.3	(582.3)	76.4
<b>Operating income</b>	825.4	699.2	(687.2)	837.4	581.8	(582.3)	836.9
<b>Other income (expense):</b>							
Interest expense	(240.5)	(5.4)	1.8	(244.1)	--	--	(244.1)
Other, net	2.1	0.1	(1.8)	0.4	(23.3)	--	(22.9)
Total other expense, net	(238.4)	(5.3)	--	(243.7)	(23.3)	--	(267.0)
<b>Income before income taxes</b>	587.0	693.9	(687.2)	593.7	558.5	(582.3)	569.9
Benefit from income taxes	0.1	0.5	--	0.6	--	(0.5)	0.1
<b>Net income</b>	587.1	694.4	(687.2)	594.3	558.5	(582.8)	570.0
Net income attributable to noncontrolling interests	--	(2.3)	(10.6)	(12.9)	--	1.4	(11.5)
<b>Net income attributable to entity</b>	\$ 587.1	\$ 692.1	\$ (697.8)	\$ 581.4	\$ 558.5	\$ (581.4)	\$ 558.5

**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 Six Months Ended June 30, 2017**

	EPO and Subsidiaries			Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non- guarantor)	EPO and Subsidiaries Eliminations and Adjustments				
<b>Revenues</b>	\$ 21,073.8	\$ 8,582.6	\$ (15,728.4)	\$ 13,928.0	\$ --	\$ --	\$ 13,928.0
<b>Costs and expenses:</b>							
Operating costs and expenses	20,571.1	7,220.9	(15,728.6)	12,063.4	--	--	12,063.4
General and administrative costs	15.5	79.6	(0.2)	94.9	1.2	--	96.1
Total costs and expenses	20,586.6	7,300.5	(15,728.8)	12,158.3	1.2	--	12,159.5
<b>Equity in income of unconsolidated affiliates</b>	1,444.9	275.7	(1,518.8)	201.8	1,439.7	(1,439.7)	201.8
<b>Operating income</b>	1,932.1	1,557.8	(1,518.4)	1,971.5	1,438.5	(1,439.7)	1,970.3
<b>Other income (expense):</b>							
Interest expense	(492.6)	(7.0)	4.5	(495.1)	--	--	(495.1)
Other, net	4.5	0.6	(4.5)	0.6	(24.1)	--	(23.5)
Total other expense, net	(488.1)	(6.4)	--	(494.5)	(24.1)	--	(518.6)
<b>Income before income taxes</b>	1,444.0	1,551.4	(1,518.4)	1,477.0	1,414.4	(1,439.7)	1,451.7
Provision for income taxes	(6.2)	(7.6)	--	(13.8)	--	(0.9)	(14.7)
<b>Net income</b>	1,437.8	1,543.8	(1,518.4)	1,463.2	1,414.4	(1,440.6)	1,437.0
Net income attributable to noncontrolling interests	--	(3.3)	(21.9)	(25.2)	--	2.6	(22.6)
<b>Net income attributable to entity</b>	\$ 1,437.8	\$ 1,540.5	\$ (1,540.3)	\$ 1,438.0	\$ 1,414.4	\$ (1,438.0)	\$ 1,414.4

**Enterprise Products Partners L.P.**  
**Unaudited Condensed Consolidating Statement of Operations**  
**For the Six Months Ended June 30, 2016**

	EPO and Subsidiaries			Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non- guarantor)	EPO and Subsidiaries Eliminations and Adjustments				
<b>Revenues</b>	\$ 12,556.1	\$ 7,076.9	\$ (9,009.9)	\$ 10,623.1	\$ --	\$ --	\$ 10,623.1
<b>Costs and expenses:</b>							
Operating costs and expenses	12,093.2	5,886.0	(9,010.1)	8,969.1	--	--	8,969.1
General and administrative costs	10.1	67.3	--	77.4	1.6	--	79.0
Total costs and expenses	12,103.3	5,953.3	(9,010.1)	9,046.5	1.6	--	9,048.1
<b>Equity in income of unconsolidated affiliates</b>	1,270.0	260.0	(1,352.5)	177.5	1,242.4	(1,242.4)	177.5
<b>Operating income</b>	1,722.8	1,383.6	(1,352.3)	1,754.1	1,240.8	(1,242.4)	1,752.5
<b>Other income (expense):</b>							
Interest expense	(477.6)	(10.6)	3.5	(484.7)	--	--	(484.7)
Other, net	3.9	1.4	(3.5)	1.8	(21.1)	--	(19.3)
Total other expense, net	(473.7)	(9.2)	--	(482.9)	(21.1)	--	(504.0)
<b>Income before income taxes</b>	1,249.1	1,374.4	(1,352.3)	1,271.2	1,219.7	(1,242.4)	1,248.5
Provision for income taxes	(2.8)	(4.6)	--	(7.4)	--	(0.9)	(8.3)
<b>Net income</b>	1,246.3	1,369.8	(1,352.3)	1,263.8	1,219.7	(1,243.3)	1,240.2
Net income attributable to noncontrolling interests	--	(3.6)	(19.5)	(23.1)	--	2.6	(20.5)
<b>Net income attributable to entity</b>	\$ 1,246.3	\$ 1,366.2	\$ (1,371.8)	\$ 1,240.7	\$ 1,219.7	\$ (1,240.7)	\$ 1,219.7

**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 Three Months Ended June 30, 2017**

	EPO and Subsidiaries			Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non- guarantor)	EPO and Subsidiaries Eliminations and Adjustments				
<b>Comprehensive income</b>	\$ 661.3	\$ 763.2	\$ (751.4)	\$ 673.1	\$ 641.2	\$ (660.8)	\$ 653.5
Comprehensive income attributable to noncontrolling interests	--	(1.6)	(12.0)	(13.6)	--	1.3	(12.3)
<b>Comprehensive income attributable to entity</b>	<u>\$ 661.3</u>	<u>\$ 761.6</u>	<u>\$ (763.4)</u>	<u>\$ 659.5</u>	<u>\$ 641.2</u>	<u>\$ (659.5)</u>	<u>\$ 641.2</u>

**Enterprise Products Partners L.P.**  
**Unaudited Condensed Consolidating Statement of Comprehensive Income**  
**For the Three Months Ended June 30, 2016**

	EPO and Subsidiaries			Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non- guarantor)	EPO and Subsidiaries Eliminations and Adjustments				
<b>Comprehensive income</b>	\$ 519.4	\$ 723.5	\$ (687.2)	\$ 555.7	\$ 520.0	\$ (544.2)	\$ 531.5
Comprehensive income attributable to noncontrolling interests	--	(2.3)	(10.6)	(12.9)	--	1.4	(11.5)
<b>Comprehensive income attributable to entity</b>	<u>\$ 519.4</u>	<u>\$ 721.2</u>	<u>\$ (697.8)</u>	<u>\$ 542.8</u>	<u>\$ 520.0</u>	<u>\$ (542.8)</u>	<u>\$ 520.0</u>

**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, 2017**

	EPO and Subsidiaries				Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non- guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries			
<b>Comprehensive income</b>	\$ 1,531.4	\$ 1,601.5	\$ (1,518.4)	\$ 1,614.5	\$ 1,565.7	\$ (1,591.9)	\$ 1,588.3
Comprehensive income attributable to noncontrolling interests	--	(3.3)	(21.9)	(25.2)	--	2.6	(22.6)
<b>Comprehensive income attributable to entity</b>	<u>\$ 1,531.4</u>	<u>\$ 1,598.2</u>	<u>\$ (1,540.3)</u>	<u>\$ 1,589.3</u>	<u>\$ 1,565.7</u>	<u>\$ (1,589.3)</u>	<u>\$ 1,565.7</u>

**Enterprise Products Partners L.P.**  
**Unaudited Condensed Consolidating Statement of Comprehensive Income**  
**For the Six Months Ended June 30, 2016**

	EPO and Subsidiaries				Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non- guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries			
<b>Comprehensive income</b>	\$ 1,174.6	\$ 1,353.6	\$ (1,352.2)	\$ 1,176.0	\$ 1,131.9	\$ (1,155.5)	\$ 1,152.4
Comprehensive income attributable to noncontrolling interests	--	(3.6)	(19.5)	(23.1)	--	2.6	(20.5)
<b>Comprehensive income attributable to entity</b>	<u>\$ 1,174.6</u>	<u>\$ 1,350.0</u>	<u>\$ (1,371.7)</u>	<u>\$ 1,152.9</u>	<u>\$ 1,131.9</u>	<u>\$ (1,152.9)</u>	<u>\$ 1,131.9</u>

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

**Enterprise Products Partners L.P.**  
**Unaudited Condensed Consolidating Statement of Cash Flows**  
**For the Six Months Ended June 30, 2017**

	EPO and Subsidiaries			Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non- guarantor)	EPO and Subsidiaries Eliminations and Adjustments				
<b>Operating activities:</b>							
Net income	\$ 1,437.8	\$ 1,543.8	\$ (1,518.4)	\$ 1,463.2	\$ 1,414.4	\$ (1,440.6)	\$ 1,437.0
<i>Reconciliation of net income to net cash flows provided by operating activities:</i>							
Depreciation, amortization and accretion	103.3	705.7	(0.2)	808.8	--	--	808.8
Equity in income of unconsolidated affiliates	(1,444.9)	(275.7)	1,518.8	(201.8)	(1,439.7)	1,439.7	(201.8)
Distributions received on earnings from unconsolidated affiliates	529.3	133.7	(457.9)	205.1	1,753.3	(1,753.3)	205.1
Net effect of changes in operating accounts and other operating activities	1,793.0	(1,766.2)	(0.7)	26.1	59.3	0.4	85.8
Net cash flows provided by operating activities	2,418.5	341.3	(458.4)	2,301.4	1,787.3	(1,753.8)	2,334.9
<b>Investing activities:</b>							
Capital expenditures, net of contributions in aid of construction costs	(369.3)	(743.8)	--	(1,113.1)	--	--	(1,113.1)
Cash used for business combination, net of cash received	--	(191.4)	--	(191.4)	--	--	(191.4)
Proceeds from asset sales	1.4	1.8	--	3.2	--	--	3.2
Other investing activities	(759.8)	(26.7)	1,108.3	321.8	(750.9)	750.9	321.8
Cash used in investing activities	(1,127.7)	(960.1)	1,108.3	(979.5)	(750.9)	750.9	(979.5)
<b>Financing activities:</b>							
Borrowings under debt agreements	33,307.8	--	--	33,307.8	--	--	33,307.8
Repayments of debt	(33,605.2)	(0.1)	(34.0)	(33,639.3)	--	--	(33,639.3)
Cash distributions paid to owners	(1,753.3)	(491.2)	491.2	(1,753.3)	(1,757.8)	1,753.3	(1,757.8)
Cash payments made in connection with DERs	--	--	--	--	(7.2)	--	(7.2)
Cash distributions paid to noncontrolling interests	--	(4.7)	(18.9)	(23.6)	--	0.5	(23.1)
Cash contributions from noncontrolling interests	--	0.1	0.2	0.3	--	--	0.3
Net cash proceeds from issuance of common units	--	--	--	--	757.2	--	757.2
Cash contributions from owners	750.9	1,088.9	(1,088.9)	750.9	--	(750.9)	--
Other financing activities	0.7	--	--	0.7	(28.5)	--	(27.8)
Cash provided by (used in) financing activities	(1,299.1)	593.0	(650.4)	(1,356.5)	(1,036.3)	1,002.9	(1,389.9)
<b>Net change in cash and cash equivalents</b>	(8.3)	(25.8)	(0.5)	(34.6)	0.1	--	(34.5)
<b>Cash and cash equivalents, January 1</b>	13.4	57.2	(7.5)	63.1	--	--	63.1
<b>Cash and cash equivalents, June 30</b>	\$ 5.1	\$ 31.4	\$ (8.0)	\$ 28.5	\$ 0.1	\$ --	\$ 28.6



**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, 2016**

	EPO and Subsidiaries			Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non- guarantor)	EPO and Subsidiaries Eliminations and Adjustments				
<b>Operating activities:</b>							
Net income	\$ 1,246.3	\$ 1,369.8	\$ (1,352.3)	\$ 1,263.8	\$ 1,219.7	\$ (1,243.3)	\$ 1,240.2
<i>Reconciliation of net income to net cash flows provided by operating activities:</i>							
Depreciation, amortization and accretion	84.9	678.7	(0.2)	763.4	--	--	763.4
Equity in income of unconsolidated affiliates	(1,270.0)	(260.0)	1,352.5	(177.5)	(1,242.4)	1,242.4	(177.5)
Distributions received on earnings from unconsolidated affiliates	475.9	81.5	(362.3)	195.1	1,633.4	(1,633.4)	195.1
Net effect of changes in operating accounts and other operating activities	679.7	(922.9)	46.8	(196.4)	19.8	0.6	(176.0)
Net cash flows provided by operating activities	1,216.8	947.1	(315.5)	1,848.4	1,630.5	(1,633.7)	1,845.2
<b>Investing activities:</b>							
Capital expenditures, net of contributions in aid of construction costs	(729.1)	(1,127.7)	--	(1,856.8)	--	--	(1,856.8)
Proceeds from asset sales	13.9	14.0	--	27.9	--	--	27.9
Other investing activities	(945.0)	(47.5)	582.8	(409.7)	(1,881.8)	1,881.8	(409.7)
Cash used in investing activities	(1,660.2)	(1,161.2)	582.8	(2,238.6)	(1,881.8)	1,881.8	(2,238.6)
<b>Financing activities:</b>							
Borrowings under debt agreements	33,235.3	32.5	(32.5)	33,235.3	--	--	33,235.3
Repayments of debt	(32,986.6)	(0.1)	--	(32,986.7)	--	--	(32,986.7)
Cash distributions paid to owners	(1,633.4)	(379.9)	379.9	(1,633.4)	(1,610.5)	1,633.4	(1,610.5)
Cash payments made in connection with DERs	--	--	--	--	(5.3)	--	(5.3)
Cash distributions paid to noncontrolling interests	--	(3.5)	(17.6)	(21.1)	--	0.3	(20.8)
Cash contributions from noncontrolling interests	--	16.0	--	16.0	--	--	16.0
Net cash proceeds from issuance of common units	--	--	--	--	1,888.3	--	1,888.3
Cash contributions from owners	1,881.8	550.3	(550.3)	1,881.8	--	(1,881.8)	--
Other financing activities	(7.2)	--	--	(7.2)	(21.2)	--	(28.4)
Cash provided by financing activities	489.9	215.3	(220.5)	484.7	251.3	(248.1)	487.9
<b>Net change in cash and cash equivalents</b>	46.5	1.2	46.8	94.5	--	--	94.5
<b>Cash and cash equivalents, January 1</b>	--	69.6	(50.6)	19.0	--	--	19.0
<b>Cash and cash equivalents, June 30</b>	\$ 46.5	\$ 70.8	\$ (3.8)	\$ 113.5	\$ --	\$ --	\$ 113.5

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

### **For the Three and Six Months Ended June 30, 2017 and 2016**

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, 2016 (the “2016 Form 10-K”), as filed on February 24, 2017 with the U.S. Securities and Exchange Commission (“SEC”). Our financial statements have been prepared in accordance with generally accepted accounting principles (“GAAP”) in the United States (“U.S.”).

#### **Key References Used in this Management’s Discussion and Analysis**

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 Directors (the “Board”) of Enterprise GP; (ii) Richard H. Bachmann, who is also a director and Vice Chairman of the Board of Enterprise GP; and (iii) Dr. Ralph S. Cunningham. Ms. Duncan Williams and Mr. Bachmann also currently serve as managers of Dan Duncan LLC along with W. Randall Fowler, who is also a director and President of Enterprise GP.

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. Duncan Williams, who serves as Chairman of EPCO; (ii) Dr. Cunningham, who serves as Vice Chairman of EPCO; and (iii) Mr. Bachmann, who serves as the President and Chief Executive Officer of EPCO. Ms. Duncan Williams and Mr. Bachmann also currently serve as directors of EPCO along with Mr. Fowler, who is also the Executive Vice President and Chief Administrative Officer of EPCO. EPCO, together with its privately held affiliates, owned approximately 32% of our limited partner interests at June 30, 2017.

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 2017 compared to the second quarter of 2016. Likewise, the phrase “period-to-period” means the six months ended June 30, 2017 compared to the six months ended June 30, 2016.

## 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 Part I, Item 1A of our 2016 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 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 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 the 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 export and import terminals (including those used to export liquefied petroleum gases, or “LPG,” and ethane); crude oil gathering, transportation, storage, and export and import terminals; petrochemical and refined products transportation, storage, export and import terminals, and related services; and a marine transportation business that operates primarily on the U.S. inland and Intracoastal Waterway systems. Our assets currently include approximately 50,000 miles of pipelines; 260 MMBbls of storage capacity for NGLs, crude oil, petrochemicals and refined products; and 14 Bcf of natural gas storage capacity.

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.

Our operations are reported under four business segments: (i) NGL Pipelines & Services, (ii) Crude Oil Pipelines & Services, (iii) Natural Gas Pipelines & Services and (iv) Petrochemical & Refined Products Services. See Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report for information regarding our business segments.

We provide investors access to additional information regarding our partnership, including information relating to our governance procedures and principles, through our website, [www.enterpriseproducts.com](http://www.enterpriseproducts.com).

## **Significant Recent Developments**

### ***Successful Appeal in connection with ETP Matter***

In July 2017, a panel of the Dallas Court of Appeals issued a unanimous opinion in which we prevailed in our appeal against Energy Transfer Partners, L.P. (“ETP”). This appeal stemmed from an adverse 2014 jury verdict in Dallas, Texas in a lawsuit filed by ETP over a proposed pipeline project that was cancelled due to a lack of customer support.

In April 2011, Enterprise and ETP signed a series of agreements disclaiming any partnership or joint venture absent executed definitive documents and board approvals of the two companies. Definitive agreements were never executed and board approval was never obtained. The parties signed these disclaiming agreements precisely to avoid the type of lawsuit brought by ETP. We are grateful to the Dallas Court of Appeals for their hard work in this case and their reaffirmation of the importance of written contracts in business transactions.

For additional information regarding the appeal, see Note 14 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

### ***Announcement Regarding Potential Ethylene Marine Export Terminal***

In July 2017, we announced the execution of a letter of intent with Navigator Holdings Ltd. (“Navigator”) to develop an ethylene marine export terminal at our Morgan’s Point complex on the Houston Ship Channel. Formation of the 50/50 joint venture remains subject to the negotiation and execution of definitive agreements between us and Navigator, as well as approval by our respective boards of directors. Construction of the terminal is predicated on receiving sufficient long-term customer commitments.

We would manage the construction, operations and commercial activities of the proposed terminal. Our Morgan’s Point complex, which includes our ethane marine export terminal, features a 45-foot draft that can accommodate a variety of vessel and barge types. If constructed, the ethylene export terminal would be connected to our high-capacity ethylene salt dome storage and related pipeline system, both of which are under construction (see “*Plans to Develop Ethylene Storage and Transportation Projects*” below).

### ***Plans to Expand Orla Natural Gas Processing Plant in West Texas***

In June 2017, we announced plans to add 300 MMcf/d of incremental capacity at our cryogenic natural gas processing facility currently under construction near Orla, Texas in Reeves County. Orla II, a second processing train at the facility, will double the inlet capacity of the facility to 600 MMcf/d and increase extraction of NGLs from 40 MBPD to 80 MBPD.

NGLs from Orla will be delivered into our fully integrated NGL system, including the recently announced Shin Oak NGL Pipeline. Orla’s residue natural gas volumes will be transported to the Waha area through our Texas Intrastate system. The Orla II expansion project is designed to support the continued growth in NGL-rich natural gas production from the Delaware Basin of West Texas and southeastern New Mexico and is supported by long-term customer commitments.

Expansion of the Orla facility will bring the partnership’s total Permian Basin natural gas processing capacity to more than 1 Bcf/d with more than 150 MBPD of NGL extraction capacity. The Orla II capacity is expected to be placed into service during the third quarter of 2018.

### ***Plans to Build Shin Oak NGL Pipeline from Permian Basin to Mont Belvieu, Texas***

In April 2017, we announced plans to build a 571-mile pipeline to transport growing NGL production from the Permian Basin to our NGL fractionation and storage complex located in Mont Belvieu, Texas. The Shin Oak NGL pipeline will originate at our Hobbs facility in Gaines County, Texas. The 24-inch diameter pipeline is expected to have an initial design capacity of 250 MBPD and be expandable to 600 MBPD. The project is supported by long-term shipper commitments and is expected to be placed into service during the second quarter of 2019.

### ***Plans to Develop Ethylene Storage and Transportation Projects***

In April 2017, we announced two expansion projects that will further develop our ethylene infrastructure in the Houston, Texas area. First, we plan to repurpose a large, high-capacity ethane storage well at our Mont Belvieu, Texas complex. Following completion of this project, which is expected as early as the third quarter of 2018, the 5.3 MMBbl cavern will be able to inject/withdraw ethylene at a rate of 2,000 barrels per hour (“BPH”), expandable to 4,000 BPH. There are seven third party ethylene pipelines within two miles of the ethylene well, providing significant connectivity opportunities for the high-capacity system.

Further supporting our ethylene capabilities, we also plan to build a 24-mile, 12-inch diameter ethylene pipeline extending from Mont Belvieu to Bayport, Texas. The new pipeline would have the potential to connect both producing and consuming customers located south of the Houston Ship Channel to our facility in Mont Belvieu. The ethylene pipeline will be routed through our Morgan’s Point complex, which provides us with future flexibility should we develop an ethylene export marine terminal at the facility.

### ***Completion of Azure Acquisition***

In April 2017, we closed on the acquisition of a midstream energy business from Azure Midstream Partners, LP and its operating subsidiaries (collectively, “Azure”) for \$191.4 million in cash. The acquired business assets, which are located primarily in East Texas, include over 730 miles of natural gas gathering pipelines and two natural gas processing facilities with an aggregate processing capacity of 130 MMcf/d. The acquired business serves production from the Haynesville Shale and Bossier, Cotton Valley and Travis Peak formations.

For additional information regarding the Azure acquisition, see Note 4 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

### ***Plans to Build Ninth NGL Fractionator at Our Mont Belvieu, Texas Complex***

In March 2017, we resumed construction of our ninth NGL fractionator at our Mont Belvieu, Texas complex in anticipation of increased NGL production from the Permian Basin. The new fractionator, which is expected to be completed by mid-2018, would have a nameplate capacity of 85 MBPD. We have secured the necessary permits and emission credits for this project. Upon completion of this expansion project, we would have approximately 755 MBPD of total NGL fractionation capacity at our Mont Belvieu complex and a combined 1.2 MMBPD of capacity across all of our NGL fractionators.

### ***Plans to Construct Isobutane Dehydrogenation Unit at Mont Belvieu***

In January 2017, we announced plans to construct a new isobutane dehydrogenation (“iBDH”) unit at our Mont Belvieu complex that is expected to have the capability to produce 425,000 tons per year of isobutylene. The project, which is underwritten by long-term contracts with investment-grade customers, is expected to be completed in the fourth quarter of 2019. Isobutylene produced by the new plant will provide additional feedstocks for our downstream octane enhancement and petrochemical facilities.

Historically, steam crackers and refineries have been the major source of propane and butane olefins for downstream use. However, with the increased use of light-end feedstocks, specifically ethane, the need for on-purpose olefins production has increased. Like our propane dehydrogenation (“PDH”) facility, the iBDH plant will help meet market demand where traditional supplies have been reduced. The new iBDH plant will increase our production of high purity and low purity isobutylene, which are used as feedstock to manufacture lubricants, rubber products and alkylate for gasoline blendstock, as well as methyl tertiary butyl ether for export.

## 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,	
	2017	2016	2017	2016
Revenues	\$ 6,607.6	\$ 5,617.8	\$ 13,928.0	\$ 10,623.1
Costs and expenses:				
Operating costs and expenses:				
Cost of sales	4,731.1	3,838.7	10,066.8	7,047.0
Other operating costs and expenses	605.6	601.3	1,216.0	1,175.1
Depreciation, amortization and accretion expenses	379.2	360.3	755.4	718.5
Net losses attributable to asset sales	0.3	1.7	--	6.6
Asset impairment and related charges	14.0	20.2	25.2	21.9
Total operating costs and expenses	5,730.2	4,822.2	12,063.4	8,969.1
General and administrative costs	45.7	35.1	96.1	79.0
Total costs and expenses	5,775.9	4,857.3	12,159.5	9,048.1
Equity in income of unconsolidated affiliates	107.0	76.4	201.8	177.5
Operating income	938.7	836.9	1,970.3	1,752.5
Interest expense	(245.8)	(244.1)	(495.1)	(484.7)
Change in fair market value of Liquidity Option Agreement	(18.6)	(23.3)	(24.1)	(21.1)
Other, net	0.4	0.4	0.6	1.8
Benefit from (provision for) income taxes	(8.7)	0.1	(14.7)	(8.3)
Net income	666.0	570.0	1,437.0	1,240.2
Net income attributable to noncontrolling interests	(12.3)	(11.5)	(22.6)	(20.5)
Net income attributable to limited partners	\$ 653.7	\$ 558.5	\$ 1,414.4	\$ 1,219.7

### Consolidated Revenues

The following table presents each business segment's contribution to consolidated 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,	
	2017	2016	2017	2016
<b>NGL Pipelines &amp; Services:</b>				
Sales of NGLs and related products	\$ 2,158.0	\$ 2,060.4	\$ 5,045.2	\$ 4,003.9
Midstream services	462.6	455.1	921.2	915.4
Total	2,620.6	2,515.5	5,966.4	4,919.3
<b>Crude Oil Pipelines &amp; Services:</b>				
Sales of crude oil	1,705.1	1,482.2	3,323.7	2,603.3
Midstream services	194.5	177.8	383.1	345.3
Total	1,899.6	1,660.0	3,706.8	2,948.6
<b>Natural Gas Pipelines &amp; Services:</b>				
Sales of natural gas	560.6	305.7	1,104.6	620.7
Midstream services	225.6	230.0	442.8	465.0
Total	786.2	535.7	1,547.4	1,085.7
<b>Petrochemical &amp; Refined Products Services:</b>				
Sales of petrochemicals and refined products	1,114.1	713.4	2,325.2	1,266.6
Midstream services	187.1	193.2	382.2	402.9
Total	1,301.2	906.6	2,707.4	1,669.5
<b>Total consolidated revenues</b>	\$ 6,607.6	\$ 5,617.8	\$ 13,928.0	\$ 10,623.1

### Selected Energy Commodity Price Data

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

	Natural Gas, \$/MMBtu	Ethane, \$/gallon	Propane, \$/gallon	Normal Butane, \$/gallon	Isobutane, \$/gallon	Natural Gasoline, \$/gallon	Polymer Grade Propylene, \$/pound	Refinery Grade Propylene, \$/pound	WTI Crude Oil, \$/barrel	LLS Crude Oil, \$/barrel
	(1)	(2)	(2)	(2)	(2)	(2)	(3)	(3)	(4)	(4)
<b>2016 by quarter:</b>										
1st Quarter	\$2.09	\$0.16	\$0.38	\$0.53	\$0.53	\$0.76	\$0.31	\$0.18	\$33.45	\$35.11
2nd Quarter	\$1.95	\$0.20	\$0.49	\$0.62	\$0.63	\$0.96	\$0.33	\$0.19	\$45.59	\$47.35
3rd Quarter	\$2.81	\$0.19	\$0.47	\$0.63	\$0.67	\$0.98	\$0.38	\$0.24	\$44.94	\$46.52
4th Quarter	\$2.98	\$0.24	\$0.58	\$0.83	\$0.90	\$1.08	\$0.36	\$0.24	\$49.29	\$50.53
<b>2016 Averages</b>	<b>\$2.46</b>	<b>\$0.20</b>	<b>\$0.48</b>	<b>\$0.65</b>	<b>\$0.68</b>	<b>\$0.94</b>	<b>\$0.34</b>	<b>\$0.21</b>	<b>\$43.32</b>	<b>\$44.88</b>
<b>2017 by quarter:</b>										
1st Quarter	\$3.32	\$0.23	\$0.71	\$0.98	\$0.94	\$1.10	\$0.47	\$0.32	\$51.91	\$53.52
2nd Quarter	\$3.19	\$0.25	\$0.63	\$0.76	\$0.75	\$1.07	\$0.42	\$0.28	\$48.28	\$50.31
<b>2017 Averages</b>	<b>\$3.25</b>	<b>\$0.24</b>	<b>\$0.67</b>	<b>\$0.87</b>	<b>\$0.84</b>	<b>\$1.08</b>	<b>\$0.45</b>	<b>\$0.30</b>	<b>\$50.10</b>	<b>\$51.92</b>

- (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 IHS Chemical, a division of IHS Inc. ("IHS Chemical"). Refinery grade propylene prices represent weighted-average spot prices for such product as reported by IHS Chemical.
- (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 weighted-average indicative market price for NGLs was \$0.60 per gallon in the second quarter of 2017 versus \$0.50 per gallon during the second quarter of 2016. Likewise, the weighted-average indicative market price for NGLs was \$0.63 per gallon during the six months ended June 30, 2017 compared to \$0.45 per gallon during the same period in 2016.

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

We attempt to mitigate commodity price exposure through our hedging activities and the use of fee-based arrangements. See Note 12 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 2017 Compared to Second Quarter of 2016.* Total revenues for the second quarter of 2017 increased \$989.8 million when compared to the second quarter of 2016. Revenues from the marketing of crude oil, natural gas, petrochemicals, refined products and octane additives increased \$868.6 million quarter-to-quarter primarily due to higher sales prices, which accounted for a \$635.1 million increase, and higher sales volumes, which accounted for an additional \$233.5 million increase. Revenues from the marketing of NGLs increased a net \$97.6 million quarter-to-quarter primarily due to higher sales prices, which accounted for a \$636.4 million increase, partially offset by a \$538.8 million decrease due to lower sales volumes.

*Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016.* Total revenues for the six months ended June 30, 2017 increased \$3.3 billion when compared to the six months ended June 30, 2016. Revenues from the marketing of NGLs and crude oil increased a net \$1.76 billion period-to-period primarily due to higher sales prices, which accounted for a \$2.38 billion increase, partially offset by a \$614.2 million decrease due to lower sales volumes. Revenues from the marketing of natural gas, petrochemicals, refined products and octane additives increased \$1.51 billion period-to-period primarily due to higher sales prices, which accounted for a \$903.3 million increase, and higher sales volumes, which accounted for an additional \$606.4 million increase.

#### ***Operating costs and expenses***

*Second Quarter of 2017 Compared to Second Quarter of 2016.* Total operating costs and expenses for the second quarter of 2017 increased \$908.0 million when compared to the second quarter of 2016. The cost of sales associated with our marketing of crude oil, natural gas, petrochemicals, refined products and octane additives increased \$735.3 million quarter-to-quarter primarily due to higher purchase prices, which accounted for a \$520.7 million increase, and higher sales volumes, which accounted for an additional \$214.6 million increase. The cost of sales associated with our marketing of NGLs increased a net \$156.7 million quarter-to-quarter primarily due to higher purchase prices, which accounted for a \$601.0 million increase, partially offset by a \$444.3 million decrease due to lower sales volumes.

Other operating costs and expenses for the second quarter of 2017 increased a net \$4.3 million when compared to the second quarter of 2016. Other operating costs and expenses of our NGL Pipelines & Services segment increased \$26.0 million quarter-to-quarter, which includes an \$8.1 million increase due to our completion of the Morgan's Point Ethane Export Terminal in September 2016. Collectively, the remainder of our other operating costs and expenses decreased \$21.7 million quarter-to-quarter primarily due to \$17.4 million of proceeds received in connection with a legal settlement involving our Acadian Gas System in the second quarter of 2017.

Depreciation, amortization and accretion expense in operating costs and expenses for the second quarter of 2017 increased \$18.9 million when compared to the second quarter of 2016 primarily due to assets we constructed and placed into service since the second quarter of 2016.

Operating costs and expenses also include \$14.0 million and \$20.2 million of non-cash asset impairment and related charges for the second quarters of 2017 and 2016, respectively. Our non-cash asset impairment charges for the second quarter of 2017 primarily relate to the write-down of natural gas pipeline laterals in Texas.

*Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016.* Total operating costs and expenses for the six months ended June 30, 2017 increased \$3.09 billion when compared to the six months ended June 30, 2016. The cost of sales associated with our marketing of NGLs and crude oil increased a net \$1.66 billion period-to-period primarily due to higher purchase prices, which accounted for a \$2.17 billion increase, partially offset by a \$516.5 million decrease due to lower sales volumes. The cost of sales associated with our marketing of natural gas, petrochemicals, refined products and octane additives increased \$1.37 billion period-to-period primarily due to higher purchase prices, which accounted for an \$835.4 million increase, and higher sales volumes, which accounted for an additional \$530.7 million increase.



Other operating costs and expenses for the six months ended June 30, 2017 increased a net \$40.9 million when compared to the six months ended June 30, 2016. Other operating costs and expenses of our NGL Pipelines & Services segment increased \$60.0 million period-to-period, which includes a \$17.4 million increase due to our completion of the Morgan's Point Ethane Export Terminal in September 2016. Collectively, the remainder of our other operating costs and expenses decreased \$19.1 million period-to-period primarily due to \$17.4 million of proceeds received in a legal settlement in the second quarter of 2017.

Depreciation, amortization and accretion expense in operating costs and expenses for the six months ended June 30, 2017 increased \$36.9 million when compared to the six months ended June 30, 2016 primarily due to assets we constructed and placed into service since the second quarter of 2016.

Operating costs and expenses also include \$25.2 million and \$21.9 million of non-cash asset impairment and related charges for the six months ended June 30, 2017 and 2016, respectively. Our non-cash asset impairment charges for the six months ended June 30, 2017 primarily relate to the write-down of materials held as spare parts and natural gas pipeline laterals in Texas.

#### General and administrative costs

General and administrative costs for the three and six months ended June 30, 2017 increased \$10.6 million and \$17.1 million, respectively, when compared to the same periods in 2016 primarily due to higher costs for legal services. Other factors contributing to the increase in general and administrative costs are \$5.6 million of costs recorded in the first quarter of 2017 in connection with sales and use tax audits and \$1.1 million of transaction expenses for the Azure acquisition completed in the second quarter of 2017.

#### Equity in income of unconsolidated affiliates

Equity income from our unconsolidated affiliates for the three and six months ended June 30, 2017 increased \$30.6 million and \$24.3 million, respectively, when compared to the same periods in 2016 primarily due to an increase in earnings from our investments in crude oil pipelines.

#### Operating income

Operating income for the three and six months ended June 30, 2017 increased \$101.8 million and \$217.8 million, respectively, when compared to the same periods in 2016 due to the previously described quarter-to-quarter and period-to-period changes in revenues, operating costs and expenses, general and administrative costs and equity in income of unconsolidated affiliates.

#### Interest expense

Interest expense for the three and six months ended June 30, 2017 increased \$1.7 million and \$10.4 million, respectively, when compared to the same periods in 2016. 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,	
	2017	2016	2017	2016
Interest charged on debt principal outstanding	\$ 272.8	\$ 273.7	\$ 545.7	\$ 542.0
Impact of interest rate hedging program, including related amortization	9.3	7.7	18.0	14.1
Interest costs capitalized in connection with construction projects (1)	(44.5)	(46.4)	(84.1)	(88.9)
Other (2)	8.2	9.1	15.5	17.5
Total	\$ 245.8	\$ 244.1	\$ 495.1	\$ 484.7

- (1) We capitalize interest costs incurred on funds used to construct property, plant and equipment while the asset is in its construction phase. Capitalized interest amounts become part of the historical cost of an asset and are charged to earnings (as a component of depreciation expense) on a straight line basis over the estimated useful life of the asset once the asset enters its intended service. When capitalized interest is recorded, it reduces interest expense from what it would be otherwise. 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, decreased a net \$0.9 million quarter-to-quarter primarily due to the effect of lower overall interest rates during the second quarter of 2017, which accounted for an \$8.6 million decrease, partially offset by increased debt principal amounts outstanding during the second quarter of 2017, which accounted for a \$7.7 million increase. Our weighted-average debt principal balance for the second quarter of 2017 was \$23.6 billion compared to \$22.93 billion for the second quarter of 2016. 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” and “Capital Spending” within this Part I, Item 2.

For the six months ended June 30, 2017, interest charged on debt principal outstanding increased a net \$3.7 million period-to-period primarily due to increased debt principal amounts outstanding during the six months ended June 30, 2017, which accounted for a \$16.9 million increase, partially offset by the effect of lower overall interest rates during the six months ended June 30, 2017, which accounted for a \$13.2 million decrease. Our weighted-average debt principal balance for the six months ended June 30, 2017 was \$23.63 billion compared to \$22.94 billion for the six months ended June 30, 2016.

#### Change in fair value of Liquidity Option Agreement

The change in fair value of the Liquidity Option Agreement reflects non-cash expense attributable to accretion and changes in management estimates regarding inputs to the valuation model. For the three months ended June 30, 2017, our expense resulting from changes in fair value of the Liquidity Option Agreement decreased \$4.7 million when compared to the same period in 2016. For the six months ended June 30, 2017, this expense increased \$3.0 million period-to-period. For information regarding the Liquidity Option Agreement, see Note 14 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

#### Income taxes

Income taxes primarily reflect our state tax obligations under the Revised Texas Franchise Tax. Our provision for income taxes for the three and six months ended June 30, 2017 increased \$8.8 million and \$6.4 million, respectively, when compared to the same periods in 2016.

#### **Business Segment Highlights**

We evaluate segment performance based on our financial measure of gross operating margin. Gross operating margin is an important performance measure of the core profitability of our operations and forms the basis of our internal financial reporting. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results.

The following table presents gross operating margin by segment and non-GAAP total gross operating margin for the periods indicated (dollars in millions):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2017	2016	2017	2016
Gross operating margin by segment:				
NGL Pipelines & Services	\$ 759.9	\$ 719.1	\$ 1,615.9	\$ 1,502.8
Crude Oil Pipelines & Services	236.7	177.4	501.3	379.7
Natural Gas Pipelines & Services	194.4	177.4	365.3	355.1
Petrochemical & Refined Products Services	188.4	175.5	370.2	330.3
Total segment gross operating margin (1)	1,379.4	1,249.4	2,852.7	2,567.9
Net adjustment for shipper make-up rights	(1.5)	4.8	(5.7)	10.6
Total gross operating margin	\$ 1,377.9	\$ 1,254.2	\$ 2,847.0	\$ 2,578.5

- (1) Within the context of this table, total segment gross operating margin represents a subtotal and corresponds to measures similarly titled within our business segment disclosures found in Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Total gross operating margin includes equity in the earnings of unconsolidated affiliates, but is exclusive of other income and expense transactions, income taxes, the cumulative effect of changes in accounting principles and extraordinary charges. Total gross operating margin is presented on a 100% basis before any allocation of earnings to noncontrolling interests.

Gross operating margin by segment for NGL Pipelines & Services and Crude Oil Pipelines & Services reflect adjustments for shipper make-up rights that are included in management's evaluation of segment results. However, these adjustments are excluded from non-GAAP total gross operating margin.

The GAAP financial measure most directly comparable to total gross operating margin is operating income. For a discussion of operating income and its components, see the previous section titled "Consolidated Income Statement Highlights" within this Item 2. The following table presents a reconciliation of operating income to total gross operating margin for the periods indicated (dollars in millions):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2017	2016	2017	2016
Operating income (GAAP)	\$ 938.7	\$ 836.9	\$ 1,970.3	\$ 1,752.5
<i>Adjustments to reconcile operating income to total gross operating margin:</i>				
Add depreciation, amortization and accretion expense	379.2	360.3	755.4	718.5
Add asset impairment and related charges in operating costs and expenses	14.0	20.2	25.2	21.9
Add net losses attributable to asset sales	0.3	1.7	--	6.6
Add general and administrative costs	45.7	35.1	96.1	79.0
Total gross operating margin (non-GAAP)	\$ 1,377.9	\$ 1,254.2	\$ 2,847.0	\$ 2,578.5

Each of our business segments benefits from the supporting role of our marketing activities. The main purpose of our marketing activities is to support the utilization and expansion of assets across our midstream energy asset network by increasing the volumes handled by such assets, which results in additional fee-based earnings for each business segment. In performing these support roles, our marketing activities also seek to participate in supply and demand opportunities as a supplemental source of gross operating margin for the partnership. The financial results of our marketing efforts fluctuate due to changes in volumes handled and overall market conditions, which are influenced by current and forward market prices for the products bought and sold.

The following information highlights significant changes in our quarter-to-quarter and period-to-period segment results (i.e., our gross operating margin by segment amounts) and the primary drivers of such changes. The volume statistics presented 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,	
	2017	2016	2017	2016
Segment gross operating margin:				
Natural gas processing and related NGL marketing activities	\$ 204.7	\$ 181.3	\$ 482.6	\$ 415.2
NGL pipelines, storage and terminals	436.3	408.2	891.2	834.9
NGL fractionation	118.9	129.6	242.1	252.7
Total	\$ 759.9	\$ 719.1	\$ 1,615.9	\$ 1,502.8
Selected volumetric data:				
Equity NGL production (MBPD) (1)	164	143	157	145
Fee-based natural gas processing (MMcf/d) (2)	4,660	4,995	4,598	4,939
NGL pipeline transportation volumes (MBPD)	3,083	2,992	3,160	2,973
NGL marine terminal volumes (MBPD)	474	450	521	453
NGL fractionation volumes (MBPD)	841	840	820	838

(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*

*Second Quarter of 2017 Compared to Second Quarter of 2016.* Gross operating margin from natural gas processing and related NGL marketing activities for the second quarter of 2017 increased \$23.4 million when compared to the second quarter of 2016. In general, gross operating margin from our NGL marketing activities increased a net \$19.1 million quarter-to-quarter primarily due to higher sales margins, which accounted for a \$44.8 million increase, partially offset by a \$26.5 million decrease due to lower sales volumes. Results from NGL marketing's activities in support of our storage assets increased \$15.4 million quarter-to-quarter, with all other marketing strategies accounting for a combined \$3.7 million increase quarter-to-quarter.

Collectively, gross operating margin from our natural gas processing plants in the Rocky Mountains, Louisiana and Mississippi increased \$11.6 million quarter-to-quarter primarily due to higher processing margins, which accounted for a \$7.4 million increase, and a \$4.4 million decline in operating expenses quarter-to-quarter. Gross operating margin from our natural gas processing plants in South Texas decreased \$6.1 million quarter-to-quarter primarily due to lower fee-based processing volumes of 334 MMcf/d from the Eagle Ford Shale region, which accounted for a \$5.8 million decrease.

*Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016.* Gross operating margin from natural gas processing and related NGL marketing activities for the six months ended June 30, 2017 increased \$67.4 million when compared to the six months ended June 30, 2016. Gross operating margin from our NGL marketing activities increased a net \$42.4 million period-to-period primarily due to higher sales volumes, which accounted for a \$70.3 million increase, partially offset by a \$32.0 million decrease due to lower sales margins. Results from NGL marketing's activities in support of our storage assets increased \$37.3 million period-to-period, with NGL marketing's other strategies yielding a combined \$5.1 million period-to-period increase.

Gross operating margin from our natural gas processing plants increased \$25.0 million period-to-period primarily due to higher processing margins.

### *NGL pipelines, storage and terminals*

*Second Quarter of 2017 Compared to Second Quarter of 2016.* Gross operating margin from NGL pipelines, storage and terminal assets for the second quarter of 2017 increased \$28.1 million when compared to the second quarter of 2016.

Gross operating margin from our storage complex in Mont Belvieu for NGLs and related products increased \$13.0 million quarter-to-quarter primarily due to higher fees, of which several increased in January 2017. Gross operating margin from our Appalachia-to-Texas Express (or “ATEX”) pipeline increased \$11.4 million quarter-to-quarter primarily due to contractual increases in committed shipper volumes, which accounted for a \$7.1 million increase, and higher volumes from uncommitted (or “walk-up”) shippers, which accounted for a \$6.2 million increase. Transportation volumes for ATEX increased 8 MBPD quarter-to-quarter. Gross operating margin from our Dixie Pipeline and related terminals increased \$6.4 million quarter-to-quarter primarily due to higher transportation volumes, which increased 35 MBPD quarter-to-quarter. Lastly, gross operating margin from our Rio Grande Pipeline increased \$5.0 million quarter-to-quarter primarily due to an increase in shipper deficiency fees.

Gross operating margin from our equity investments in the Texas Express Gathering System and the Texas Express and Front Range Pipelines increased a combined \$6.7 million quarter-to-quarter primarily due to contractual increases in committed shipper volumes. Actual transportation volumes on these pipelines increased 10 MBPD quarter-to-quarter (net to our interest).

Gross operating margin from our South Texas NGL Pipeline System decreased \$6.6 million quarter-to-quarter primarily due to lower transportation fees, which accounted for \$3.2 million of the quarter-to-quarter decrease, along with lower transportation volumes, which accounted for an additional \$2.0 million of the decrease. As a result of reduced producer drilling activity in the Eagle Ford Shale, transportation volumes on the South Texas NGL Pipeline System decreased 18 MBPD quarter-to-quarter. Gross operating margin from our Mid-America Pipeline, Seminole Pipeline and related terminals decreased \$6.1 million quarter-to-quarter primarily due to lower average transportation fees and a 4 MBPD decrease in transportation volumes, which collectively accounted for \$5.2 million of the quarter-to-quarter decrease.

Gross operating margin from our Enterprise Hydrocarbons Terminal (“EHT”), Morgan’s Point Ethane Export Terminal and Houston Ship Channel Pipeline System decreased a combined \$1.6 million quarter-to-quarter. Volumes at EHT decreased 43 MBPD quarter-to-quarter due to lower LPG exports, while ethane loading volumes at Morgan’s Point increased 67 MBPD. Transportation volumes on the related Houston Ship Channel Pipeline System increased 55 MBPD quarter-to-quarter primarily due to shipments of ethane from our Mont Belvieu complex to our Morgan’s Point Ethane Export Terminal, which was placed into commercial operations in September 2016.

*Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016.* Gross operating margin from NGL pipelines, storage and terminal assets for the six months ended June 30, 2017 increased \$56.3 million when compared to the six months ended June 30, 2016.

Gross operating margin from our storage complex in Mont Belvieu for NGLs and related products increased \$28.8 million period-to-period primarily due to higher fees in 2017. In addition, gross operating margin from ATEX increased \$20.0 million period-to-period primarily due to contractual increases in committed shipper volumes, which accounted for a \$12.9 million increase, and higher volumes from walk-up shippers, which accounted for an \$8.1 million increase. Transportation volumes for ATEX increased 8 MBPD period-to-period.

Gross operating margin from our EHT, Morgan’s Point Ethane Export Terminal and Houston Ship Channel Pipeline System increased a combined \$12.6 million period-to-period primarily due to higher volumes. Ethane loading volumes at our Morgan’s Point Ethane Export Terminal were 63 MBPD during the first six months of 2017. As noted previously, this terminal commenced operations in September 2016. In addition, transportation volumes on our Houston Ship Channel Pipeline System increased 101 MBPD period-to-period primarily due to shipments of ethane from Mont Belvieu to the Morgan’s Point terminal. LPG export volumes at EHT increased 5 MBPD period-to-period.

Gross operating margin from our South Texas NGL Pipeline System decreased \$10.3 million period-to-period primarily due to lower transportation volumes, which accounted for a \$4.3 million decrease, and lower transportation fees, which accounted for a \$4.1 million decrease. Transportation volumes for the South Texas NGL Pipeline System decreased 18 MBPD period-to-period. Gross operating margin from our Mid-America Pipeline, Seminole Pipeline and related terminals decreased a combined \$8.1 million period-to-period primarily due to higher operating expenses, which accounted for a \$14.6 million period-to-period decrease, partially offset by a 51 MBPD increase in transportation volumes, which accounted for a \$7.4 million period-to-period increase.

### *NGL fractionation*

*Second Quarter of 2017 Compared to Second Quarter of 2016.* Gross operating margin from NGL fractionation for the second quarter of 2017 decreased \$10.7 million when compared to the second quarter of 2016. Gross operating margin from our Mont Belvieu NGL fractionators decreased \$5.9 million quarter-to-quarter primarily due to an increase in operating costs (storage, power and maintenance), which accounted for a \$17.3 million decrease, partially offset by higher revenues of \$10.3 million. The increase in NGL fractionation revenues at Mont Belvieu is generally attributable to higher average fees, which accounted for \$7.0 million of the increase, and a 15 MBPD increase in fractionation volumes (net to our interest), which accounted for \$3.7 million of the increase. Gross operating margin from our Hobbs NGL fractionator decreased \$2.9 million quarter-to-quarter primarily due to higher maintenance expenses.

NGL fractionation volumes at our Shoup and Armstrong facilities decreased a combined 19 MBPD quarter-to-quarter primarily due to lower natural gas production in the region attributable to the current energy commodity price environment. Gross operating margin from these NGL fractionators was essentially unchanged quarter-to-quarter as lower operating costs offset the lower revenues associated with the decrease in volumes.

*Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016.* Gross operating margin from NGL fractionation for the six months ended June 30, 2017 decreased \$10.6 million when compared to the six months ended June 30, 2016. Gross operating margin from our Shoup and Armstrong facilities decreased \$3.0 million period-to-period primarily due to a 25 MBPD decrease in fractionation volumes. As noted above, regional natural gas production continues to be suppressed due to the energy commodity price environment. Gross operating margin from the remainder of our NGL fractionation facilities decreased \$7.6 million period-to-period primarily due to higher operating costs.

### *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,	
	2017	2016	2017	2016
Segment gross operating margin	\$ 236.7	\$ 177.4	\$ 501.3	\$ 379.7
Selected volumetric data:				
Crude oil pipeline transportation volumes (MBPD)	1,475	1,358	1,416	1,376
Crude oil marine terminal volumes (MBPD)	488	514	482	497

*Second Quarter of 2017 Compared to Second Quarter of 2016.* Gross operating margin from our Crude Oil Pipelines & Services segment for the second quarter of 2017 increased a net \$59.3 million when compared to the second quarter of 2016.

Gross operating margin from crude oil marketing and related trucking activities increased \$33.4 million quarter-to-quarter primarily due to a \$62.3 million benefit related to non-cash mark-to-market results partially offset by a \$28.9 million decrease in earnings from settled marketing activities. Mark-to-market income for this business was a gain of \$14.9 million for the second quarter of 2017 versus a loss of \$47.4 million for the second quarter of 2016.

Gross operating margin from our West Texas System and equity investment in the Eagle Ford Crude Oil Pipeline System increased a combined \$15.2 million quarter-to-quarter primarily due to a 121 MBPD increase in crude oil transportation volumes from the Permian Basin. Of the 121 MBPD quarter-to-quarter increase in transportation volumes, 98 MBPD (net to our interest) is attributable to the Eagle Ford Crude Oil Pipeline System. The increase in crude oil transportation volumes from the West Texas region is attributable to increased producer drilling activity across the Permian Basin.

Gross operating margin from our equity investment in the Seaway Pipeline increased \$7.9 million quarter-to-quarter primarily due to higher firm capacity revenues attributable to the Seaway Loop. Crude oil transportation volumes for the Seaway Pipeline increased 35 MBPD quarter-to-quarter (net to our interest).

Gross operating margin from our EFS Midstream System increased \$6.5 million quarter-to-quarter primarily due to increased deficiency fee revenues. The EFS Midstream System serves producers in the Eagle Ford Shale, providing condensate gathering and processing services as well as gathering, treating and compression services for associated natural gas production. Due to decreased producer drilling activity, condensate volumes for this system decreased 27 MBPD quarter-to-quarter and associated natural gas volumes decreased 132 MMcf/d quarter-to-quarter. Gross operating margin for the system decreased \$21.8 million quarter-to-quarter due to the lower throughput volumes; however, this decrease was more than offset by a \$30.9 million quarter-to-quarter increase in deficiency fee revenues associated with producer volume commitments.

*Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016.* Gross operating margin from our Crude Oil Pipelines & Services segment for the six months ended June 30, 2017 increased a net \$121.6 million when compared to the six months ended June 30, 2016.

Gross operating margin from crude oil marketing and related trucking activities increased \$89.7 million period-to-period primarily due to a \$95.4 million benefit related to non-cash mark-to-market results partially offset by a \$5.7 million decrease in earnings from settled marketing activities. Mark-to-market income for this business was a gain of \$34.7 million for the first six months of 2017 versus a loss of \$60.7 million for the same period of 2017.

Gross operating margin from our West Texas System and equity investment in the Eagle Ford Crude Oil Pipeline System increased a combined \$29.9 million period-to-period primarily due to an 88 MBPD increase in crude oil transportation volumes. Of the 88 MBPD period-to-period increase in transportation volumes, 68 MBPD (net to our interest) is attributable to the Eagle Ford Crude Oil Pipeline System.

Gross operating margin from our EFS Midstream System increased \$14.6 million period-to-period primarily due to increased deficiency fee revenues. Condensate volumes for this system decreased 31 MBPD period-to-period and associated natural gas volumes decreased 134 MMcf/d period-to-period. Gross operating margin for the system decreased \$48.1 million period-to-period primarily due to the lower throughput volumes; however, this decrease was more than offset by a \$66.6 million period-to-period increase in deficiency fee revenues associated with producer volume commitments.

Gross operating margin from our South Texas Crude Oil Pipeline System decreased \$11.9 million period-to-period primarily due to a 38 MBPD decrease in transportation volumes. As with the EFS Midstream System, the decrease in crude oil transportation volumes in South Texas is attributable to reduced producer drilling activity in the Eagle Ford Shale.

#### 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,	
	2017	2016	2017	2016
Segment gross operating margin	\$ 194.4	\$ 177.4	\$ 365.3	\$ 355.1
Selected volumetric data:				
Natural gas pipeline transportation volumes (BBtus/d)	12,232	12,079	11,934	11,987

*Second Quarter of 2017 Compared to Second Quarter of 2016.* Gross operating margin from our Natural Gas Pipelines & Services segment for the second quarter of 2017 increased a net \$17.0 million when compared to the second quarter of 2016.

Gross operating margin from our Acadian Gas System increased \$15.6 million quarter-to-quarter primarily due to \$17.4 million of proceeds received in a legal settlement in the second quarter of 2017 for lost revenues and damages associated with the Bayou Corne sinkhole incident caused by third parties in 2012, partially offset by lower firm capacity reservation revenues on the Haynesville Extension pipeline, which accounted for a \$2.3 million quarter-to-quarter decrease. Gross operating margin on our Haynesville Gathering System increased \$2.3 million quarter-to-quarter primarily due to higher gathering volumes. When compared to the second quarter of 2016, natural gas volumes handled by our Haynesville Gathering System in the second quarter of 2017 increased 169 BBtus/d and those on our Haynesville Extension pipeline increased 218 BBtus/d. In general, our Louisiana and East Texas natural gas pipelines continue to benefit from increased producer drilling activity in the Haynesville Shale and surrounding areas.

Gross operating margin from our Permian Basin Gathering System increased \$3.1 million quarter-to-quarter primarily due to a 102 BBtus/d increase in natural gas gathering volumes on the Carlsbad pipeline. Natural gas production in the Permian Basin has increased in connection with a significant rise in crude oil production across West Texas and southeastern New Mexico.

Gross operating margin from our Texas Intrastate System decreased \$7.3 million quarter-to-quarter primarily due to lower natural gas transportation volumes, which accounted for \$2.6 million of the decrease, lower firm transportation fees, which accounted for an additional \$2.6 million of the decrease, and higher maintenance costs of \$3.4 million quarter-to-quarter. Natural gas transportation volumes for the Texas Intrastate System decreased 412 BBtus/d quarter-to-quarter reflecting reduced drilling activity in the Eagle Ford Shale.

Gross operating margin from our natural gas marketing activities increased \$4.2 million quarter-to-quarter primarily due to higher sales margins.

*Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016.* Gross operating margin from our Natural Gas Pipelines & Services segment for the six months ended June 30, 2017 increased a net \$10.2 million when compared to the six months ended June 30, 2016.

Gross operating margin from our Acadian Gas System increased \$12.9 million period-to-period primarily due to the \$17.4 million gain described above that was recorded in the second quarter of 2017, partially offset by lower firm capacity reservation revenues on the Haynesville Extension pipeline, which accounted for a \$5.0 million period-to-period decrease. Gross operating margin from our Haynesville Gathering System increased \$1.1 million period-to-period primarily due to higher gathering volumes, which accounted for a \$4.4 million increase, partially offset by the effects of lower average gathering fees, which accounted for a \$2.4 million decrease. Transportation volumes for the Haynesville Extension pipeline, which is a component of the Acadian Gas System, increased 225 BBtus/d while volumes for the Haynesville Gathering System increased 126 BBtus/d.

Gross operating margin from our Permian Basin Gathering System increased \$11.4 million period-to-period primarily due to an increase in compression and treating revenues, which accounted for a \$6.0 million increase, and a 135 BBtus/d increase in natural gas gathering volumes on the Carlsbad pipeline, which accounted for \$5.0 million of the increase. As noted previously, natural gas production in the Permian Basin has increased in connection with a significant rise in crude oil production across West Texas and southeastern New Mexico.

Gross operating margin from our Texas Intrastate System decreased \$18.1 million period-to-period primarily due to lower firm transportation fees, which accounted for a \$9.7 million decrease, lower natural gas transportation volumes, which accounted for a \$5.9 million decrease, and higher maintenance costs, which accounted for \$2.9 million of the period-to-period decrease. Natural gas transportation volumes for the Texas Intrastate System decreased 444 BBtus/d period-to-period reflecting reduced drilling activity in the Eagle Ford Shale.

Gross operating margin from our Jonah Gathering System decreased \$10.8 million period-to-period primarily due to a 120 BBtus/d decline in natural gas gathering volumes.

Gross operating margin from our natural gas marketing activities increased \$9.1 million period-to-period primarily due to an increase in average sales margins, which accounted for \$4.3 million of the increase, and higher sales volumes, which accounted for an additional \$2.2 million of the 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,	
	2017	2016	2017	2016
Segment gross operating margin:				
Propylene fractionation and related activities	\$ 62.0	\$ 52.8	\$ 130.6	\$ 104.9
Butane isomerization and related operations	18.2	17.3	29.1	33.4
Octane enhancement and related plant operations	38.6	21.2	57.5	11.0
Refined products pipelines and related activities	69.5	74.1	146.2	161.1
Marine transportation and other	0.1	10.1	6.8	19.9
Total	\$ 188.4	\$ 175.5	\$ 370.2	\$ 330.3
Selected volumetric data:				
Propylene fractionation plant production volumes (MBPD)	81	80	81	75
Butane isomerization volumes (MBPD)	116	114	104	112
Standalone DIB processing volumes (MBPD)	81	90	82	93
Octane additive and related plant production volumes (MBPD)	30	22	25	16
Pipeline transportation volumes, primarily refined products and petrochemicals (MBPD)	800	874	813	863
Refined products and petrochemical marine terminal volumes (MBPD)	471	410	435	379

#### *Propylene fractionation and related activities*

*Second Quarter of 2017 Compared to Second Quarter of 2016.* Gross operating margin from propylene fractionation and related marketing activities for the second quarter of 2017 increased a net \$9.2 million when compared to the second quarter of 2016. Gross operating margin from our Mont Belvieu propylene fractionation plants increased \$10.1 million quarter-to-quarter primarily due to higher propylene sales volumes, which accounted for an \$8.7 million increase, and higher propylene sales margins, which accounted for a \$1.4 million increase. In addition, gross operating margin for propylene fractionation and related activities for the second quarter of 2017 reflects \$2.1 million of start-up costs attributable to our PDH facility compared to \$3.9 million of such costs for the second quarter of 2016.

Gross operating margin from propylene export activities decreased a net \$1.7 million quarter-to-quarter primarily due to lower average loading fees, which accounted for a \$3.8 million decrease, partially offset by lower operating costs, which accounted for a \$1.6 million increase.

*Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016.* Gross operating margin from propylene fractionation and related marketing activities for the six months ended June 30, 2017 increased a net \$25.7 million when compared to the six months ended June 30, 2016. Gross operating margin from our Mont Belvieu propylene fractionation plants increased \$35.9 million period-to-period primarily due to higher propylene sales margins, which accounted for a \$19.2 million increase, and higher propylene sales volumes, which accounted for an additional \$14.2 million increase. Start-up costs attributable to the PDH facility, which are reflected in gross operating margin for propylene fractionation and related activities, increased \$3.8 million period-to-period.

Gross operating margin from propylene export activities decreased a net \$3.3 million period-to-period primarily due to lower average loading fees, which accounted for a \$6.8 million decrease, partially offset by lower operating costs, which accounted for a \$2.8 million increase.

#### *Isomerization and related operations*

*Second Quarter of 2017 Compared to Second Quarter of 2016.* Gross operating margin from butane isomerization and deisobutanizer (“DIB”) operations for the second quarter of 2017 increased \$0.9 million when compared to the second quarter of 2016 primarily due to higher processing fees at our standalone DIB units in 2017.

*Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016.* Gross operating margin from butane isomerization and DIB operations for the six months ended June 30, 2017 decreased \$4.3 million when compared to the six months ended June 30, 2016. Gross operating margin from butane isomerization decreased \$3.1 million period-to-period primarily due to higher power and maintenance costs in 2017.

#### *Octane enhancement and related operations*

*Second Quarter of 2017 Compared to Second Quarter of 2016.* Gross operating margin from our octane enhancement facility and high purity isobutylene (“HPIB”) plant for the second quarter of 2017 increased \$17.4 million when compared to the second quarter of 2016. Gross operating margin from our octane enhancement facility increased \$17.1 million quarter-to-quarter primarily due to lower major maintenance costs, which accounted for \$11.1 million of the increase, and higher revenues, which accounted for \$6.9 million of the increase. Of the quarter-to-quarter increase in revenues, higher sales volumes during the second quarter of 2017 accounted for \$4.3 million of the increase, while higher average sales margins resulted in a \$2.2 million increase.

*Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016.* Gross operating margin from our octane enhancement facility and HPIB plant for the six months ended June 30, 2017 increased \$46.5 million when compared to the six months ended June 30, 2016. Gross operating margin from our octane enhancement facility increased \$47.6 million period-to-period primarily due to higher sales volumes, which accounted for \$25.8 million of the increase, and lower major maintenance costs, which accounted for \$20.9 million of the increase.

Historically, our octane enhancement plant experienced downtime annually for major maintenance activities. During 2016, we completed modifications to our octane enhancement plant to alleviate the need for such yearly outages. We now expect downtime for major maintenance activities at our octane enhancement plant once every three years. As a result of these modifications, plant production volumes increased 9 MBPD period-to-period.

#### *Refined products pipelines and related activities*

*Second Quarter of 2017 Compared to Second Quarter of 2016.* Gross operating margin from refined products pipelines and related marketing activities for the second quarter of 2017 decreased \$4.6 million when compared to the second quarter of 2016. Gross operating margin from refined products marketing decreased \$12.9 million quarter-to-quarter primarily due to lower refined products sales margins, which accounted for a \$21.2 million decrease, partially offset by an \$8.3 million quarter-to-quarter increase in mark-to-market income.

Gross operating margin from our TE Products Pipeline increased \$7.5 million quarter-to-quarter primarily due to lower operating costs, which declined \$5.1 million quarter-to-quarter. Transportation volumes for the TE Products Pipeline decreased 43 MBPD quarter-to-quarter primarily due to lower intrastate refined products movements during the second quarter of 2017.

*Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016.* Gross operating margin from refined products pipelines and related marketing activities for the six months ended June 30, 2017 decreased \$14.9 million when compared to the six months ended June 30, 2016.

Gross operating margin from refined products marketing decreased \$16.0 million period-to-period primarily due to lower refined products sales margins, which accounted for a \$26.0 million decrease, partially offset by a \$9.6 million period-to-period increase in mark-to-market income.

Gross operating margin from our TE Products Pipeline decreased \$4.1 million period-to-period primarily due to lower transportation volumes, which accounted for a \$10.2 million decrease, partially offset by lower operating costs, which accounted for an \$8.3 million increase. Transportation volumes for the TE Products Pipeline decreased 24 MBPD period-to-period. Gross operating margin from our refined products terminals increased \$2.4 million period-to-period primarily due to higher throughput volumes at our Port Arthur, Texas terminal.

### *Marine transportation and other*

*Second Quarter of 2017 Compared to Second Quarter of 2016.* Gross operating margin from marine transportation and other for the second quarter of 2017 decreased \$10.0 million when compared to the second quarter of 2016. Gross operating margin attributable to our marine transportation business decreased \$6.4 million quarter-to-quarter primarily due to lower average transport fees, which are generally attributable to increased competition within this line of business. Our marine transportation assets are used to transport refined and other petroleum products along key U.S. inland and Intracoastal Waterway systems.

*Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016.* Gross operating margin from marine transportation and other for the six months ended June 30, 2017 decreased \$13.1 million when compared to the six months ended June 30, 2016. Gross operating margin attributable to our marine transportation business decreased \$9.8 million period-to-period primarily due to lower average transport fees.

### **Liquidity and Capital Resources**

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. At June 30, 2017, we had \$4.07 billion of consolidated liquidity, which was comprised of \$4.04 billion of available borrowing capacity under EPO's revolving credit facilities and \$28.6 million of unrestricted cash on hand.

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.

### ***Consolidated Debt***

The following table presents scheduled maturities of our consolidated debt obligations outstanding at June 30, 2017 for the years indicated (dollars in millions):

	Scheduled Maturities of Debt						
	Total	Remainder of 2017	2018	2019	2020	2021	Thereafter
Commercial Paper Notes	\$ 1,455.2	\$ 1,455.2	\$ --	\$ --	\$ --	\$ --	\$ --
Senior Notes	20,650.0	800.0	1,100.0	1,500.0	1,500.0	575.0	15,175.0
Junior Subordinated Notes	1,474.4	--	--	--	--	--	1,474.4
Total	\$ 23,579.6	\$ 2,255.2	\$ 1,100.0	\$ 1,500.0	\$ 1,500.0	\$ 575.0	\$ 16,649.4

For additional information regarding our debt agreements, see Note 7 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

### ***Expected renewal of 364-Day Credit Agreement***

In September 2016, EPO entered into a 364-Day Credit Agreement that matures in September 2017. Under this credit agreement, EPO may borrow up to \$1.5 billion (which may be increased by up to \$200 million to \$1.7 billion at EPO's election, provided certain conditions are met) at a variable interest rate for a term of 364 days. At June 30, 2017, there were no principal amounts outstanding under this revolving credit agreement. We expect to renew this credit agreement during the third quarter of 2017.

### ***Issuance of Common Units***

The following table summarizes the issuance of common units in connection with our at-the-market (“ATM”) program, distribution reinvestment plan (“DRIP”) and employee unit purchase plan (“EUPP”) for the quarterly periods indicated (dollars in millions, number of units issued as shown):

	<b>Number of Common Units Issued</b>	<b>Net Cash Proceeds Received</b>
Three months ended March 31, 2017:		
Common units issued in connection with ATM program	12,865,371	\$ 356.0
Common units issued in connection with DRIP and EUPP	3,440,559	92.8
Total common units issued for quarter	<u>16,305,930</u>	<u>448.8</u>
Three months ended June 30, 2017:		
Common units issued in connection with ATM program	7,991,635	215.8
Common units issued in connection with DRIP and EUPP	3,595,122	92.6
Total common units issued for quarter	<u>11,586,757</u>	<u>308.4</u>
Total common units issued during the six months ended June 30, 2017	<u><u>27,892,687</u></u>	<u><u>\$ 757.2</u></u>

### ***ATM Program***

We have a registration statement on file with the SEC covering the issuance of up to \$1.89 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 in connection with our ATM program. After taking into account the aggregate sales price of common units sold under the ATM program through June 30, 2017, we have the capacity to issue additional common units under the ATM program up to an aggregate sales price of \$864.4 million.

### ***DRIP and EUPP***

We also have registration statements on file with the SEC collectively authorizing the issuance of up to 240,000,000 of our common units in connection with our DRIP. After taking into account the number of common units issued under the DRIP through June 30, 2017, we have the capacity to issue an additional 92,455,606 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 EUPP. After taking into account the number of common units issued under the EUPP through June 30, 2017, we have the capacity to issue an additional 6,032,683 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, 2017 were used to temporarily reduce amounts outstanding under EPO’s commercial paper program and for general company purposes.

For additional information regarding our issuance of common units and related registration statements, see Note 8 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

### ***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 margin requirements change.

At June 30, 2017 and December 31, 2016, our restricted cash amounts were \$35.4 million and \$354.5 million, respectively. The balance of restricted cash decreased since December 31, 2016 primarily due to the settlement of derivative instruments related to marketing positions during the first quarter of 2017. For information regarding our derivative instruments and hedging activities, see Note 12 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, 2017, 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.

	<b>For the Six Months Ended June 30,</b>	
	<b>2017</b>	<b>2016</b>
Net cash flows provided by operating activities	\$ 2,334.9	\$ 1,845.2
Cash used in investing activities	979.5	2,238.6
Cash provided by (used in) financing activities	(1,389.9)	487.9

Net cash flows provided by operating activities are largely dependent on earnings from our consolidated business activities. We operate in the midstream energy industry, which includes gathering, transporting, processing, fractionating and storing natural gas, NGLs, crude oil, petrochemical and refined products. As such, changes in the prices of hydrocarbon products and in the relative price levels among hydrocarbon products could have a material adverse effect on our financial position, results of operations and cash flows. Changes in prices may impact demand for hydrocarbon products, which in turn may impact production, demand and the volumes of products for which we provide services. In addition, decreases in demand may be caused by other factors, including prevailing economic conditions, reduced demand by consumers for the end products made with hydrocarbon products, increased competition, adverse weather conditions and government regulations affecting prices and production levels. We may also incur credit and price risk to the extent customers do not fulfill their obligations to us in connection with our marketing of natural gas, NGLs, propylene, refined products and/or crude oil and long-term take-or-pay agreements. 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 2016 Form 10-K.

### ***Comparison of Six Months Ended June 30, 2017 with Six Months Ended June 30, 2016***

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, 2017 increased \$489.7 million when compared to the six months ended June 30, 2016. The increase in cash provided by operating activities was primarily due to:

- a \$376.7 million period-to-period increase in cash primarily due to the timing of cash receipts and payments related to operations; and
- a \$103.0 million increase in cash attributable to higher partnership income in the six months ended June 30, 2017 compared to the six months ended June 30, 2016 (after adjusting our \$196.8 million period-to-period increase in net income for changes in the non-cash items identified on our Unaudited Condensed Statements of Consolidated Cash Flows).

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 for investing activities in the six months ended June 30, 2017 decreased \$1.26 billion when compared to the same period in 2016 primarily due to:

- a \$743.7 million period-to-period decrease in capital spending for consolidated property, plant and equipment, net of contributions in aid of construction costs (see “Capital Spending” within this Part I, Item 2 for additional information regarding our capital spending program);
- a \$675.8 million period-to-period beneficial change in restricted cash, which was an outflow of \$356.7 million in the first six months of 2016 compared to a cash inflow of \$319.1 million during the first six months of 2017; and
- \$191.4 million of cash used for the Azure acquisition.

*Financing activities.* Cash used in financing activities for the six months ended June 30, 2017 was \$1.39 billion compared to cash provided by financing activities of \$487.9 million for the six months ended June 30, 2016. The \$1.88 billion period-to-period change in cash flow from financing activities was primarily due to:

- a \$1.13 billion period-to-period decrease in net cash proceeds from the issuance of common units. We issued an aggregate 27,892,687 common units, which generated \$757.2 million of net cash proceeds, in connection with our ATM program, DRIP and EUPP during the six months ended June 30, 2017. This compares to an aggregate 79,029,881 common units we issued in connection with these programs and plans during the same period in 2016, which collectively generated \$1.89 billion of net cash proceeds;
- a \$580.1 million period-to-period change in our consolidated debt obligations primarily due to the issuance of \$1.25 billion and repayment of \$750.0 million in principal amount of senior notes during the six months ended June 30, 2016 compared to no such issuances or repayments during the six months ended June 30, 2017. In addition, net repayments to EPO’s commercial paper program increased \$86.6 million period-to-period; and
- a \$147.3 million period-to-period increase in cash distributions paid to limited partners during the six months ended June 30, 2017 when compared to the same period in 2016. 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.

#### ***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.

We measure available cash by reference to “distributable cash flow,” which is a non-GAAP liquidity measure. 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. 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.

Based on the level of available cash, management proposes a quarterly cash distribution rate to the Board of Enterprise GP, which has sole authority in approving such matters. Unlike several other 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 incentive distribution rights or other equity interests.

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, which is the most comparable GAAP measure. For a discussion of net cash flows provided by operating activities, see the previous section titled “Cash Flows from Operating, Investing and Financing Activities” within this Item 2.

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,	
	2017	2016	2017	2016
Net income attributable to limited partners (1)	\$ 653.7	\$ 558.5	\$ 1,414.4	\$ 1,219.7
<i>Adjustments to GAAP net income attributable to limited partners to derive non-GAAP distributable cash flow:</i>				
Add depreciation, amortization and accretion expenses	406.5	381.3	808.8	763.4
Add non-cash asset impairment and related charges	14.0	20.6	25.2	22.3
Add net losses attributable to asset sales	0.3	1.7	--	6.6
Add cash proceeds from asset sales (2)	1.2	14.5	3.2	27.9
Add or subtract changes in fair market value of derivative instruments	(23.6)	48.2	(43.9)	68.3
Add changes in fair value of Liquidity Option Agreement (3)	18.6	23.3	24.1	21.1
Add cash distributions received from unconsolidated affiliates (4)	127.4	118.7	229.9	234.5
Subtract equity in income of unconsolidated affiliates	(107.0)	(76.4)	(201.8)	(177.5)
Subtract sustaining capital expenditures (5)	(62.3)	(58.4)	(110.3)	(117.7)
Add deferred income tax expense or subtract benefit, as applicable	0.6	0.2	0.7	4.3
Other, net	22.5	7.5	30.2	20.4
Distributable cash flow	\$ 1,051.9	\$ 1,039.7	\$ 2,180.5	\$ 2,093.3
Total cash distributions paid to limited partners with respect to period	\$ 906.5	\$ 841.0	\$ 1,799.3	\$ 1,666.4
Cash distributions per unit declared by Enterprise GP with respect to period (6)	\$ 0.420	\$ 0.400	\$ 0.835	\$ 0.795
Total distributable cash flow retained by partnership with respect to period (7)	\$ 145.4	\$ 198.7	\$ 381.2	\$ 426.9
Distribution coverage ratio (8)	1.2x	1.2x	1.2x	1.3x

(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 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 the Liquidity Option Agreement, see Note 14 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

(4) Reflects both distributions received on earnings from unconsolidated affiliates and those attributable to a return of capital from unconsolidated affiliates. For information regarding our unconsolidated affiliates, see Note 5 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

(5) Sustaining capital expenditures are presented on an accrual basis.

(6) See Note 8 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 is 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.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2017	2016	2017	2016
Net cash flows provided by operating activities	\$ 1,459.3	\$ 945.5	\$ 2,334.9	\$ 1,845.2
<i>Adjustments to reconcile net cash flows provided by operating activities to distributable cash flow:</i>				
Subtract sustaining capital expenditures	(62.3)	(58.4)	(110.3)	(117.7)
Add cash proceeds from asset sales	1.2	14.5	3.2	27.9
Net effect of changes in operating accounts	(370.9)	108.2	(82.1)	294.6
Other, net	24.6	29.9	34.8	43.3
Distributable cash flow	\$ 1,051.9	\$ 1,039.7	\$ 2,180.5	\$ 2,093.3

## 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 well positioned to continue to expand our network 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, Northeast and U.S. Gulf Coast 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.

We began commercial service on approximately \$230 million of major growth capital projects during the six months ended June 30, 2017 including expansions related to our propylene pipeline system and Beaumont refined products terminal. In addition, we have approximately \$9.0 billion of growth capital projects scheduled to be completed by 2020 including our PDH and iBDH facilities, the Midland-to-Sealy segment of our Midland-to-ECHO Pipeline System, the Shin Oak NGL pipeline, our ninth NGL fractionator in Mont Belvieu and completion of joint venture-owned dock infrastructure in Corpus Christi designed to accommodate crude oil volumes.

For the full year of 2017, we currently expect to invest in the range of \$2.8 billion to \$3.0 billion for growth capital projects, including the \$191.4 million we paid in connection with the Azure acquisition, and approximately \$250 million for sustaining capital expenditures. Our forecast of capital spending for 2017 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 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 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.



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

	<b>For the Six Months Ended June 30,</b>	
	<b>2017</b>	<b>2016</b>
<b>Capital spending for property, plant and equipment, net:</b> (1)		
Growth capital projects (2)	\$ 1,003.6	\$ 1,729.1
Sustaining capital projects (3)	109.5	127.7
<b>Investments in unconsolidated affiliates</b>	24.1	92.4
<b>Cash used for Azure acquisition</b>	191.4	--
<b>Total capital spending</b>	<b>\$ 1,328.6</b>	<b>\$ 1,949.2</b>

- (1) 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 \$29.6 million and \$23.6 million for the six months ended June 30, 2017 and 2016, respectively. Growth and sustaining capital amounts presented in the table above are presented on a cash basis and net of related contributions in aid of construction costs.
- (2) 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.
- (3) 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, 2017 involved projects at our Mont Belvieu complex as well as projects to support crude oil, natural gas and NGL production from the Permian Basin. Fluctuations in spending for sustaining capital projects are explained in large part by the timing and cost of pipeline integrity and similar projects.

#### ***Comparison of Six Months Ended June 30, 2017 with Six Months Ended June 30, 2016***

Total capital spending decreased \$620.6 million period-to-period primarily due to reduced spending on growth capital projects, which accounted for a \$725.5 million decrease, partially offset by the \$191.4 million we paid in connection with the Azure acquisition. Of the period-to-period decrease in growth capital spending, the significant elements are as follows:

- Growth capital spending at our Mont Belvieu complex decreased \$284.0 million period-to-period primarily due to lower spending for our PDH facility as it nears completion. We expect the PDH facility, which is currently in the commissioning stage, to begin operations during the third quarter of 2017;
- Growth capital spending for crude oil assets at our EHT, Beaumont Marine West and ECHO terminals decreased a combined \$160.5 million period-to-period primarily due to the completion of new storage tanks and related assets at these facilities during 2016;
- Growth capital spending at EHT for LPG export-related expansion projects and at our Morgan's Point Ethane Export Terminal decreased a combined \$147.5 million period-to-period. In September 2016, we placed our Morgan's Point Ethane Export Terminal into service;
- Growth capital spending for our ethane header system between Corpus Christi, Texas and the Mississippi River in Louisiana decreased \$77.1 million period-to-period;
- Growth capital spending at our natural gas processing plants in Louisiana and Mississippi decreased \$35.0 million period-to-period; and
- Growth capital spending for expansion projects on our EFS Midstream system in South Texas decreased \$31.9 million period-to-period.

We are in various stages of completion on multiple projects to support crude oil, natural gas and NGL production in the Permian Basin, including our South Eddy and Orla natural gas processing plants and related pipelines, Shin Oak NGL Pipeline and Midland-to-ECHO Pipeline System. Overall, growth capital spending for projects to support Permian Basin production increased \$55.7 million period-to-period.

Investments in unconsolidated affiliates decreased \$68.3 million period-to-period primarily due to reduced spending on joint venture-owned crude oil pipelines and dock infrastructure, which accounted for a \$33.5 million decrease, and completion of our Waha natural gas processing plant in August 2016, which accounted for an additional \$29.2 million decrease.

### **Critical Accounting Policies and Estimates**

A discussion of our critical accounting policies and estimates is included in our 2016 Form 10-K. The following types of 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**

#### ***Contractual Obligations***

Our consolidated principal debt obligations at June 30, 2017 were approximately \$23.58 billion compared to \$23.90 billion at December 31, 2016. For information regarding the scheduled maturities of such debt, see “Liquidity and Capital Resources – Consolidated Debt” within this Part I, Item 2. See Note 7 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.

#### ***Recent Accounting Developments***

In May 2014, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Codification 606, *Revenues from Contracts with Customers* (“ASC 606”). The new accounting standard, along with its related amendments, replaces the current rules-based U.S. GAAP governing revenue recognition with a principles-based approach. We plan to adopt the new standard on January 1, 2018.

In February 2016, the FASB issued ASC 842, *Leases* (“ASC 842”), which requires substantially all leases (with the exception of leases with a term of one year or less) to be recorded on the balance sheet using a method referred to as the right-of-use asset approach. We plan to adopt the new standard on January 1, 2019.

For additional information regarding these new accounting standards, see Note 2 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

### ***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.***

### **General**

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.

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 2016 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 economic value (or 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 economic 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 economic 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.

In addition, the fair value amounts presented in the sensitivity analysis tables below do not reflect any rule changes made by certain exchanges (e.g., the Chicago Mercantile Exchange) that may impact the financial statement or disclosure presentation for a derivative instrument since such rule changes have no impact on the underlying contractual terms of the derivative instrument itself, including the timing or price of the ultimate settlement.

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 12 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.

## Commodity Hedging Activities

The prices of natural gas, NGLs, crude oil, petrochemicals and refined 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, 2017 (volume measures as noted):

Derivative Purpose	Volume (1)		Accounting Treatment
	Current (2)	Long-Term (2)	
<b>Derivatives designated as hedging instruments:</b>			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction (Bcf)	16.4	n/a	Cash flow hedge
Forecasted sales of NGLs (MMBbls)	2.3	n/a	Cash flow hedge
Natural gas marketing:			
Forecasted purchases of natural gas for fuel (Bcf)	3.0	n/a	Cash flow hedge
Natural gas storage inventory management activities (Bcf)	3.5	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	70.4	0.1	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	85.3	0.9	Cash flow hedge
NGLs inventory management activities (MMBbls)	1.4	n/a	Fair value hedge
Refined products marketing:			
Forecasted sales of refined products (MMBbls)	0.1	n/a	Cash flow hedge
Refined products inventory management activities (MMBbls)	4.8	n/a	Fair value hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	7.6	n/a	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	12.7	n/a	Cash flow hedge
<b>Derivatives not designated as hedging instruments:</b>			
Natural gas risk management activities (Bcf) (3,4)	169.2	20.4	Mark-to-market
NGL risk management activities (MMBbls) (4)	9.7	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (4)	35.3	17.5	Mark-to-market

- (5) 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.
- (6) 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 2018, December 2017 and March 2020, respectively.
- (7) Current and long-term volumes include 61.0 Bcf and 9.3 Bcf, respectively, of physical derivative instruments that are predominantly priced at a marked-based index plus a premium or minus a discount related to location differences.
- (8) Reflects the use of derivative instruments to manage risks associated with transportation, processing and storage assets.

At June 30, 2017, 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 derivative instruments and related contracts.
- The objective of our natural gas processing hedging program is to hedge an amount of earnings associated with these activities. We achieve this objective by executing fixed-price sales for a portion of our expected equity NGL production using derivative instruments and related contracts. 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 using derivative instruments and related contracts.
- 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 derivative instruments and related contracts.

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

Scenario	Resulting Classification	Portfolio Fair Value at		
		December 31, 2016	June 30, 2017	July 14, 2017
Fair value assuming no change in underlying commodity prices	Asset (Liability)	\$ (5.3)	\$ (2.8)	\$ (0.9)
Fair value assuming 10% increase in underlying commodity prices	Asset (Liability)	(9.7)	(5.9)	(3.8)
Fair value assuming 10% decrease in underlying commodity prices	Asset (Liability)	(0.9)	0.3	2.1

The following table shows the effect of hypothetical price movements (a sensitivity analysis) on the estimated economic 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, 2016	June 30, 2017	July 14, 2017
Fair value assuming no change in underlying commodity prices	Asset (Liability)	\$ (150.3)	\$ 29.3	\$ 14.3
Fair value assuming 10% increase in underlying commodity prices	Asset (Liability)	(227.7)	(16.3)	(32.7)
Fair value assuming 10% decrease in underlying commodity prices	Asset (Liability)	(73.0)	75.0	61.3

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

Scenario	Resulting Classification	Portfolio Fair Value at		
		December 31, 2016	June 30, 2017	July 14, 2017
Fair value assuming no change in underlying commodity prices	Asset (Liability)	\$ (42.4)	\$ 7.1	\$ 8.3
Fair value assuming 10% increase in underlying commodity prices	Asset (Liability)	(80.0)	(26.0)	(23.7)
Fair value assuming 10% decrease in underlying commodity prices	Asset (Liability)	(4.7)	40.1	40.2

### 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 may be used in controlling our overall cost of capital associated with such borrowings. The composition of our derivative instrument portfolios may change depending on our hedging requirements.

With respect to the tabular data below, each portfolio's estimated economic 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 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, 2017 (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 1.66%	Fair value hedge

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

Scenario	Resulting Classification	Interest Rate Swap Portfolio Fair Value at		
		December 31, 2016	June 30, 2017	July 14, 2017
Fair value assuming no change in underlying interest rates	Asset (Liability)	\$ (0.8)	\$ (1.6)	\$ (1.4)
Fair value assuming 10% increase in underlying interest rates	Asset (Liability)	(2.0)	(2.4)	(2.2)
Fair value assuming 10% decrease in underlying interest rates	Asset (Liability)	0.4	(0.8)	(0.6)

The following table summarizes our portfolio of 30-year forward starting swaps outstanding at June 30, 2017. Forward starting swaps hedge the expected underlying benchmark interest rates related to future issuances of debt.

Hedged Transaction	Number and Type of Derivatives Outstanding	Notional Amount	Expected Settlement Date	Average Rate Locked	Accounting Treatment
Future long-term debt offering	4 forward starting swaps	\$275.0	5/2018	2.02%	Cash flow hedge

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

Scenario	Resulting Classification	Forward Starting Swap Portfolio Fair Value at		
		December 31, 2016	June 30, 2017	July 14, 2017
Fair value assuming no change in underlying interest rates	Asset (Liability)	\$ 36.2	\$ 31.7	\$ 33.8
Fair value assuming 10% increase in underlying interest rates	Asset (Liability)	49.3	44.7	46.9
Fair value assuming 10% decrease in underlying interest rates	Asset (Liability)	22.1	17.7	19.7

#### 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 (i) A. James Teague, our general partner's Chief Executive Officer, (ii) W. Randall Fowler, our general partner's President, and (iii) Bryan F. Bulawa, our general partner's Chief Financial Officer, of the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 of the Securities Exchange Act of 1934. Mr. Teague is our principal executive officer and Messrs. Fowler and Bulawa represent our principal financial officers. Based on this evaluation, as of the end of the period covered by this quarterly report, Messrs. Teague, Fowler and 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**

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 2017, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

### **Section 302 and 906 Certifications**

The required certifications of Messrs. Teague, Fowler and 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 14 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 risks described under “Risk Factors” set forth in Part I, Item 1A of our 2016 Form 10-K, in addition to other information in such annual report. The risk factors set forth in our 2016 Form 10-K are important factors that could cause our actual results to differ materially from those contained in any written or oral forward-looking statements made by us or on our behalf.

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

The following table summarizes our repurchase activity during the six months ended June 30, 2017 in connection with the vesting of restricted and phantom unit awards:

<b>Period</b>	<b>Total Number of Units Purchased</b>	<b>Average Price Paid per Unit</b>	<b>Total Number of Units Purchased as Part of Publicly Announced Plans</b>	<b>Maximum Number of Units That May Yet Be Purchased Under the Plans</b>
Vesting of restricted unit awards:				
February 2017 (1)	225,751	\$ 28.77	--	--
May 2017 (2)	742	\$ 27.45	--	--
Vesting of phantom unit awards:				
February 2017 (3)	720,393	\$ 28.82	--	--
March 2017 (4)	147	\$ 27.58	--	--
May 2017 (5)	39,653	\$ 27.40	--	--

- (1) Of the 665,920 restricted common unit awards that vested in February 2017 and converted to common units, 225,751 units were sold back to us by employees to cover related withholding tax requirements.
- (2) Of the 2,550 restricted common unit awards that vested in May 2017 and converted to common units, 742 units were sold back to us by employees to cover related withholding tax requirements.
- (3) Of the 2,233,617 phantom unit awards that vested in February 2017 and converted to common units, 720,393 units were sold back to us by employees to cover related withholding tax requirements.
- (4) Of the 450 phantom unit awards that vested in March 2017 and converted to common units, 147 units were sold back to us by employees to cover related withholding tax requirements.
- (5) Of the 117,369 phantom unit awards that vested in May 2017 and converted to common units, 39,653 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 U.S. 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 Enterprise GP in October 2014, as the designee of Marquard & Bahls AG (“M&B”), in connection with our acquisition of Oiltanking Partners, L.P. (“Oiltanking”). Dr. Flach is also the Chief Executive Officer of M&B and a member of the M&B executive board.



M&B owns and controls Oiltanking GmbH, which in turn owns a joint venture interest in the Exir Chemical Terminal (“ECT”) in Iran via its wholly owned affiliates Oiltanking Iran GmbH (formerly named Oiltanking Odfjell GmbH) and OMEA GmbH. This interest results from an investment dating back to 2002. Oiltanking GmbH currently has the contractual right to vote for the appointment of two members 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 U.S., 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.**

<b>Exhibit Number</b>	<b>Exhibit*</b>
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 Amendment No. 1 to Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products Holdings LLC, dated effective as of April 26, 2017 (incorporated by reference to Exhibit 3.1 to Form 8-K filed May 2, 2017).
- 3.10 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).

- 3.11 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).
- 3.12 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 14, 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 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).
- 4.8 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).
- 4.9 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).
- 4.10 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).
- 4.11 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).
- 4.12 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).

- 4.13 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).
- 4.14 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).
- 4.15 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).
- 4.16 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).
- 4.17 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).
- 4.18 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).
- 4.19 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).
- 4.20 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).
- 4.21 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).
- 4.22 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).
- 4.23 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).
- 4.24 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).
- 4.25 Twenty-Eighth Supplemental Indenture, dated as of April 13, 2016, 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 April 13, 2016).
- 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 5.75% Series B Senior Notes due 2035 with attached Guarantee (incorporated by reference to Exhibit 4.32 to Form 10-Q filed November 4, 2005).
- 4.29 Form of Junior Subordinated Note, including Guarantee (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006).
- 4.30 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).
- 4.31 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).
- 4.32 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).
- 4.33 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).
- 4.34 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).
- 4.35 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).
- 4.36 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).
- 4.37 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).
- 4.38 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).
- 4.39 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).
- 4.40 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).
- 4.41 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).
- 4.42 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).
- 4.43 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).
- 4.44 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).

- 4.45 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).
- 4.46 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).
- 4.47 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).
- 4.48 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).
- 4.49 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).
- 4.50 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).
- 4.51 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).
- 4.52 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).
- 4.53 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).
- 4.54 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).
- 4.55 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).
- 4.56 Form of Global Note representing \$575.0 million principal amount of 2.85% Senior Notes due 2021 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed April 13, 2016).
- 4.57 Form of Global Note representing \$575.0 million principal amount of 3.95% Senior Notes due 2027 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed April 13, 2016).
- 4.58 Form of Global Note representing \$100.0 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 April 13, 2016).
- 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 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 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 October 1, 2014).
- 12.1# Computation of ratio of earnings to fixed charges for the six months ended June 30, 2017 and each of the years ended December 31, 2016, 2015, 2014, 2013 and 2012.
- 31.1# Sarbanes-Oxley Section 302 certification of A. James Teague for Enterprise Products Partners L.P.'s quarterly report on Form 10-Q for the six months ended June 30, 2017.
- 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, 2017.
- 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, 2017.
- 32.1# Sarbanes-Oxley Section 906 certification of A. James Teague for Enterprise Products Partners L.P.'s quarterly report on Form 10-Q for the six months ended June 30, 2017.
- 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, 2017.
- 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, 2017.
- 101.CAL# XBRL Calculation Linkbase Document
- 101.DEF# XBRL Definition Linkbase Document
- 101.INS# XBRL Instance Document
- 101.LAB# XBRL Labels Linkbase Document
- 101.PRE# XBRL Presentation Linkbase Document
- 101.SCH# XBRL Schema Document

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

\*\*\* Identifies management contract and compensatory plan arrangements.

# Filed with this report.



**SIGNATURES**

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on August 4, 2017.

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

By: Enterprise Products Holdings LLC, as General Partner

By: /s/ R. Daniel Boss  
Name: R. Daniel Boss  
Title: Senior Vice President-Accounting and Risk Control  
of the General Partner

By: /s/ Michael W. Hanson  
Name: Michael W. Hanson  
Title: Vice President and Principal Accounting Officer  
of the General Partner