UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2016

OR

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

For the transition period from ___ to ___.

Commission file number: 1-14323

ENTERPRISE PRODUCTS PARTNERS L.P.

(Exact Name of Registrant as Specified in Its Charter)

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

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

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

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

Yes ☑ No ☐

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

Yes ☑ No ☐

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

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

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

Yes ☐ No ☑

There were 2,104,197,364 common units of Enterprise Products Partners L.P. outstanding at the close of business on October 31, 2016. 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)

	September 30, 2016	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$ 57.1	$ 19.0
Restricted cash	277.3	15.9
Accounts receivable – trade, net of allowance for doubtful accounts of $14.0 at September 30, 2016 and $12.1 at December 31, 2015	2,944.1	2,569.9
Accounts receivable – related parties	1.7	1.2
Inventories	1,762.5	1,038.1
Derivative assets	241.4	258.6
Prepaid and other current assets	457.5	395.6
Total current assets	5,741.6	4,298.3
Property, plant and equipment, net	33,119.4	32,034.7
Investments in unconsolidated affiliates	2,687.2	2,628.5
Intangible assets, net of accumulated amortization of $1,365.9 at September 30, 2016 and $1,235.8 at December 31, 2015 (see Note 6)	3,907.2	4,037.2
Goodwill (see Note 6)	5,745.2	5,745.2
Other assets	57.8	58.3
Total assets	$ 51,258.4	$ 48,802.2
LIABILITIES AND EQUITY		
Current liabilities:		
Current maturities of debt (see Note 7)	$ 2,838.1	$ 1,863.9
Accounts payable – trade	453.7	860.1
Accounts payable – related parties	97.7	84.1
Accrued product payables	3,087.5	2,484.4
Accrued liability related to EFS Midstream acquisition	--	993.2
Accrued interest	202.7	352.1
Derivative liabilities	464.2	140.6
Other current liabilities	424.4	388.2
Total current liabilities	7,568.3	7,166.6
Long-term debt (see Note 7)	21,121.2	20,676.9
Deferred tax liabilities	51.6	46.1
Other long-term liabilities	478.6	411.5
Commitments and contingencies (see Note 14)		
Equity:		
Partners' equity:		
Limited partners:		
Common units (2,102,796,228 units outstanding at September 30, 2016 and 2,012,553,024 units outstanding at December 31, 2015)	22,127.9	20,514.3
Accumulated other comprehensive loss	(308.7)	(219.2)
Total partners' equity	21,819.2	20,295.1
Noncontrolling interests	219.5	206.0
Total equity	22,038.7	20,501.1
Total liabilities and equity	$ 51,258.4	$ 48,802.2

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	**2015**	**2016**	**2015**
Revenues:				
Third parties	$ 5,904.7	$ 6,294.0	$ 16,499.0	$ 20,845.6
Related parties	15.7	13.9	44.5	27.3
Total revenues (see Note 9)	5,920.4	6,307.9	16,543.5	20,872.9
Costs and expenses:				
Operating costs and expenses:				
Third parties	4,781.2	5,167.9	13,199.4	17,642.6
Related parties	284.5	284.7	835.4	783.9
Total operating costs and expenses	5,065.7	5,452.6	14,034.8	18,426.5
General and administrative costs:				
Third parties	15.0	20.8	35.9	57.9
Related parties	27.0	28.2	85.1	85.3
Total general and administrative costs	42.0	49.0	121.0	143.2
Total costs and expenses (see Note 9)	5,107.7	5,501.6	14,155.8	18,569.7
Equity in income of unconsolidated affiliates	92.3	103.1	269.8	302.5
Operating income	905.0	909.4	2,657.5	2,605.7
Other income (expense):				
Interest expense	(250.9)	(243.7)	(735.6)	(723.2)
Change in fair market value of Liquidity Option Agreement (see Note 14)	(6.9)	(4.3)	(28.0)	(15.8)
Other, net	0.7	1.8	2.5	2.6
Total other expense, net	(257.1)	(246.2)	(761.1)	(736.4)
Income before income taxes	647.9	663.2	1,896.4	1,869.3
Provision for income taxes	(4.8)	(5.5)	(13.1)	(4.4)
Net income	643.1	657.7	1,883.3	1,864.9
Net income attributable to noncontrolling interests (see Note 8)	(8.5)	(8.4)	(29.0)	(28.5)
Net income attributable to limited partners	$ 634.6	$ 649.3	$ 1,854.3	$ 1,836.4
Earnings per unit: (see Note 10)				
Basic earnings per unit	$ 0.30	$ 0.33	$ 0.89	$ 0.94
Diluted earnings per unit	$ 0.30	$ 0.32	$ 0.89	$ 0.92

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
Net income	$ 643.1	$ 657.7	$ 1,883.3	$ 1,864.9
Other comprehensive income (loss):				
Cash flow hedges:				
Commodity derivative instruments:				
Changes in fair value of cash flow hedges	22.7	85.8	(52.2)	112.3
Reclassification of gains to net income	(26.9)	(46.8)	(48.7)	(128.1)
Interest rate derivative instruments:				
Changes in fair value of cash flow hedges	(6.9)	--	(16.3)	--
Reclassification of losses to net income	9.4	8.9	27.8	26.3
Total cash flow hedges	(1.7)	47.9	(89.4)	10.5
Other	--	--	(0.1)	0.4
Total other comprehensive income (loss)	(1.7)	47.9	(89.5)	10.9
Comprehensive income	641.4	705.6	1,793.8	1,875.8
Comprehensive income attributable to noncontrolling interests	(8.5)	(8.4)	(29.0)	(28.5)
Comprehensive income attributable to limited partners	$ 632.9	$ 697.2	$ 1,764.8	$ 1,847.3

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

	For the Nine Months Ended September 30,	
	2016	2015
Operating activities:		
Net income	$ 1,883.3	$ 1,864.9
Reconciliation of net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	1,155.3	1,147.7
Asset impairment charges (see Note 12)	22.0	139.1
Loss due to Pascagoula fire (see Note 4)	7.1	--
Equity in income of unconsolidated affiliates	(269.8)	(302.5)
Distributions received on earnings from unconsolidated affiliates	281.6	362.4
Net losses (gains) attributable to asset sales	(2.3)	14.7
Gains on early extinguishment of debt	--	(1.4)
Deferred income tax expense (benefit)	5.3	(13.3)
Change in fair market value of derivative instruments	42.1	(7.7)
Change in fair market value of Liquidity Option Agreement (see Note 14)	28.0	15.8
Net effect of changes in operating accounts (see Note 15)	(489.7)	(627.9)
Other operating activities	(3.9)	(0.6)
Net cash flows provided by operating activities	2,659.0	2,591.2
Investing activities:		
Capital expenditures	(2,443.9)	(2,630.5)
Contributions in aid of construction costs	34.1	11.4
Increase in restricted cash	(261.4)	(46.2)
Cash used for business combinations, net of cash received	(1,000.0)	(1,045.1)
Investments in unconsolidated affiliates	(119.9)	(130.7)
Distributions received for return of capital from unconsolidated affiliates	51.9	--
Proceeds from asset sales	43.9	1,537.3
Other investing activities	(0.4)	(4.4)
Cash used in investing activities	(3,695.7)	(2,308.2)
Financing activities:		
Borrowings under debt agreements	50,183.8	17,113.7
Repayments of debt	(48,776.5)	(16,139.2)
Debt issuance costs	(10.5)	(23.9)
Cash distributions paid to limited partners (see Note 8)	(2,448.3)	(2,185.1)
Cash payments made in connection with distribution equivalent rights	(8.5)	(5.6)
Cash distributions paid to noncontrolling interests	(35.7)	(33.2)
Cash contributions from noncontrolling interests	20.1	37.4
Net cash proceeds from the issuance of common units	2,170.4	1,011.4
Other financing activities	(20.0)	(52.4)
Cash provided by (used in) financing activities	1,074.8	(276.9)
Net change in cash and cash equivalents	38.1	6.1
Cash and cash equivalents, January 1	19.0	74.4
Cash and cash equivalents, September 30	$ 57.1	$ 80.5

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)

	Partners' Equity			
	Limited Partners	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
Balance, December 31, 2015	$ 20,514.3	$ (219.2)	$ 206.0	$ 20,501.1
Net income	1,854.3	--	29.0	1,883.3
Cash distributions paid to limited partners	(2,448.3)	--	--	(2,448.3)
Cash payments made in connection with distribution equivalent rights	(8.5)	--	--	(8.5)
Cash distributions paid to noncontrolling interests	--	--	(35.7)	(35.7)
Cash contributions from noncontrolling interests	--	--	20.1	20.1
Net cash proceeds from the issuance of common units	2,170.4	--	--	2,170.4
Amortization of fair value of equity-based awards	67.7	--	--	67.7
Cash flow hedges	--	(89.4)	--	(89.4)
Other	(22.0)	(0.1)	0.1	(22.0)
Balance, September 30, 2016	$ 22,127.9	$ (308.7)	$ 219.5	$ 22,038.7

	Partners' Equity			
	Limited Partners	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
Balance, December 31, 2014	$ 18,304.8	$ (241.6)	$ 1,629.0	$ 19,692.2
Net income	1,836.4	--	28.5	1,864.9
Cash distributions paid to limited partners	(2,185.1)	--	--	(2,185.1)
Cash payments made in connection with distribution equivalent rights	(5.6)	--	--	(5.6)
Cash distributions paid to noncontrolling interests	--	--	(33.2)	(33.2)
Cash contributions from noncontrolling interests	--	--	37.4	37.4
Common units issued in connection with Step 2 of Oiltanking acquisition	1,408.7	--	(1,408.7)	--
Removal of noncontrolling interests in connection with sale of Offshore Business	--	--	(62.1)	(62.1)
Net cash proceeds from the issuance of common units	1,011.4	--	--	1,011.4
Amortization of fair value of equity-based awards	72.9	--	--	72.9
Cash flow hedges	--	10.5	--	10.5
Other	(50.7)	0.4	(0.1)	(50.4)
Balance, September 30, 2015	$ 20,392.8	$ (230.7)	$ 190.8	$ 20,352.9

See 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 32.6% of our limited partner interests at September 30, 2016.

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

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

References to "Offshore Business" refer to the Gulf of Mexico operations we sold to Genesis Energy, L.P. ("Genesis") in July 2015.

References to "EFS Midstream" mean EFS Midstream LLC, which we acquired in July 2015 from affiliates of Pioneer Natural Resources Company ("Pioneer") and Reliance Industries Limited ("Reliance").

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 liquid ("NGL") 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 import and export terminals (including liquefied petroleum gas, or "LPG"); crude oil gathering, transportation, storage and terminals; petrochemical and refined products transportation, storage and terminals, and related services; and a marine transportation business that operates primarily on the U.S. inland and Intracoastal Waterway systems. Our assets currently include approximately 49,000 miles of pipelines; 250 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.

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 historical operations are reported under five business segments: (i) NGL Pipelines & Services, (ii) Crude Oil Pipelines & Services, (iii) Natural Gas Pipelines & Services, (iv) Petrochemical & Refined Products Services and (v) Offshore Pipelines & Services. On July 24, 2015, we completed the sale of our Offshore Business, which primarily consisted of our Offshore Pipelines & Services segment. Our consolidated financial statements reflect ownership of the Offshore Business through July 24, 2015. See Note 9 for additional information regarding our business segments.

As a result of our acquisition of the member interests of EFS Midstream effective July 1, 2015, we began consolidating the financial statements of EFS Midstream as of that date.

Effective January 1, 2016, we applied the provisions of Accounting Standard Update ("ASU") 2015-03, *Simplifying the Presentation of Debt Issuance Costs*, which requires bond issuance costs to be presented on the balance sheet as a deduction from the carrying value of the associated debt. The guidance was applied on a retrospective basis; therefore, we adjusted our December 31, 2015 consolidated balance sheet to reflect the reclassification of $14.7 million of bond issuance costs from prepaid and other current assets and $135.1 million from other assets to reduce the carrying amount of long-term debt by an aggregate $149.8 million. See Note 7 for additional information regarding our long-term debt.

Note 2. General Accounting and Disclosure Matters

Our results of operations for the three and nine months ended September 30, 2016 are not necessarily indicative of results expected for the full year of 2016. 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, 2015 (the "2015 Form 10-K") filed with the SEC on February 26, 2016.

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.

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.

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 September 30, 2016 and December 31, 2015, our restricted cash amounts were $277.3 million and $15.9 million, respectively. The balance at September 30, 2016 consisted of initial margin requirements of $48.9 million and variation margin requirements of $228.4 million. The initial margin requirements will be returned to us as the related derivative instruments are settled. Our variation margin requirements increased by $248.7 million since December 31, 2015 primarily due to higher forward commodity prices for NGLs and related hydrocarbons during 2016 relative to our short financial derivative positions in these products. See Note 12 for information regarding our derivative instruments and hedging activities.

Note 3. Inventories

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

	September 30, 2016	December 31, 2015
NGLs	$ 1,202.4	$ 639.9
Petrochemicals and refined products	230.4	148.0
Crude oil	299.3	222.1
Natural gas	30.4	28.1
Total	$ 1,762.5	$ 1,038.1

Our inventories, and associated working capital commitments, have increased significantly since December 31, 2015 primarily due to our marketing groups taking advantage of contango opportunities using our storage assets. We expect to gradually settle these inventory positions (valued at approximately $1 billion) through the first quarter of 2017, with a corresponding decrease in working capital commitments and related debt.

Due to fluctuating commodity prices, we recognize lower of cost or market adjustments when the carrying value of our available-for-sale inventories exceeds their net realizable value. The following table presents our total cost of sales amounts and lower of cost or market adjustments for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
Cost of sales (1)	$ 4,088.6	$ 4,419.9	$ 11,135.6	$ 15,355.9
Lower of cost or market adjustments within cost of sales	1.5	2.1	7.6	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.

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:

	Estimated Useful Life in Years	September 30, 2016	December 31, 2015
Plants, pipelines and facilities (1)	3-45 (5)	$ 34,752.7	$ 32,525.0
Underground and other storage facilities (2)	5-40 (6)	3,309.2	3,000.5
Transportation equipment (3)	3-10	162.9	159.9
Marine vessels (4)	15-30	792.0	769.8
Land		264.6	262.7
Construction in progress		3,276.4	3,894.0
Total		42,557.8	40,611.9
Less accumulated depreciation		9,438.4	8,577.2
Property, plant and equipment, net		$ 33,119.4	$ 32,034.7

(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:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
Depreciation expense (1)	$ 309.4	$ 286.2	$ 903.5	$ 870.1
Capitalized interest (2)	38.9	40.3	127.8	105.6

(1) Depreciation expense is a component of "Costs and expenses" as presented on our Unaudited Condensed Statements of Consolidated Operations.
(2) We capitalize interest 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.

Fire at Pascagoula Facility

We acquired the remaining 60% undivided interest in the Pascagoula natural gas processing facility (the "Pascagoula Facility") for $35.0 million in March 2016 and assumed operatorship of the facility on June 1, 2016. The facility is located in Pascagoula, Mississippi and processes natural gas received from third-party production developments located in the northern Gulf of Mexico. On June 27, 2016, we experienced a fire at the facility, which remains out of service as a result of damage sustained during the fire. Repairs to this location have commenced and the facility is expected to return to commercial service during the fourth quarter of 2016.

As a result of this event, we recorded a $7.1 million non-cash loss in the second quarter of 2016 attributable to assets damaged in the fire. In addition, we incurred $7.1 million of expense during the third quarter of 2016 for fire response activities at the Pascagoula Facility. We will capitalize those expenditures we incur to rebuild the facility.

Under our current insurance program, the standalone deductible for property damage claims is $55 million. We also have business interruption protection; however, such claims must involve physical damage and have a combined loss value in excess of $55 million and the period of interruption must exceed 60 days. We continue to evaluate the possibility of filing an insurance claim related to this event.

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 September 30, 2016 and December 31, 2015 includes $21.1 million and $17.6 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset.

The following table presents information regarding our AROs since December 31, 2015:

ARO liability balance, December 31, 2015	$	58.5
Liabilities incurred		4.1
Liabilities settled		(2.9)
Revisions in estimated cash flows		4.0
Accretion expense		2.8
ARO liability balance, September 30, 2016	$	66.5

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.

	Ownership Interest at September 30, 2016	September 30, 2016	December 31, 2015
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C.	13.1%	$ 25.0	$ 25.9
K/D/S Promix, L.L.C.	50%	35.2	38.3
Baton Rouge Fractionators LLC	32.2%	17.1	18.5
Skelly-Belvieu Pipeline Company, L.L.C.	50%	40.0	39.8
Texas Express Pipeline LLC	35%	330.1	342.0
Texas Express Gathering LLC	45%	36.1	36.8
Front Range Pipeline LLC	33.3%	168.0	171.2
Delaware Basin Gas Processing LLC	50%	96.0	46.2
Crude Oil Pipelines & Services:			
Seaway Crude Pipeline Company LLC	50%	1,405.7	1,396.0
Eagle Ford Pipeline LLC	50%	383.6	388.8
Eagle Ford Terminals Corpus Christi LLC	50%	49.4	28.6
Natural Gas Pipelines & Services:			
White River Hub, LLC	50%	22.0	22.5
Petrochemical & Refined Products Services:			
Baton Rouge Propylene Concentrator, LLC	30%	4.6	5.4
Centennial Pipeline LLC	50%	62.7	65.6
Other	Various	11.7	2.9
Total investments in unconsolidated affiliates		$ 2,687.2	$ 2,628.5

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
NGL Pipelines & Services	$ 15.9	$ 18.9	$ 45.0	$ 43.0
Crude Oil Pipelines & Services	78.4	81.2	234.3	220.5
Natural Gas Pipelines & Services	1.0	0.9	2.9	2.8
Petrochemical & Refined Products Services	(3.0)	(3.3)	(12.4)	(10.4)
Offshore Pipelines & Services	--	5.4	--	46.6
Total	$ 92.3	$ 103.1	$ 269.8	$ 302.5

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

	September 30, 2016	December 31, 2015
NGL Pipelines & Services	$ 24.4	$ 25.3
Crude Oil Pipelines & Services	18.7	19.3
Petrochemical & Refined Products Services	2.2	2.3
Total	$ 45.3	$ 46.9

In total, amortization of excess cost amounts was $0.5 million and $0.6 million for the three months ended September 30, 2016 and 2015, respectively. During the nine months ended September 30, 2016 and 2015, amortization of excess cost amounts was $1.6 million and $4.5 million, respectively.

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 September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
Income Statement Data:				
Revenues	$ 328.9	$ 368.2	$ 991.9	$ 1,121.4
Operating income	193.6	225.4	589.0	662.7
Net income	192.0	223.0	585.5	654.1

Note 6. Intangible Assets and Goodwill

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

	September 30, 2016			December 31, 2015		
	Gross Value	Accumulated Amortization	Carrying Value	Gross Value	Accumulated Amortization	Carrying Value
NGL Pipelines & Services:						
Customer relationship intangibles	$ 447.4	$ (168.9)	$ 278.5	$ 447.4	$ (156.9)	$ 290.5
Contract-based intangibles	283.5	(204.3)	79.2	283.0	(193.2)	89.8
Segment total	730.9	(373.2)	357.7	730.4	(350.1)	380.3
Crude Oil Pipelines & Services:						
Customer relationship intangibles	2,204.4	(74.2)	2,130.2	2,204.4	(39.1)	2,165.3
Contract-based intangibles	281.0	(109.3)	171.7	281.4	(69.2)	212.2
Segment total	2,485.4	(183.5)	2,301.9	2,485.8	(108.3)	2,377.5
Natural Gas Pipelines & Services:						
Customer relationship intangibles	1,350.3	(384.1)	966.2	1,350.3	(366.3)	984.0
Contract-based intangibles	464.7	(368.2)	96.5	464.7	(361.0)	103.7
Segment total	1,815.0	(752.3)	1,062.7	1,815.0	(727.3)	1,087.7
Petrochemical & Refined Products Services:						
Customer relationship intangibles	185.5	(42.5)	143.0	185.5	(38.3)	147.2
Contract-based intangibles	56.3	(14.4)	41.9	56.3	(11.8)	44.5
Segment total	241.8	(56.9)	184.9	241.8	(50.1)	191.7
Total intangible assets	$ 5,273.1	$ (1,365.9)	$ 3,907.2	$ 5,273.0	$ (1,235.8)	$ 4,037.2

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
NGL Pipelines & Services	$ 7.6	$ 9.7	$ 23.1	$ 24.9
Crude Oil Pipelines & Services	23.2	29.0	75.6	62.3
Natural Gas Pipelines & Services	8.1	10.7	25.0	30.5
Petrochemical & Refined Products Services	2.3	2.3	6.8	7.0
Offshore Pipelines & Services	--	--	--	4.5
Total	$ 41.2	$ 51.7	$ 130.5	$ 129.2

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

Remainder of 2016	2017	2018	2019	2020
$ 44.6	$ 176.4	$ 171.8	$ 167.3	$ 166.4

Goodwill

Goodwill represents the excess of the purchase price of an acquired business over the amounts assigned to assets acquired and liabilities assumed in the transaction. The following table presents the carrying amount of goodwill at the dates indicated:

	NGL Pipelines & Services	Crude Oil Pipelines & Services	Natural Gas Pipelines & Services	Petrochemical & Refined Products Services	Consolidated Total
Balance at December 31, 2015	$ 2,651.7	$ 1,841.0	$ 296.3	$ 956.2	$ 5,745.2
Balance at September 30, 2016	$ 2,651.7	$ 1,841.0	$ 296.3	$ 956.2	$ 5,745.2

Note 7. Debt Obligations

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

	September 30, 2016	December 31, 2015
EPO senior debt obligations:		
Commercial Paper Notes, variable-rates	$ 2,038.6	$ 1,114.1
Senior Notes AA, 3.20% fixed-rate, due February 2016	--	750.0
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	--
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	--
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	875.0
Senior Notes NN, 4.95% fixed-rate, due October 2054	400.0	400.0
TEPPCO senior debt obligations:		
TEPPCO Senior Notes, 6.65% fixed-rate, due April 2018	0.3	0.3
TEPPCO Senior Notes, 7.55% fixed-rate, due April 2038	0.4	0.4
Total principal amount of senior debt obligations	22,688.6	21,264.1
EPO Junior Subordinated Notes A, fixed/variable-rate, due August 2066 (1)	521.1	521.1
EPO Junior Subordinated Notes C, fixed/variable-rate, due June 2067 (2)	256.4	256.4
EPO Junior Subordinated Notes B, fixed/variable-rate, due January 2068 (3)	682.7	682.7
TEPPCO Junior Subordinated Notes, fixed/variable-rate, due June 2067	14.2	14.2
Total principal amount of senior and junior debt obligations	24,163.0	22,738.5
Other, non-principal amounts	(203.7)	(197.7)
Less current maturities of debt	(2,838.1)	(1,863.9)
Total long-term debt	$ 21,121.2	$ 20,676.9

(1) Fixed rate of 8.375% was paid through August 1, 2016; thereafter, a variable rate is in effect based on 3-month LIBOR plus 3.708%.
(2) Fixed rate of 7.000% through September 1, 2017 (i.e., first call date without a make-whole redemption premium); thereafter, variable rate based on 3-month LIBOR plus 2.778%.
(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 based on 3-month LIBOR plus 2.680%.

At December 31, 2015, we reclassified $149.8 million of bond issuance costs, which were previously accounted for as assets on our consolidated balance sheet, to long-term debt in connection with the adoption of ASU 2015-03 (see Note 1). These amounts are a component of "Other, non-principal amounts" in the preceding table.

The following table presents contractually scheduled maturities of our consolidated debt obligations outstanding at September 30, 2016 for the next five years, and in total thereafter:

		Scheduled Maturities of Debt					
	Total	Remainder of 2016	2017	2018	2019	2020	Thereafter
Commercial Paper Notes	$ 2,038.6	$ 2,038.6	$ --	$ --	$ --	$ --	$ --
Senior Notes	20,650.0	--	800.0	1,100.0	1,500.0	1,500.0	15,750.0
Junior Subordinated Notes	1,474.4	--	--	--	--	--	1,474.4
Total	$ 24,163.0	$ 2,038.6	$ 800.0	$ 1,100.0	$ 1,500.0	$ 1,500.0	$ 17,224.4

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.

Issuance of $1.25 Billion of Senior Notes in April 2016

In April 2016, EPO issued $575 million in principal amount of 2.85% senior notes due April 2021 ("Senior Notes RR"), $575 million in principal amount of 3.95% senior notes due February 2027 ("Senior Notes SS") and $100 million in principal amount of 4.90% reopened senior notes due May 2046 ("Senior Notes QQ"). Senior Notes RR, SS and QQ were issued at 99.898%, 99.760% and 95.516% of their principal amounts, respectively. We issued these senior notes using our 2013 Shelf (see Note 8).

Net proceeds from the issuance of these senior notes were used as follows: (i) the repayment of amounts then outstanding under EPO's commercial paper program, which included amounts we used to repay $750 million in principal amount of Senior Notes AA that matured in February 2016, and (ii) for general company purposes.

Enterprise Products Partners L.P. has unconditionally guaranteed these senior notes on an unsecured and unsubordinated basis. These senior notes rank equal with EPO's existing and future unsecured and unsubordinated indebtedness and are senior to any existing and future subordinated indebtedness of EPO. These senior notes are subject to make-whole redemption rights and were issued under an indenture containing certain covenants, which generally restrict EPO's ability (with certain exceptions) to incur debt secured by liens and engage in sale and leaseback transactions.

364-Day Credit Agreement

In September 2016, EPO amended its 364-Day Credit Agreement to extend its maturity date to September 2017. There are currently no principal amounts outstanding under this revolving credit agreement. Under the terms of the 364-Day 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, subject to the terms and conditions set forth therein. To the extent that principal amounts are outstanding at the maturity date, EPO may elect to have the entire principal balance then outstanding continued as a non-revolving term loan for a period of one additional year, payable in September 2018. The remaining terms of the 364-Day Credit Agreement, as amended, remain materially the same as those reported for the 364-Day Credit Agreement in our 2015 Form 10-K.

Letters of Credit

At September 30, 2016, EPO had $67.7 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 September 30, 2016.

Information Regarding Variable Interest Rates Paid

The following table presents the range of interest rates and weighted-average interest rates paid on our consolidated variable-rate debt during the nine months ended September 30, 2016:

	Range of Interest Rates Paid	Weighted-Average Interest Rate Paid
Commercial Paper Notes	0.56% to 1.18%	0.89%
Junior Subordinated Notes A	4.46%	4.46%
Multi-Year Revolving Credit Facility	1.43% to 1.43%	1.43%

Note 8. Equity and Distributions

Partners Equity

Partners' equity reflects the limited partner interests (i.e., common units, including restricted common units) that we have outstanding. The following table summarizes changes in the number of our outstanding units from December 31, 2015 to September 30, 2016:

	Common Units (Unrestricted)	Restricted Common Units	Total Common Units
Number of units outstanding at December 31, 2015	2,010,592,504	1,960,520	2,012,553,024
Common units issued in connection with ATM program	76,113,492	--	76,113,492
Common units issued in connection with DRIP and EUPP	13,334,558	--	13,334,558
Common units issued in connection with the vesting of phantom unit awards	1,149,450	--	1,149,450
Common units issued in connection with the vesting of restricted common unit awards	1,214,178	(1,214,178)	--
Forfeiture of restricted common unit awards	--	(41,774)	(41,774)
Acquisition and cancellation of treasury units in connection with the vesting of equity-based awards	(403,229)	--	(403,229)
Other	90,707	--	90,707
Number of units outstanding at September 30, 2016	2,102,091,660	704,568	2,102,796,228

The net cash proceeds we received from the issuance of common units during the nine months ended September 30, 2016 were used to temporarily reduce principal 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

On May 12, 2016, we filed with the SEC a new universal shelf registration statement (the "2016 Shelf"), which was immediately effective and replaced our prior universal shelf registration statement filed with the SEC in June 2013 (the "2013 Shelf"). The 2016 Shelf allows (and the prior 2013 Shelf allowed) Enterprise Products Partners L.P. and EPO (each on a standalone basis) to issue an unlimited amount of equity and debt securities, respectively. See Note 7 for information regarding an offering of senior notes we completed in April 2016 using the 2013 Shelf.

At-the-Market ("ATM") program

On July 11, 2016, we filed an amended registration statement 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. Pursuant to the ATM program, we may sell common units under an equity distribution agreement between Enterprise Products Partners L.P. and certain broker-dealers from time-to-time by means of ordinary brokers' transactions through the NYSE at market prices, in block transactions or as otherwise agreed to with the broker-dealer parties to the agreement. The new registration statement was declared effective on July 14, 2016 and replaced our prior registration statement with respect to the ATM program.

During the nine months ended September 30, 2016, we sold 76,113,492 common units under the ATM program for aggregate gross proceeds of $1.87 billion. This includes 3,830,256 common units sold in January 2016 to privately held affiliates of EPCO, which generated gross proceeds of $100 million. After taking into account applicable costs, our transactions under the ATM program resulted in aggregate net cash proceeds of $1.85 billion during the nine months ended September 30, 2016. During the nine months ended September 30, 2015, we issued 23,258,453 common units under this program for aggregate gross cash proceeds of $767.1 million, resulting in total net cash proceeds of $759.7 million. This includes 3,225,057 common units sold in March 2015 to a privately held affiliate of EPCO, which generated gross proceeds of $100 million. Following the effectiveness of the new ATM registration statement and after taking into account the aggregate sales price of common units sold under the ATM program through September 30, 2016, we have the capacity to issue additional common units under the ATM program up to an aggregate sales price of $1.75 billion.

Distribution reinvestment plan
On May 12, 2016, we filed with the SEC a new registration statement in connection with our distribution reinvestment plan ("DRIP"), which was immediately effective and amended a prior registration statement filed in March 2010. The new registration statement increased the aggregate number of our common units authorized for issuance under the DRIP from 140,000,000 to 240,000,000. 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 12,946,724 common units under our DRIP during the nine months ended September 30, 2016, which generated net cash proceeds of $306.2 million. During the nine months ended September 30, 2015, we issued 7,965,318 common units under our DRIP, which generated net cash proceeds of $242.8 million. Privately held affiliates of EPCO reinvested $100 million through the DRIP during the nine months ended September 30, 2016 (this amount being a component of the net cash proceeds presented).

After taking into account the new registration statement and the number of common units issued under the DRIP through September 30, 2016, we have the capacity to issue an additional 102,121,274 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 387,834 common units under our EUPP during the nine months ended September 30, 2016, which generated net cash proceeds of $9.8 million. During the nine months ended September 30, 2015, we issued 285,997 common units under our EUPP, which generated net cash proceeds of $8.9 million. After taking into account the number of common units issued under the EUPP through September 30, 2016, we may issue an additional 6,384,672 common units under this plan.

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).

Accumulated Other Comprehensive Loss

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

	Gains (Losses) on Cash Flow Hedges: Commodity Derivative Instruments	Gains (Losses) on Cash Flow Hedges: Interest Rate Derivative Instruments	Other	Total
Balance, December 31, 2015	$ 56.6	$ (279.5)	$ 3.7	$ (219.2)
Other comprehensive loss before reclassifications	(52.2)	(16.3)	(0.1)	(68.6)
Amounts reclassified from accumulated other comprehensive loss (income)	(48.7)	27.8	--	(20.9)
Total other comprehensive income (loss)	(100.9)	11.5	(0.1)	(89.5)
Balance, September 30, 2016	$ (44.3)	$ (268.0)	$ 3.6	$ (308.7)

	Gains (Losses) on Cash Flow Hedges: Commodity Derivative Instruments	Gains (Losses) on Cash Flow Hedges: Interest Rate Derivative Instruments	Other	Total
Balance, December 31, 2014	$ 69.9	$ (314.8)	$ 3.3	$ (241.6)
Other comprehensive income before reclassifications	112.3	--	0.4	112.7
Amounts reclassified from accumulated other comprehensive loss (income)	(128.1)	26.3	--	(101.8)
Total other comprehensive income (loss)	(15.8)	26.3	0.4	10.9
Balance, September 30, 2015	$ 54.1	$ (288.5)	$ 3.7	$ (230.7)

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

	Location	For the Three Months Ended September 30, 2016	For the Three Months Ended September 30, 2015	For the Nine Months Ended September 30, 2016	For the Nine Months Ended September 30, 2015
Losses (gains) on cash flow hedges:					
Interest rate derivatives	Interest expense	$ 9.4	$ 8.9	$ 27.8	$ 26.3
Commodity derivatives	Revenue	(23.0)	(46.8)	(47.6)	(128.6)
Commodity derivatives	Operating costs and expenses	(3.9)	--	(1.1)	0.5
Total		$ (17.5)	$ (37.9)	$ (20.9)	$ (101.8)

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:

	Distribution Per Common Unit	Record Date	Payment Date
2015:			
1st Quarter	$ 0.3750	4/30/2015	5/7/2015
2nd Quarter	$ 0.3800	7/31/2015	8/7/2015
3rd Quarter	$ 0.3850	10/30/2015	11/6/2015
2016:			
1st Quarter	$ 0.3950	4/29/2016	5/6/2016
2nd Quarter	$ 0.4000	7/29/2016	8/5/2016
3rd Quarter	$ 0.4050	10/31/2016	11/7/2016

In November 2010, we completed our merger with Enterprise GP Holdings L.P. (the "Holdings Merger"). In connection with the Holdings Merger, a privately held affiliate of EPCO agreed to temporarily waive the regular cash distributions it would otherwise receive from us with respect to a certain number of our common units it owns (the "Designated Units"). Distributions paid to partners during 2015 reflected the exclusion of 35,380,000 Designated Units. The temporary distribution waiver expired in November 2015; therefore, distributions paid to partners during calendar year 2016 are payable on all outstanding common units.

Note 9. Business Segments

Our historical operations are reported under five business segments: (i) NGL Pipelines & Services, (ii) Crude Oil Pipelines & Services, (iii) Natural Gas Pipelines & Services, (iv) Petrochemical & Refined Products Services and (v) Offshore Pipelines & Services. On July 24, 2015, we completed the sale of our Offshore Business, which primarily consisted of our Offshore Pipelines & Services segment. Our consolidated financial statements reflect ownership of the Offshore Business through July 24, 2015.

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

We evaluate segment performance based on 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 GAAP financial measure most directly comparable to total segment gross operating margin is operating income.

Gross operating margin represents GAAP operating income exclusive of (i) depreciation, amortization and accretion expenses, (ii) impairment charges, (iii) gains and losses attributable to asset sales, insurance recoveries and related property damage and (iv) general and administrative costs. Gross operating margin includes (i) equity in the earnings of unconsolidated affiliates and (ii) non-refundable deferred transportation revenues relating to the make-up rights of committed shippers on certain pipeline assets. 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. 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 above, as applicable, and before the elimination of intercompany transactions.

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

Substantially all of our plants, pipelines and other fixed assets are located in the U.S.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
Revenues	$ 5,920.4	$ 6,307.9	$ 16,543.5	$ 20,872.9
Subtract operating costs and expenses	(5,065.7)	(5,452.6)	(14,034.8)	(18,426.5)
Add equity in income of unconsolidated affiliates	92.3	103.1	269.8	302.5
Add depreciation, amortization and accretion expense amounts not reflected in gross operating margin	367.1	351.1	1,085.6	1,082.0
Add asset impairment charges not reflected in gross operating margin	6.8	26.8	21.6	139.1
Add net losses or subtract net gains attributable to asset sales, insurance recoveries and related property damage not reflected in gross operating margin	(8.9)	12.3	4.8	14.7
Add non-refundable payments attributable to shipper make-up rights on new pipeline projects reflected in gross operating margin	1.2	3.4	10.1	39.3
Subtract subsequent revenue recognition of deferred revenues attributable to make-up rights not reflected in gross operating margin	(5.6)	(10.9)	(25.1)	(45.3)
Total segment gross operating margin	$ 1,307.6	$ 1,341.1	$ 3,875.5	$ 3,978.7

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
Total segment gross operating margin	$ 1,307.6	$ 1,341.1	$ 3,875.5	$ 3,978.7
Adjustments to reconcile total segment gross operating margin to operating income:				
Subtract depreciation, amortization and accretion expense amounts not reflected in gross operating margin	(367.1)	(351.1)	(1,085.6)	(1,082.0)
Subtract asset impairment charges not reflected in gross operating margin	(6.8)	(26.8)	(21.6)	(139.1)
Add net gains or subtract net losses attributable to asset sales, insurance recoveries and related property damage not reflected in gross operating margin	8.9	(12.3)	(4.8)	(14.7)
Subtract non-refundable payments attributable to shipper make-up rights on new pipeline projects reflected in gross operating margin	(1.2)	(3.4)	(10.1)	(39.3)
Add subsequent revenue recognition of deferred revenues attributable to make-up rights not reflected in gross operating margin	5.6	10.9	25.1	45.3
Subtract general and administrative costs not reflected in gross operating margin	(42.0)	(49.0)	(121.0)	(143.2)
Operating income	905.0	909.4	2,657.5	2,605.7
Other expense, net	(257.1)	(246.2)	(761.1)	(736.4)
Income before income taxes	$ 647.9	$ 663.2	$ 1,896.4	$ 1,869.3

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

	Business Segments						
	NGL Pipelines & Services	Crude Oil Pipelines & Services	Natural Gas Pipelines & Services	Petrochemical & Refined Products Services	Offshore Pipelines & Services	Adjustments and Eliminations	Consolidated Total
Revenues from third parties:							
Three months ended September 30, 2016	$ 2,414.2	$ 1,712.9	$ 711.3	$ 1,066.3	$ --	$ --	$ 5,904.7
Three months ended September 30, 2015	2,284.6	2,316.4	705.2	980.0	7.8	--	6,294.0
Nine months ended September 30, 2016	7,328.9	4,641.8	1,792.5	2,735.8	--	--	16,499.0
Nine months ended September 30, 2015	7,223.2	8,080.4	2,117.5	3,347.6	76.9	--	20,845.6
Revenues from related parties:							
Three months ended September 30, 2016	2.7	10.1	2.9	--	--	--	15.7
Three months ended September 30, 2015	2.2	6.2	4.5	--	1.0	--	13.9
Nine months ended September 30, 2016	7.3	29.8	7.4	--	--	--	44.5
Nine months ended September 30, 2015	6.0	8.6	10.8	--	1.9	--	27.3
Intersegment and intrasegment revenues:							
Three months ended September 30, 2016	4,772.4	2,445.2	201.2	315.4	--	(7,734.2)	--
Three months ended September 30, 2015	2,461.0	1,142.1	180.2	267.3	0.1	(4,050.7)	--
Nine months ended September 30, 2016	12,828.0	6,390.3	472.8	865.8	--	(20,556.9)	--
Nine months ended September 30, 2015	7,685.1	3,958.9	519.7	875.8	0.6	(13,040.1)	--
Total revenues:							
Three months ended September 30, 2016	7,189.3	4,168.2	915.4	1,381.7	--	(7,734.2)	5,920.4
Three months ended September 30, 2015	4,747.8	3,464.7	889.9	1,247.3	8.9	(4,050.7)	6,307.9
Nine months ended September 30, 2016	20,164.2	11,061.9	2,272.7	3,601.6	--	(20,556.9)	16,543.5
Nine months ended September 30, 2015	14,914.3	12,047.9	2,648.0	4,223.4	79.4	(13,040.1)	20,872.9
Equity in income (loss) of unconsolidated affiliates:							
Three months ended September 30, 2016	15.9	78.4	1.0	(3.0)	--	--	92.3
Three months ended September 30, 2015	18.9	81.2	0.9	(3.3)	5.4	--	103.1
Nine months ended September 30, 2016	45.0	234.3	2.9	(12.4)	--	--	269.8
Nine months ended September 30, 2015	43.0	220.5	2.8	(10.4)	46.6	--	302.5
Gross operating margin:							
Three months ended September 30, 2016	703.5	254.0	178.5	171.6	--	--	1,307.6
Three months ended September 30, 2015	695.5	254.6	192.4	191.5	7.1	--	1,341.1
Nine months ended September 30, 2016	2,206.3	633.7	533.6	501.9	--	--	3,875.5
Nine months ended September 30, 2015	2,041.3	704.2	588.3	547.4	97.5	--	3,978.7
Property, plant and equipment, net: (see Note 4)							
At September 30, 2016	14,040.1	4,074.1	8,473.7	3,255.1	--	3,276.4	33,119.4
At December 31, 2015	12,909.7	3,550.3	8,620.0	3,060.7	--	3,894.0	32,034.7
Investments in unconsolidated affiliates: (see Note 5)							
At September 30, 2016	747.5	1,838.7	22.0	79.0	--	--	2,687.2
At December 31, 2015	718.7	1,813.4	22.5	73.9	--	--	2,628.5
Intangible assets, net: (see Note 6)							
At September 30, 2016	357.7	2,301.9	1,062.7	184.9	--	--	3,907.2
At December 31, 2015	380.3	2,377.5	1,087.7	191.7	--	--	4,037.2
Goodwill: (see Note 6)							
At September 30, 2016	2,651.7	1,841.0	296.3	956.2	--	--	5,745.2
At December 31, 2015	2,651.7	1,841.0	296.3	956.2	--	--	5,745.2
Segment assets:							
At September 30, 2016	17,797.0	10,055.7	9,854.7	4,475.2	--	3,276.4	45,459.0
At December 31, 2015	16,660.4	9,582.2	10,026.5	4,282.5	--	3,894.0	44,445.6

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

	For the Three Months Ended September 30, 2016	For the Three Months Ended September 30, 2015	For the Nine Months Ended September 30, 2016	For the Nine Months Ended September 30, 2015
NGL Pipelines & Services:				
Sales of NGLs and related products	$ 1,959.0	$ 1,844.9	$ 5,962.9	$ 5,936.2
Midstream services	457.9	441.9	1,373.3	1,293.0
Total	2,416.9	2,286.8	7,336.2	7,229.2
Crude Oil Pipelines & Services:				
Sales of crude oil	1,538.5	2,147.3	4,141.8	7,689.3
Midstream services	184.5	175.3	529.8	399.7
Total	1,723.0	2,322.6	4,671.6	8,089.0
Natural Gas Pipelines & Services:				
Sales of natural gas	483.7	455.0	1,104.4	1,361.2
Midstream services	230.5	254.7	695.5	767.1
Total	714.2	709.7	1,799.9	2,128.3
Petrochemical & Refined Products Services:				
Sales of petrochemicals and refined products	871.3	780.5	2,137.9	2,764.2
Midstream services	195.0	199.5	597.9	583.4
Total	1,066.3	980.0	2,735.8	3,347.6
Offshore Pipelines & Services:				
Sales of crude oil	--	0.4	--	3.2
Midstream services	--	8.4	--	75.6
Total	--	8.8	--	78.8
Total consolidated revenues	$ 5,920.4	$ 6,307.9	$ 16,543.5	$ 20,872.9
Consolidated costs and expenses				
Operating costs and expenses:				
Cost of sales	$ 4,088.6	$ 4,419.9	$ 11,135.6	$ 15,355.9
Other operating costs and expenses (1)	612.1	642.5	1,787.2	1,834.8
Depreciation, amortization and accretion	367.1	351.1	1,085.6	1,082.0
Asset impairment charges	6.8	26.8	21.6	139.1
Loss due to Pascagoula fire	--	--	7.1	--
Net losses (gains) attributable to asset sales	(8.9)	12.3	(2.3)	14.7
General and administrative costs	42.0	49.0	121.0	143.2
Total consolidated costs and expenses	$ 5,107.7	$ 5,501.6	$ 14,155.8	$ 18,569.7

(1) Represents the cost of operating our plants, pipelines and other fixed assets excluding: depreciation, amortization and accretion charges; asset impairment charges; losses due to property damage events (e.g., the fire at our Pascagoula Facility (see Note 4)); 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, lower energy commodity prices result in a decrease in our revenues attributable to product sales; however, these lower commodity prices also decrease the associated cost of sales as purchase costs decline. The same correlation would be true in the case of higher energy commodity sales prices and purchase costs.

Note 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 September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
BASIC EARNINGS PER UNIT				
Net income attributable to limited partners	$ 634.6	$ 649.3	$ 1,854.3	$ 1,836.4
Undistributed earnings allocated and cash payments on phantom unit awards (1)	(3.2)	(2.2)	(9.7)	(6.6)
Net income available to common unitholders	$ 631.4	$ 647.1	$ 1,844.6	$ 1,829.8
Basic weighted-average number of common units outstanding	2,097.5	1,969.3	2,072.2	1,952.3
Basic earnings per unit	$ 0.30	$ 0.33	$ 0.89	$ 0.94
DILUTED EARNINGS PER UNIT				
Net income attributable to limited partners	$ 634.6	$ 649.3	$ 1,854.3	$ 1,836.4
Diluted weighted-average number of units outstanding:				
Distribution-bearing common units	2,097.5	1,969.3	2,072.2	1,952.3
Designated Units	--	35.4	--	35.4
Phantom units (1)	8.0	5.7	7.6	5.4
Incremental option units	--	0.1	--	0.2
Total	2,105.5	2,010.5	2,079.8	1,993.3
Diluted earnings per unit	$ 0.30	$ 0.32	$ 0.89	$ 0.92

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

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 September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
Equity-classified awards:				
Phantom unit awards	$ 19.9	$ 20.3	$ 58.6	$ 60.2
Restricted common unit awards	0.8	3.1	3.7	13.1
Profits interest awards	1.5	--	3.8	--
Liability-classified awards	0.1	--	0.4	0.2
Total	$ 22.3	$ 23.4	$ 66.5	$ 73.5

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

At September 30, 2016, EPCO's significant long-term incentive plans applicable to us were the Enterprise Products 1998 Long-Term Incentive Plan ("1998 Plan") and the 2008 Enterprise Products Long-Term Incentive Plan (Third Amendment and Restatement) ("2008 Plan"). Up to 14,000,000 of our common units may be issued as awards under the 1998 Plan. The maximum number of common units authorized for issuance under the 2008 Plan was 35,000,000 at September 30, 2016. This authorized amount will automatically increase under the terms of the 2008 Plan by 5,000,000 common units on January 1, 2017 and will continue to automatically increase annually on January 1 thereafter during the term of the 2008 Plan; provided, however, that in no event shall the maximum aggregate number exceed 70,000,000 common units. After giving effect to awards granted under the 1998 Plan and 2008 Plan through September 30, 2016, a total of 3,255,545 and 18,297,995 additional common units were available for issuance under these plans, respectively.

In addition, during the first half of 2016, EPCO formed four limited partnerships (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"). The Employee Partnerships are discussed later in this note.

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 September 30, 2016, substantially all of our phantom unit awards are expected to result in the issuance of common units upon vesting; therefore, the applicable awards are accounted for as equity-classified awards. The grant date fair value of a phantom unit award is based on the market price per unit of our common units on the date of grant. Compensation expense is recognized based on the grant date fair value, net of an allowance for estimated forfeitures, over the requisite service or vesting period.

The following table presents phantom unit award activity for the period indicated:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Phantom unit awards at December 31, 2015	5,426,949	$ 33.63
Granted (2)	4,486,910	$ 21.88
Vested	(1,728,388)	$ 33.13
Forfeited	(364,506)	$ 28.71
Phantom unit awards at September 30, 2016	7,820,965	$ 27.23

(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 2016 was $98.2 million based on grant date market prices of our common units ranging from $21.86 per unit to $27.39 per unit. An estimated annual forfeiture rate of 3.9% was applied to these awards.

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

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
Cash payments made in connection with DERs	$ 3.2	$ 2.2	$ 8.5	$ 5.6
Total intrinsic value of phantom unit awards that vested during period	3.0	2.3	40.1	31.0

For the EPCO group of companies, the unrecognized compensation cost associated with phantom unit awards was $99.7 million at September 30, 2016, of which our share of the cost is currently estimated to be $89.9 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 2.0 years.

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)
Restricted common units at December 31, 2015	1,960,520	$ 27.88
Vested	(1,214,178)	$ 27.45
Forfeited	(41,774)	$ 28.46
Restricted common units at September 30, 2016	704,568	$ 28.58

(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 September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
Cash distributions paid to restricted common unitholders	$ 0.3	$ 0.8	$ 1.4	$ 3.2
Total intrinsic value of restricted common unit awards that vested during period	0.7	1.5	28.0	66.9

For the EPCO group of companies, the unrecognized compensation cost associated with restricted common unit awards was an aggregate $1.9 million at September 30, 2016, of which our share of the cost is currently estimated to be $1.4 million. We expect to recognize our share of the unrecognized compensation cost for these awards by the end of 2017.

Unit Option Awards

EPCO's long-term incentive plans provide for the issuance of non-qualified incentive options denominated in our common units. All of our unit option awards had been exercised as of December 31, 2015 and no new unit option awards were granted during the nine months ended September 30, 2016.

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

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

	For the Three Months Ended September 30, 2015	For the Nine Months Ended September 30, 2015
Total intrinsic value of unit option awards exercised during period	$ 0.2	$ 19.8
Cash received from EPCO in connection with the exercise of unit option awards	0.2	11.5
Unit option award-related cash reimbursements to EPCO	0.2	19.8

Profits Interest Awards

On February 22, 2016, EPCO Holdings Inc. ("EPCO Holdings"), a privately held affiliate of EPCO, contributed the following Enterprise common units it owned to the Employee Partnerships: (i) 2,723,052 units to PubCo I, (ii) 2,834,198 units to PubCo II and (iii) 1,111,438 units to PrivCo I. On April 6, 2016, EPCO Holdings contributed 105,000 Enterprise common units it owned to PubCo III. 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.

In general, the Class A limited partner earns a preferred return (the "Class A Preference Return," as described below) on its investment (or "Capital Base") in each Employee Partnership, with any residual cash amounts being paid to the Class B limited partners of such Employee Partnership on a quarterly basis. Upon liquidation of an Employee Partnership, assets having a then current fair market value equal to the Class A limited partner's Capital Base in such Employee Partnership, plus any preferred return for the period in which liquidation occurs, will be distributed to the Class A limited partner. Any remaining assets of such Employee Partnership will be distributed to the Class B limited partners of such Employee Partnership as a residual profits interest, which represents the appreciation in value of the Employee Partnership's assets since the date of EPCO Holdings' contribution to it, as described above.

Unless otherwise agreed to by EPCO and a majority in interest of the limited partners of each Employee Partnership, such Employee Partnership will terminate at the earliest to occur of (i) 30 days following its vesting date, (ii) a change of control or (iii) a dissolution of the Employee Partnership. The Class B limited partner interests in each Employee Partnership vest as follows: PubCo I, four years from February 22, 2016; PubCo II and PrivCo I, five years from February 22, 2016; and PubCo III, four years from April 6, 2016.

Individually, each Class B limited partner interest is subject to forfeiture if the participating employee's employment with EPCO is terminated prior to vesting, with customary exceptions for death, disability and certain retirements. The risk of forfeiture will also lapse upon certain change of control events. Forfeited individual Class B limited partner interests are allocated to the remaining Class B limited partners.

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 Partner Preferred Return Rate (2)	Expected Liquidation Date	Estimated Grant Date Fair Value of Profits Interest Awards (3)	Unrecognized Compensation Cost (4)
PubCo I	2,723,052 units	$63.5 million	6.6638%	Feb. 2020	$13.2 million	$11.2 million
PubCo II	2,834,198 units	$66.1 million	6.6638%	Feb. 2021	$14.8 million	$12.9 million
PubCo III	105,000 units	$2.5 million	6.5381%	Apr. 2020	$0.5 million	$0.5 million
PrivCo I	1,111,438 units	$25.9 million	6.6638%	Feb. 2021	$5.8 million	$1.1 million

(1) Represents fair market value of the Enterprise common units contributed to each Employee Partnership at the applicable contribution date.

(2) For each period and Employee Partnership, the Class A Preference Return amount equals the Class A Capital Base, after adjusting for certain retained cash distributions and other amounts as defined in the underlying agreements, multiplied by the applicable Class A Partner Preferred Return Rate divided by 365 or 366 days, as the case may be during such calendar year, multiplied by the number of days in the applicable period.

(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 September 30, 2016. 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 3.4 years, 4.4 years, 3.5 years and 4.4 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.

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 6.7%	29% to 40%
PubCo II	5.0 years	1.1% to 1.3%	6.2% to 6.7%	27% to 40%
PubCo III	4.0 years	0.9% to 1.0%	6.2%	29% to 40%
PrivCo I	5.0 years	1.1% to 1.3%	6.2% to 6.7%	27% 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.

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 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 September 30, 2016:

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 1.27%	Fair value hedge

As a result of lower market interest rates in June and July 2016, we entered into eight 30-year forward-starting swaps associated with anticipated future issuances of debt. At September 30, 2016, our portfolio of forward starting swaps was as follows:

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	$250.0	9/2017	1.91%	Cash flow hedge
Future long-term debt offering	4 forward starting swaps	$275.0	5/2018	2.02%	Cash flow hedge

As a result of market conditions in October 2016, we elected to terminate the forward starting swaps that were scheduled to settle in September 2017, which resulted in cash gains totaling $6.1 million. As cash flow hedges, gains on these derivative instruments will be reflected as a component of accumulated other comprehensive income and be amortized to earnings (as a decrease in interest expense) over the life of the associated future debt obligations beginning in September 2017.

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. The following table summarizes our portfolio of commodity derivative instruments outstanding at September 30, 2016 (volume measures as noted):

	Volume (1)		Accounting
Derivative Purpose	**Current** (2)	**Long-Term** (2)	**Treatment**
Derivatives designated as hedging instruments:			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction (Bcf)	24.4	3.3	Cash flow hedge
Forecasted sales of NGLs (MMBbls)	12.1	3.5	Cash flow hedge
Octane enhancement:			
Forecasted purchase of NGLs (MMBbls)	1.3	n/a	Cash flow hedge
Forecasted sales of octane enhancement products (MMBbls)	1.4	n/a	Cash flow hedge
Natural gas marketing:			
Forecasted purchases of natural gas for fuel (Bcf)	3.3	0.5	Cash flow hedge
Natural gas storage inventory management activities (Bcf)	8.2	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	78.2	2.3	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	99.0	7.0	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products (MMBbls)	0.3	n/a	Cash flow hedge
Forecasted sales of refined products (MMBbls)	0.4	n/a	Cash flow hedge
Refined products inventory management activities (MMBbls)	2.1	n/a	Fair value hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	7.4	n/a	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	11.5	n/a	Cash flow hedge
Crude oil inventory management activities (MMBbls)	0.2	n/a	Fair value hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (Bcf) (3,4)	98.2	20.9	Mark-to-market
NGL risk management activities (MMBbls) (4)	7.2	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (4)	28.5	0.9	Mark-to-market

(1) Volume for derivatives designated as hedging instruments reflects the total amount of volumes hedged whereas volume for derivatives not designated as hedging instruments reflects the absolute value of derivative notional volumes.

(2) The maximum term for derivatives designated as cash flow hedges, derivatives designated as fair value hedges and derivatives not designated as hedging instruments is December 2017, June 2017 and March 2020, respectively.

(3) Current and long-term volumes include 25.4 Bcf and 1.8 Bcf, respectively, of physical derivative instruments that are predominantly priced at a marked-based index plus a premium or minus a discount related to location differences.

(4) Reflects the use of derivative instruments to manage risks associated with transportation, processing and storage assets.

At September 30, 2016, 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 sales contracts 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.

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			
	September 30, 2016		December 31, 2015		September 30, 2016		December 31, 2015	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments								
Interest rate derivatives	Current assets	$ 3.0	Current assets	$ 3.2	Current liabilities	$ --	Current liabilities	$ --
Interest rate derivatives	Other assets	0.5	Other assets	--	Other liabilities	16.3	Other liabilities	3.7
Total interest rate derivatives		3.5		3.2		16.3		3.7
Commodity derivatives	Current assets	202.6	Current assets	253.8	Current liabilities	407.1	Current liabilities	137.5
Commodity derivatives	Other assets	5.7	Other assets	0.2	Other liabilities	6.0	Other liabilities	1.4
Total commodity derivatives		208.3		254.0		413.1		138.9
Total derivatives designated as hedging instruments		$ 211.8		$ 257.2		$ 429.4		$ 142.6
Derivatives not designated as hedging instruments								
Commodity derivatives	Current assets	$ 35.8	Current assets	$ 1.6	Current liabilities	$ 57.1	Current liabilities	$ 3.1
Commodity derivatives	Other assets	1.6	Other assets	--	Other liabilities	5.2	Other liabilities	1.0
Total commodity derivatives		$ 37.4		$ 1.6		$ 62.3		$ 4.1

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

Offsetting of Financial Assets and Derivative Assets

	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Amounts of Assets Presented in the Balance Sheet	Gross Amounts Not Offset in the Balance Sheet: Financial Instruments	Gross Amounts Not Offset in the Balance Sheet: Cash Collateral Received	Gross Amounts Not Offset in the Balance Sheet: Cash Collateral Paid	Amounts That Would Have Been Presented On Net Basis
	(i)	(ii)	(iii) = (i) – (ii)	(iv)			(v) = (iii) + (iv)
As of September 30, 2016:							
Interest rate derivatives	$ 3.5	$ --	$ 3.5	$ (2.1)	$ --	$ --	$ 1.4
Commodity derivatives	245.7	--	245.7	(244.1)	--	8.9	10.5
As of December 31, 2015:							
Interest rate derivatives	$ 3.2	$ --	$ 3.2	$ (3.2)	$ --	$ --	$ --
Commodity derivatives	255.6	--	255.6	(143.0)	(72.2)	(40.1)	0.3

Offsetting of Financial Liabilities and Derivative Liabilities

	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Balance Sheet	Amounts of Liabilities Presented in the Balance Sheet	Gross Amounts Not Offset in the Balance Sheet: Financial Instruments	Gross Amounts Not Offset in the Balance Sheet: Cash Collateral Paid	Amounts That Would Have Been Presented On Net Basis
	(i)	(ii)	(iii) = (i) – (ii)	(iv)		(v) = (iii) + (iv)
As of September 30, 2016:						
Interest rate derivatives	$ 16.3	$ --	$ 16.3	$ (2.1)	$ --	$ 14.2
Commodity derivatives	475.4	--	475.4	(244.1)	(231.3)	--
As of December 31, 2015:						
Interest rate derivatives	$ 3.7	$ --	$ 3.7	$ (3.2)	$ --	$ 0.5
Commodity derivatives	143.0	--	143.0	(143.0)	--	--

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 September 30, 2016	2015	For the Nine Months Ended September 30, 2016	2015
Interest rate derivatives	Interest expense	$ (3.8)	$ 5.9	$ 3.5	$ 5.1
Commodity derivatives	Revenue	(0.4)	3.6	(82.4)	4.0
Total		$ (4.2)	$ 9.5	$ (78.9)	$ 9.1

Derivatives in Fair Value Hedging Relationships	Location	Gain (Loss) Recognized in Income on Hedged Item: For the Three Months Ended September 30, 2016	2015	For the Nine Months Ended September 30, 2016	2015
Interest rate derivatives	Interest expense	$ 3.8	$ (5.7)	$ (3.7)	$ (5.2)
Commodity derivatives	Revenue	2.1	(2.5)	110.9	7.4
Total		$ 5.9	$ (8.2)	$ 107.2	$ 2.2

For the nine months ended September 30, 2016, the net gain of $28.5 million recognized in income from our commodity derivatives designated as fair value hedges includes $0.8 million of net gains attributable to hedge ineffectiveness. The remaining $27.7 million of net gain recognized during the nine months ended September 30, 2016 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 September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
Interest rate derivatives	$ (6.9)	$ --	$ (16.3)	$ --
Commodity derivatives – Revenue (1)	23.8	87.4	(53.4)	113.9
Commodity derivatives – Operating costs and expenses (1)	(1.1)	(1.6)	1.2	(1.6)
Total	$ 15.8	$ 85.8	$ (68.5)	$ 112.3

(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.

Derivatives in Cash Flow Hedging Relationships	Location	Gain (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) to Income (Effective Portion)			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2016	2015	2016	2015
Interest rate derivatives	Interest expense	$ (9.4)	$ (8.9)	$ (27.8)	$ (26.3)
Commodity derivatives	Revenue	23.0	46.8	47.6	128.6
Commodity derivatives	Operating costs and expenses	3.9	--	1.1	(0.5)
Total		$ 17.5	$ 37.9	$ 20.9	$ 101.8

Derivatives in Cash Flow Hedging Relationships	Location	Gain (Loss) Recognized in Income on Derivative (Ineffective Portion)			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2016	2015	2016	2015
Commodity derivatives	Revenue	$ --	$ (3.5)	$ --	$ (3.1)
Commodity derivatives	Operating costs and expenses	(0.3)	--	(0.3)	--
Total		$ (0.3)	$ (3.5)	$ (0.3)	$ (3.1)

Over the next twelve months, we expect to reclassify $39.5 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 $43.6 million of net losses attributable to commodity derivative instruments from accumulated other comprehensive income to earnings, $44.0 million as a decrease in revenue and $0.4 million as a decrease in operating costs and expenses.

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

Derivatives Not Designated as Hedging Instruments	Location	Gain (Loss) Recognized in Income on Derivative			
		For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
		2016	2015	2016	2015
Commodity derivatives	Revenue	$ 18.3	$ --	$ (28.3)	$ 3.9
Commodity derivatives	Operating costs and expenses	--	(0.3)	--	--
Total		$ 18.3	$ (0.3)	$ (28.3)	$ 3.9

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.

	September 30, 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
Financial assets:				
Interest rate derivatives	$ --	$ 3.5	$ --	$ 3.5
Commodity derivatives	82.2	149.1	14.4	245.7
Total	$ 82.2	$ 152.6	$ 14.4	$ 249.2
Financial liabilities:				
Liquidity Option Agreement	$ --	$ --	$ 273.1	$ 273.1
Interest rate derivatives	--	16.3	--	16.3
Commodity derivatives	202.8	256.6	16.0	475.4
Total	$ 202.8	$ 272.9	$ 289.1	$ 764.8

	December 31, 2015 Fair Value Measurements Using			
	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Financial assets:				
Interest rate derivatives	$ --	$ 3.2	$ --	$ 3.2
Commodity derivatives	109.5	145.2	0.9	255.6
Total	$ 109.5	$ 148.4	$ 0.9	$ 258.8
Financial liabilities:				
Liquidity Option Agreement	$ --	$ --	$ 245.1	$ 245.1
Interest rate derivatives	--	3.7	--	3.7
Commodity derivatives	31.3	109.2	2.5	143.0
Total	$ 31.3	$ 112.9	$ 247.6	$ 391.8

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

	Location	For the Nine Months Ended September 30, 2016	For the Nine Months Ended September 30, 2015
Financial asset (liability) balance, net, January 1		$ (246.7)	$ (219.3)
Total gains (losses) included in:			
Net income (1)	Revenue	0.7	(0.4)
Net income	Other expense, net	2.2	--
Other comprehensive income	Commodity derivative instruments – changes in fair value of cash flow hedges	1.5	(1.5)
Settlements	Revenue	(0.1)	(0.5)
Transfers out of Level 3		0.1	0.1
Financial asset (liability) balance, net, March 31		(242.3)	(221.6)
Total gains (losses) included in:			
Net income (1)	Revenue	--	(0.4)
Net income	Other expense, net	(23.3)	(11.5)
Other comprehensive income	Commodity derivative instruments – changes in fair value of cash flow hedges	2.0	(1.0)
Settlements	Revenue	(0.1)	0.2
Transfers out of Level 3		--	1.5
Financial asset (liability) balance, net, June 30		(263.7)	(232.8)
Total gains (losses) included in:			
Net income (1)	Revenue	0.2	(0.3)
Net income	Other expense, net	(6.9)	(4.3)
Other comprehensive income	Commodity derivative instruments – changes in fair value of cash flow hedges	(4.1)	(15.5)
Settlements	Revenue	(0.2)	0.3
Transfers out of Level 3		--	1.1
Financial asset (liability) balance, net, September 30		$ (274.7)	$ (251.5)

(1) There were $0.5 million of unrealized gains included in these amounts for the nine months ended September 30, 2016. There were unrealized losses of $1.1 million included in these amounts for the nine months ended September 30, 2015.

The following table provides quantitative information regarding our recurring Level 3 fair value measurements for commodity derivatives at September 30, 2016:

	Fair Value Financial Assets	Fair Value Financial Liabilities	Valuation Techniques	Unobservable Input	Range
Commodity derivatives – Crude oil	$ 1.4	$ 1.3	Discounted cash flow	Forward commodity prices	$45.44-$48.89/barrel
Commodity derivatives – Propane	5.8	6.5	Discounted cash flow	Forward commodity prices	$0.49-$0.57/gallon
Commodity derivatives – Natural gasoline	2.2	2.1	Discounted cash flow	Forward commodity prices	$1.06-$1.11/gallon
Commodity derivatives – Ethane	3.4	2.6	Discounted cash flow	Forward commodity prices	$0.23-$0.29/gallon
Commodity derivatives – Normal butane	1.6	3.5	Discounted cash flow	Forward commodity prices	$0.62-$0.73/gallon
Total	$ 14.4	$ 16.0			

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 September 30, 2016. 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

Long-lived assets (including intangible assets with finite useful lives and property, plant and equipment) are reviewed for impairment (i.e., subject to nonrecurring fair value measurements) when events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. Long-lived assets with carrying values that are not expected to be recovered through future cash flows are written-down to their estimated fair values. The following table summarizes our non-cash impairment charges by segment during each of the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	**2015**	**2016**	**2015**
NGL Pipelines & Services	$ 3.8	$ 14.6	$ 6.4	$ 20.6
Crude Oil Pipelines & Services	--	--	0.9	25.9
Natural Gas Pipelines & Services	2.0	--	11.7	21.5
Petrochemical & Refined Products Services	1.0	12.2	3.0	12.6
Offshore Pipelines & Services	--	--	--	58.5
Total	$ 6.8	$ 26.8	$ 22.0	$ 139.1

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

Our non-cash impairment charges for the nine months ended September 30, 2016 include $1.2 million related to other current assets, primarily spare parts and materials. The following table presents categories of long-lived assets, primarily property, plant and equipment, that were subject to non-recurring fair value measurements during the nine months ended September 30, 2016:

		Fair Value Measurements at the End of the Reporting Period Using			
	Carrying Value at September 30, 2016	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total Non-Cash Impairment Loss**
Long-lived assets disposed of other than by sale	$ --	$ --	$ --	$ --	$ 11.3
Long-lived assets held for sale	1.5	--	1.5	--	9.5
Total					$ 20.8

The following table presents categories of long-lived assets that were subject to non-recurring fair value measurements during the nine months ended September 30, 2015:

		Fair Value Measurements at the End of the Reporting Period Using			
	Carrying Value at September 30, 2015	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total Non-Cash Impairment Loss**
Long-lived assets disposed of other than by sale	$ 0.4	$ --	$ --	$ 0.4	$ 69.9
Long-lived assets held for sale	34.2	--	--	34.2	14.2
Long-lived assets disposed of by sale (1)	--	--	--	--	55.0
Total					$ 139.1

(1) Primarily represents the impairment charge recorded in connection with the sale of our Offshore Business.

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 $22.5 billion and $19.51 billion at September 30, 2016 and December 31, 2015, respectively. The aggregate carrying value of these debt obligations was $20.85 billion and $20.87 billion at September 30, 2016 and December 31, 2015, 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.

Note 13. Related Party Transactions

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
Revenues – related parties:				
Unconsolidated affiliates	$ 15.7	$ 13.9	$ 44.5	$ 27.3
Costs and expenses – related parties:				
EPCO and its privately held affiliates	$ 242.3	$ 246.0	$ 721.0	$ 703.9
Unconsolidated affiliates	69.2	66.9	199.5	165.3
Total	$ 311.5	$ 312.9	$ 920.5	$ 869.2

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

	September 30, 2016	December 31, 2015
Accounts receivable - related parties:		
Unconsolidated affiliates	$ 1.7	$ 1.2
Accounts payable - related parties:		
EPCO and its privately held affiliates	$ 81.9	$ 75.6
Unconsolidated affiliates	15.8	8.5
Total	$ 97.7	$ 84.1

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

Relationship with EPCO and Affiliates

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

At September 30, 2016, 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
685,481,428	32.6%

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 September 30, 2016. 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 nine months ended September 30, 2016 and 2015, we paid EPCO and its privately held affiliates cash distributions totaling $793.6 million and $705.9 million, respectively. Distributions paid during 2015 excluded 35,380,000 Designated Units (see Note 8).

In January 2016, privately held affiliates of EPCO purchased 3,830,256 common units from us under our ATM program, generating gross proceeds of $100 million. In February 2016, privately held affiliates of EPCO reinvested $100 million through our DRIP, resulting in the issuance of an additional 4,481,504 of our common units. See Note 8 for additional information regarding our ATM program and DRIP.

We have no employees. All of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to the ASA or by other service providers. The following table presents our related party costs and expenses attributable to the ASA with EPCO for the periods indicated:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	**2015**	**2016**	**2015**
Operating costs and expenses	$ 212.9	$ 215.3	$ 628.9	$ 612.2
General and administrative expenses	25.9	26.4	79.5	78.8
Total costs and expenses	$ 238.8	$ 241.7	$ 708.4	$ 691.0

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 September 30, 2016 and December 31, 2015, our accruals for litigation contingencies were $5.6 million and $4.6 million, respectively, and were recorded in our Unaudited Condensed Consolidated Balance Sheets as a component of "Other current liabilities." Our evaluation of litigation contingencies is based on the facts and circumstances of each case and predicting the outcome of these matters involves uncertainties. In the event the assumptions we use to evaluate these matters change in future periods or new information becomes available, we may be required to record additional accruals. In an effort to mitigate expenses associated with litigation, we may settle legal proceedings out of court.

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

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

We do not believe that the verdict or the judgment entered against us is supported by the evidence or the law. 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 has now been submitted to the Court of Appeals for its consideration. We intend to vigorously oppose the judgment through the appeals process. As of September 30, 2016, we have not recorded a provision for this matter as management believes payment of damages in this case is not probable.

FTC Inquiry regarding Oiltanking Acquisition
On February 23, 2015, we received a Civil Investigative Demand and a related Subpoena Duces Tecum from the Federal Trade Commission ("FTC") requesting specified information relating to the Oiltanking acquisition and our operations. On April 13, 2015, we received a Civil Investigative Demand issued by the Attorney General of the State of Texas requesting copies of the same information and any correspondence with the FTC. In a letter dated August 10, 2016 and published by the FTC on August 19, 2016, the FTC announced, "[u]pon further review of this matter, it now appears that no further action is warranted by the Commission at this time. Accordingly, the investigation has been closed." Contemporaneously, the Attorney General of the State of Texas closed its investigation of the Oiltanking acquisition.

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 ("OPD"), 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. This case has yet to be set for trial, and we intend to diligently prosecute these claims and seek all direct, consequential, and exemplary damages to which we may be entitled.

Contractual Obligations

<u>Scheduled Maturities of Debt</u>
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.

<u>Operating Lease Obligations</u>
Consolidated lease and rental expense was $27.0 million and $28.8 million during the three months ended September 30, 2016 and 2015, respectively. For the nine months ended September 30, 2016 and 2015, consolidated lease and rental expense was $81.8 million and $76.4 million, respectively. Our operating lease commitments at September 30, 2016 did not differ materially from those reported in our 2015 Form 10-K.

<u>Purchase Obligations</u>
Our consolidated purchase obligations at September 30, 2016 did not differ materially from those reported in our 2015 Form 10-K.

Liquidity Option Agreement
We entered into a put option agreement (the "Liquidity Option Agreement") with OTA and Marquard & Bahls ("M&B") in connection with the Oiltanking acquisition. Under the Liquidity Option Agreement, we granted M&B the option to sell to us 100% of the issued and outstanding capital stock of OTA at any time within a 90-day period commencing on February 1, 2020. At that time, OTA's only significant asset is expected to be the 54,807,352 Enterprise common units it received in Step 1 of the Oiltanking acquisition, to the extent that such common units are not sold by M&B prior to the option exercise date pursuant to a related registration rights agreement.

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 will recognize expense for the difference.

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 is based on several inputs that are not observable in the market (i.e., Level 3 inputs). For example, the fair value of the Liquidity Option at September 30, 2016 was estimated at $273.1 million and was based on the following Level 3 inputs:

- 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 will 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 September 30, 2016, we used a market rate commensurate with level of debt and tenure of approximately 4.75%. If the assumption of debt is excluded from the valuation model (and all other inputs are the same), the estimated fair value of the Liquidity Option would increase by $211.1 million at September 30, 2016;

- Forecasted annual growth rates of Enterprise's taxable earnings before interest, taxes, depreciation and amortization ranging from 2% to 15%;

- 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 September 30, 2016, we used ownership interests ranging from 1.9% to 2.6%;

- A forecasted yield on Enterprise common units of 5.8% to 6.6%;

- OTA pays an aggregate federal and state income tax rate of 38% on its taxable income; and

- A discount rate of 7.5% based on our weighted-average cost of capital at September 30, 2016.

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 September 30, 2016, based on these scenarios, we expect that OTA would own approximately 83% of the 54,807,352 Enterprise common units it received in Step 1 when the option period begins in February 2020. For sensitivity purposes, if 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 would increase by $56.7 million at September 30, 2016.

Changes in the fair value of the Liquidity Option are recognized in earnings as a component of other income (expense) on our Unaudited Statements of Consolidated Operations. Results for the three and nine months ended September 30, 2015 include $4.3 million and $15.8 million, respectively, of expense for the Liquidity Option. Results for the three and nine months ended September 30, 2016 include $6.9 million and $28.0 million, respectively, of aggregate non-cash expense attributable to accretion and changes in management estimates regarding inputs to the valuation model.

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 Nine Months Ended September 30, 2016	For the Nine Months Ended September 30, 2015
Decrease (increase) in:		
Accounts receivable – trade	$ (370.4)	$ 1,042.5
Accounts receivable – related parties	(0.2)	1.2
Inventories	(701.6)	(143.2)
Prepaid and other current assets	(71.8)	(32.7)
Other assets	(1.3)	2.1
Increase (decrease) in:		
Accounts payable – trade	(36.8)	(72.7)
Accounts payable – related parties	13.6	(38.6)
Accrued product payables	615.1	(1,248.4)
Accrued interest	(149.5)	(136.7)
Other current liabilities	201.1	(13.8)
Other liabilities	12.1	12.4
Net effect of changes in operating accounts	$ (489.7)	$ (627.9)

We incurred liabilities for construction in progress that had not been paid at September 30, 2016 and December 31, 2015 of $166.5 million and $472.8 million, respectively. Such amounts are not included under the caption "Capital expenditures" on the Unaudited Condensed Statements of Consolidated Cash Flows.

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

In July 2015, we purchased EFS Midstream from affiliates of Pioneer and Reliance for approximately $2.1 billion, which was payable in two installments. The initial payment of $1.1 billion was paid at closing on July 8, 2015. The second and final installment of $1.0 billion was paid on July 11, 2016 using a combination of cash on hand and proceeds from the issuance of short-term notes under EPO's commercial paper program.

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

	For the Nine Months Ended September 30,	
	2016	2015
Sale of Offshore Business	$ --	$ 1,528.6
Other cash proceeds	43.9	8.7
Total	$ 43.9	$ 1,537.3

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

	For the Nine Months Ended September 30,	
	2016	2015
Sale of Offshore Business	$ --	$ (12.6)
Net gains (losses) attributable to other asset sales	2.3	(2.1)
Total	$ 2.3	$ (14.7)

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
September 30, 2016

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
ASSETS							
Current assets:							
Cash and cash equivalents and restricted cash	$ 279.2	$ 59.6	$ (4.4)	$ 334.4	$ --	$ --	$ 334.4
Accounts receivable – trade, net	1,089.9	1,857.4	(3.2)	2,944.1	--	--	2,944.1
Accounts receivable – related parties	125.8	772.6	(895.0)	3.4	--	(1.7)	1.7
Inventories	1,426.3	339.5	(3.3)	1,762.5	--	--	1,762.5
Derivative assets	193.2	48.2	--	241.4	--	--	241.4
Prepaid and other current assets	268.9	199.9	(11.5)	457.3	0.2	--	457.5
Total current assets	3,383.3	3,277.2	(917.4)	5,743.1	0.2	(1.7)	5,741.6
Property, plant and equipment, net	4,608.0	28,510.0	1.4	33,119.4	--	--	33,119.4
Investments in unconsolidated affiliates	40,035.9	4,208.7	(41,557.4)	2,687.2	22,093.4	(22,093.4)	2,687.2
Intangible assets, net	706.6	3,215.0	(14.4)	3,907.2	--	--	3,907.2
Goodwill	459.5	5,285.7	--	5,745.2	--	--	5,745.2
Other assets	194.8	41.4	(178.9)	57.3	0.5	--	57.8
Total assets	$ 49,388.1	$ 44,538.0	$ (42,666.7)	$ 51,259.4	$ 22,094.1	$ (22,095.1)	$ 51,258.4
LIABILITIES AND EQUITY							
Current liabilities:							
Current maturities of debt	$ 2,838.0	$ 0.1	$ --	$ 2,838.1	$ --	$ --	$ 2,838.1
Accounts payable – trade	197.8	260.2	(4.4)	453.6	0.1	--	453.7
Accounts payable – related parties	886.0	123.1	(911.4)	97.7	1.7	(1.7)	97.7
Accrued product payables	1,594.4	1,496.0	(2.9)	3,087.5	--	--	3,087.5
Accrued interest	202.3	0.4	--	202.7	--	--	202.7
Derivative liabilities	371.7	92.5	--	464.2	--	--	464.2
Other current liabilities	85.3	348.7	(10.3)	423.7	--	0.7	424.4
Total current liabilities	6,175.5	2,321.0	(929.0)	7,567.5	1.8	(1.0)	7,568.3
Long-term debt	21,106.0	15.2	--	21,121.2	--	--	21,121.2
Deferred tax liabilities	3.7	45.7	(0.8)	48.6	--	3.0	51.6
Other long-term liabilities	33.8	351.5	(179.8)	205.5	273.1	--	478.6
Commitments and contingencies							
Equity:							
Partners' and other owners' equity	22,069.1	41,727.7	(41,729.4)	22,067.4	21,819.2	(22,067.4)	21,819.2
Noncontrolling interests	--	76.9	172.3	249.2	--	(29.7)	219.5
Total equity	22,069.1	41,804.6	(41,557.1)	22,316.6	21,819.2	(22,097.1)	22,038.7
Total liabilities and equity	$ 49,388.1	$ 44,538.0	$ (42,666.7)	$ 51,259.4	$ 22,094.1	$ (22,095.1)	$ 51,258.4

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Balance Sheet
December 31, 2015

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
ASSETS							
Current assets:							
Cash and cash equivalents and restricted cash	$ 14.4	$ 71.1	$ (50.6)	$ 34.9	$ --	$ --	$ 34.9
Accounts receivable – trade, net	811.3	1,755.8	2.8	2,569.9	--	--	2,569.9
Accounts receivable – related parties	59.0	795.4	(853.0)	1.4	--	(0.2)	1.2
Inventories	786.9	251.4	(0.2)	1,038.1	--	--	1,038.1
Derivative assets	150.4	108.2	--	258.6	--	--	258.6
Prepaid and other current assets	153.6	249.1	(7.1)	395.6	--	--	395.6
Total current assets	1,975.6	3,231.0	(908.1)	4,298.5	--	(0.2)	4,298.3
Property, plant and equipment, net	3,859.8	28,173.5	1.4	32,034.7	--	--	32,034.7
Investments in unconsolidated affiliates	38,655.0	4,067.3	(40,093.8)	2,628.5	20,540.2	(20,540.2)	2,628.5
Intangible assets, net	721.2	3,330.7	(14.7)	4,037.2	--	--	4,037.2
Goodwill	459.5	5,285.7	--	5,745.2	--	--	5,745.2
Other assets	145.1	47.9	(135.2)	57.8	0.5	--	58.3
Total assets	$ 45,816.2	$ 44,136.1	$ (41,150.4)	$ 48,801.9	$ 20,540.7	$ (20,540.4)	$ 48,802.2
LIABILITIES AND EQUITY							
Current liabilities:							
Current maturities of debt	$ 1,863.8	$ 0.1	$ --	$ 1,863.9	$ --	$ --	$ 1,863.9
Accounts payable – trade	375.3	535.1	(50.6)	859.8	0.3	--	860.1
Accounts payable – related parties	885.3	62.3	(863.5)	84.1	0.2	(0.2)	84.1
Accrued product payables	997.7	1,489.3	(2.6)	2,484.4	--	--	2,484.4
Accrued liability related to EFS Midstream acquisition	--	993.2	--	993.2	--	--	993.2
Accrued interest	352.0	0.1	--	352.1	--	--	352.1
Derivative liabilities	75.1	65.5	--	140.6	--	--	140.6
Other current liabilities	103.6	291.6	(7.0)	388.2	--	--	388.2
Total current liabilities	4,652.8	3,437.2	(923.7)	7,166.3	0.5	(0.2)	7,166.6
Long-term debt	20,661.6	15.3	--	20,676.9	--	--	20,676.9
Deferred tax liabilities	3.4	40.8	(0.8)	43.4	--	2.7	46.1
Other long-term liabilities	14.5	286.9	(135.0)	166.4	245.1	--	411.5
Commitments and contingencies							
Equity:							
Partners' and other owners' equity	20,483.9	40,297.2	(40,266.8)	20,514.3	20,295.1	(20,514.3)	20,295.1
Noncontrolling interests	--	58.7	175.9	234.6	--	(28.6)	206.0
Total equity	20,483.9	40,355.9	(40,090.9)	20,748.9	20,295.1	(20,542.9)	20,501.1
Total liabilities and equity	$ 45,816.2	$ 44,136.1	$ (41,150.4)	$ 48,801.9	$ 20,540.7	$ (20,540.4)	$ 48,802.2

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

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Revenues	$ 7,291.8	$ 3,932.4	$ (5,303.8)	$ 5,920.4	$ --	$ --	$ 5,920.4
Costs and expenses:							
Operating costs and expenses	7,099.6	3,270.3	(5,304.2)	5,065.7	--	--	5,065.7
General and administrative costs	6.3	35.0	0.2	41.5	0.5	--	42.0
Total costs and expenses	7,105.9	3,305.3	(5,304.0)	5,107.2	0.5	--	5,107.7
Equity in income of unconsolidated affiliates	701.6	129.3	(738.6)	92.3	642.0	(642.0)	92.3
Operating income	887.5	756.4	(738.4)	905.5	641.5	(642.0)	905.0
Other income (expense):							
Interest expense	(248.8)	(4.2)	2.1	(250.9)	--	--	(250.9)
Other, net	2.1	0.7	(2.1)	0.7	(6.9)	--	(6.2)
Total other expense, net	(246.7)	(3.5)	--	(250.2)	(6.9)	--	(257.1)
Income before income taxes	640.8	752.9	(738.4)	655.3	634.6	(642.0)	647.9
Provision for income taxes	(2.7)	(1.6)	--	(4.3)	--	(0.5)	(4.8)
Net income	638.1	751.3	(738.4)	651.0	634.6	(642.5)	643.1
Net income attributable to noncontrolling interests	--	(1.7)	(8.1)	(9.8)	--	1.3	(8.5)
Net income attributable to entity	$ 638.1	$ 749.6	$ (746.5)	$ 641.2	$ 634.6	$ (641.2)	$ 634.6

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

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Revenues	$ 4,685.2	$ 4,531.1	$ (2,908.4)	$ 6,307.9	$ --	$ --	$ 6,307.9
Costs and expenses:							
Operating costs and expenses	4,506.7	3,854.5	(2,908.6)	5,452.6	--	--	5,452.6
General and administrative costs	11.1	38.3	--	49.4	(0.4)	--	49.0
Total costs and expenses	4,517.8	3,892.8	(2,908.6)	5,502.0	(0.4)	--	5,501.6
Equity in income of unconsolidated affiliates	725.5	116.5	(738.9)	103.1	653.2	(653.2)	103.1
Operating income	892.9	754.8	(738.7)	909.0	653.6	(653.2)	909.4
Other income (expense):							
Interest expense	(239.5)	(4.2)	--	(243.7)	--	--	(243.7)
Other, net	1.7	0.1	--	1.8	(4.3)	--	(2.5)
Total other expense, net	(237.8)	(4.1)	--	(241.9)	(4.3)	--	(246.2)
Income before income taxes	655.1	750.7	(738.7)	667.1	649.3	(653.2)	663.2
Provision for income taxes	(3.3)	(2.2)	--	(5.5)	--	--	(5.5)
Net income	651.8	748.5	(738.7)	661.6	649.3	(653.2)	657.7
Net income attributable to noncontrolling interests	--	--	(9.7)	(9.7)	--	1.3	(8.4)
Net income attributable to entity	$ 651.8	$ 748.5	$ (748.4)	$ 651.9	$ 649.3	$ (651.9)	$ 649.3

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Operations
For the Nine Months Ended September 30, 2016

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Revenues	$ 19,847.9	$ 11,009.3	$ (14,313.7)	$ 16,543.5	$ --	$ --	$ 16,543.5
Costs and expenses:							
Operating costs and expenses	19,192.8	9,156.3	(14,314.3)	14,034.8	--	--	14,034.8
General and administrative costs	16.4	102.3	0.2	118.9	2.1	--	121.0
Total costs and expenses	19,209.2	9,258.6	(14,314.1)	14,153.7	2.1	--	14,155.8
Equity in income of unconsolidated affiliates	1,971.6	389.3	(2,091.1)	269.8	1,884.4	(1,884.4)	269.8
Operating income	2,610.3	2,140.0	(2,090.7)	2,659.6	1,882.3	(1,884.4)	2,657.5
Other income (expense):							
Interest expense	(726.4)	(14.8)	5.6	(735.6)	--	--	(735.6)
Other, net	6.0	2.1	(5.6)	2.5	(28.0)	--	(25.5)
Total other expense, net	(720.4)	(12.7)	--	(733.1)	(28.0)	--	(761.1)
Income before income taxes	1,889.9	2,127.3	(2,090.7)	1,926.5	1,854.3	(1,884.4)	1,896.4
Provision for income taxes	(5.5)	(6.2)	--	(11.7)	--	(1.4)	(13.1)
Net income	1,884.4	2,121.1	(2,090.7)	1,914.8	1,854.3	(1,885.8)	1,883.3
Net income attributable to noncontrolling interests	--	(5.3)	(27.6)	(32.9)	--	3.9	(29.0)
Net income attributable to entity	$ 1,884.4	$ 2,115.8	$ (2,118.3)	$ 1,881.9	$ 1,854.3	$ (1,881.9)	$ 1,854.3

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

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Revenues	$ 15,301.0	$ 14,751.0	$ (9,179.1)	$ 20,872.9	$ --	$ --	$ 20,872.9
Costs and expenses:							
Operating costs and expenses	14,696.2	12,909.8	(9,179.5)	18,426.5	--	--	18,426.5
General and administrative costs	28.9	113.9	--	142.8	0.4	--	143.2
Total costs and expenses	14,725.1	13,023.7	(9,179.5)	18,569.3	0.4	--	18,569.7
Equity in income of unconsolidated affiliates	1,996.4	314.5	(2,008.4)	302.5	1,852.6	(1,852.6)	302.5
Operating income	2,572.3	2,041.8	(2,008.0)	2,606.1	1,852.2	(1,852.6)	2,605.7
Other income (expense):							
Interest expense	(717.9)	(7.3)	2.0	(723.2)	--	--	(723.2)
Other, net	4.0	0.6	(2.0)	2.6	(15.8)	--	(13.2)
Total other expense, net	(713.9)	(6.7)	--	(720.6)	(15.8)	--	(736.4)
Income before income taxes	1,858.4	2,035.1	(2,008.0)	1,885.5	1,836.4	(1,852.6)	1,869.3
Benefit from (provision for) income taxes	(8.9)	5.4	--	(3.5)	--	(0.9)	(4.4)
Net income	1,849.5	2,040.5	(2,008.0)	1,882.0	1,836.4	(1,853.5)	1,864.9
Net loss (income) attributable to noncontrolling interests	--	0.8	(32.9)	(32.1)	--	3.6	(28.5)
Net income attributable to entity	$ 1,849.5	$ 2,041.3	$ (2,040.9)	$ 1,849.9	$ 1,836.4	$ (1,849.9)	$ 1,836.4

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

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Comprehensive income	$ 649.9	$ 738.0	$ (738.6)	$ 649.3	$ 632.9	$ (640.8)	$ 641.4
Comprehensive loss (income) attributable to noncontrolling interests	--	(1.7)	(8.1)	(9.8)	--	1.3	(8.5)
Comprehensive income attributable to entity	$ 649.9	$ 736.3	$ (746.7)	$ 639.5	$ 632.9	$ (639.5)	$ 632.9

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

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Comprehensive income	$ 676.0	$ 797.3	$ (763.9)	$ 709.4	$ 697.2	$ (701.0)	$ 705.6
Comprehensive income attributable to noncontrolling interests	--	--	(9.7)	(9.7)	--	1.3	(8.4)
Comprehensive income attributable to entity	$ 676.0	$ 797.3	$ (773.6)	$ 699.7	$ 697.2	$ (699.7)	$ 697.2

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

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Comprehensive income	$ 1,824.5	$ 2,091.6	$ (2,090.8)	$ 1,825.3	$ 1,764.8	$ (1,796.3)	$ 1,793.8
Comprehensive loss (income) attributable to noncontrolling interests	--	(5.3)	(27.6)	(32.9)	--	3.9	(29.0)
Comprehensive income attributable to entity	$ 1,824.5	$ 2,086.3	$ (2,118.4)	$ 1,792.4	$ 1,764.8	$ (1,792.4)	$ 1,764.8

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

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Comprehensive income	$ 1,869.9	$ 2,056.1	$ (2,033.2)	$ 1,892.8	$ 1,847.3	$ (1,864.3)	$ 1,875.8
Comprehensive loss (income) attributable to noncontrolling interests	--	0.8	(32.9)	(32.1)	--	3.6	(28.5)
Comprehensive income attributable to entity	$ 1,869.9	$ 2,056.9	$ (2,066.1)	$ 1,860.7	$ 1,847.3	$ (1,860.7)	$ 1,847.3

Enterprise Products Partners L.P.
Unaudited Condensed Consolidating Statement of Cash Flows
For the Nine Months Ended September 30, 2016

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	**Other Subsidiaries (Non-guarantor)**	**EPO and Subsidiaries Eliminations and Adjustments**	**Consolidated EPO and Subsidiaries**	**Enterprise Products Partners L.P. (Guarantor)**	**Eliminations and Adjustments**	**Consolidated Total**
Operating activities:							
Net income	$ 1,884.4	$ 2,121.1	$ (2,090.7)	$ 1,914.8	$ 1,854.3	$ (1,885.8)	$ 1,883.3
Reconciliation of net income to net cash flows provided by operating activities:							
Depreciation, amortization and accretion	131.9	1,023.7	(0.3)	1,155.3	--	--	1,155.3
Equity in income of unconsolidated affiliates	(1,971.6)	(389.3)	2,091.1	(269.8)	(1,884.4)	1,884.4	(269.8)
Distributions received on earnings from unconsolidated affiliates	733.1	196.9	(648.4)	281.6	2,477.3	(2,477.3)	281.6
Net effect of changes in operating accounts and other operating activities	1,281.6	(1,742.7)	46.1	(415.0)	22.9	0.7	(391.4)
Net cash flows provided by operating activities	2,059.4	1,209.7	(602.2)	2,666.9	2,470.1	(2,478.0)	2,659.0
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(989.6)	(1,420.2)	--	(2,409.8)	--	--	(2,409.8)
Cash used for business combinations, net of cash received	--	(1,000.0)	--	(1,000.0)	--	--	(1,000.0)
Proceeds from asset sales	27.9	16.0	--	43.9	--	--	43.9
Other investing activities	(2,177.0)	(84.2)	1,931.4	(329.8)	(2,161.2)	2,161.2	(329.8)
Cash used in investing activities	(3,138.7)	(2,488.4)	1,931.4	(3,695.7)	(2,161.2)	2,161.2	(3,695.7)
Financing activities:							
Borrowings under debt agreements	50,183.8	41.4	(41.4)	50,183.8	--	--	50,183.8
Repayments of debt	(48,776.4)	(0.1)	--	(48,776.5)	--	--	(48,776.5)
Cash distributions paid to owners	(2,477.3)	(677.5)	677.5	(2,477.3)	(2,448.3)	2,477.3	(2,448.3)
Cash payments made in connection with DERs	--	--	--	--	(8.5)	--	(8.5)
Cash distributions paid to noncontrolling interests	--	(7.3)	(29.1)	(36.4)	--	0.7	(35.7)
Cash contributions from noncontrolling interests	--	20.1	--	20.1	--	--	20.1
Net cash proceeds from issuance of common units	--	--	--	--	2,170.4	--	2,170.4
Cash contributions from owners	2,161.2	1,890.0	(1,890.0)	2,161.2	--	(2,161.2)	--
Other financing activities	(8.0)	--	--	(8.0)	(22.5)	--	(30.5)
Cash provided by financing activities	1,083.3	1,266.6	(1,283.0)	1,066.9	(308.9)	316.8	1,074.8
Net change in cash and cash equivalents	4.0	(12.1)	46.2	38.1	--	--	38.1
Cash and cash equivalents, January 1	--	69.6	(50.6)	19.0	--	--	19.0
Cash and cash equivalents, September 30	$ 4.0	$ 57.5	$ (4.4)	$ 57.1	$ --	$ --	$ 57.1

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

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Operating activities:							
Net income	$ 1,849.5	$ 2,040.5	$ (2,008.0)	$ 1,882.0	$ 1,836.4	$ (1,853.5)	$ 1,864.9
Reconciliation of net income to net cash flows provided by operating activities:							
Depreciation, amortization and accretion	106.0	1,042.1	(0.4)	1,147.7	--	--	1,147.7
Equity in income of unconsolidated affiliates	(1,996.4)	(314.5)	2,008.4	(302.5)	(1,852.6)	1,852.6	(302.5)
Distributions received on earnings from unconsolidated affiliates	1,705.4	227.1	(1,570.1)	362.4	2,241.1	(2,241.1)	362.4
Net effect of changes in operating accounts and other operating activities	(52.9)	(450.6)	9.3	(494.2)	12.0	0.9	(481.3)
Net cash flows provided by operating activities	1,611.6	2,544.6	(1,560.8)	2,595.4	2,236.9	(2,241.1)	2,591.2
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(725.5)	(1,893.6)	--	(2,619.1)	--	--	(2,619.1)
Cash used for business combinations, net of cash received	(1,058.4)	13.3	--	(1,045.1)	--	--	(1,045.1)
Proceeds from asset sales	1,532.1	5.2	--	1,537.3	--	--	1,537.3
Other investing activities	(1,091.2)	(43.5)	953.4	(181.3)	(1,005.2)	1,005.2	(181.3)
Cash used in investing activities	(1,343.0)	(1,918.6)	953.4	(2,308.2)	(1,005.2)	1,005.2	(2,308.2)
Financing activities:							
Borrowings under debt agreements	17,113.7	77.9	(77.9)	17,113.7	--	--	17,113.7
Repayments of debt	(16,139.2)	--	--	(16,139.2)	--	--	(16,139.2)
Cash distributions paid to owners	(2,241.1)	(1,602.4)	1,602.4	(2,241.1)	(2,185.1)	2,241.1	(2,185.1)
Cash payments made in connection with DERs	--	--	--	--	(5.6)	--	(5.6)
Cash distributions paid to noncontrolling interests	--	(0.8)	(32.4)	(33.2)	--	--	(33.2)
Cash contributions from noncontrolling interests	--	37.8	(0.4)	37.4	--	--	37.4
Net cash proceeds from issuance of common units	--	--	--	--	1,011.4	--	1,011.4
Cash contributions from owners	1,005.2	875.1	(875.1)	1,005.2	--	(1,005.2)	--
Other financing activities	(23.9)	--	--	(23.9)	(52.4)	--	(76.3)
Cash used in financing activities	(285.3)	(612.4)	616.6	(281.1)	(1,231.7)	1,235.9	(276.9)
Net change in cash and cash equivalents	(16.7)	13.6	9.2	6.1	--	--	6.1
Cash and cash equivalents, January 1	18.7	70.4	(14.7)	74.4	--	--	74.4
Cash and cash equivalents, September 30	$ 2.0	$ 84.0	$ (5.5)	$ 80.5	$ --	$ --	$ 80.5

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

For the Three and Nine Months Ended September 30, 2016 and 2015

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, 2015 (the "2015 Form 10-K"), as filed on February 26, 2016 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 32.6% of our limited partner interests at September 30, 2016.

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

References to "Offshore Business" refer to the Gulf of Mexico operations we sold to Genesis Energy, L.P. ("Genesis") in July 2015.

References to "EFS Midstream" mean EFS Midstream LLC, which we acquired in July 2015 from affiliates of Pioneer Natural Resources Company ("Pioneer") and Reliance Industries Limited ("Reliance").

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 third quarter of 2016 compared to the third quarter of 2015. Likewise, the phrase "period-to-period" means the nine months ended September 30, 2016 compared to the nine months ended September 30, 2015.

Cautionary Statement Regarding Forward-Looking Information

This quarterly report on Form 10-Q contains various forward-looking statements and information that are based on our beliefs and those of our general partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as "anticipate," "project," "expect," "plan," "seek," "goal," "estimate," "forecast," "intend," "could," "should," "would," "will," "believe," "may," "potential" and similar expressions and statements regarding our plans and objectives for future operations are intended to identify forward-looking statements. Although we and our general partner believe that our expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any assurances that such expectations will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions as described in more detail under "Risk Factors" within Part I, Item 1A included in our 2015 Form 10-K and within Part II, Item 1A of this quarterly report. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements. The forward-looking statements in this quarterly report speak only as of the filing date hereof. Except as required by federal and state securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason.

Overview of Business

We are a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "EPD." We were formed in April 1998 to own and operate certain natural gas liquid ("NGL") 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 midstream energy operations currently include: natural gas gathering, treating, processing, transportation and storage; NGL transportation, fractionation, storage, and import and export terminals (including liquefied petroleum gas, or "LPG"); crude oil gathering, transportation, storage and terminals; petrochemical and refined products transportation, storage and terminals, and related services; and a marine transportation business that operates primarily on the U.S. inland and Intracoastal Waterway systems. Our assets currently include approximately 49,000 miles of pipelines; 250 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. Like many publicly traded partnerships, we have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to an administrative services agreement ("ASA") or by other service providers.

Our historical operations are reported under five business segments: (i) NGL Pipelines & Services, (ii) Crude Oil Pipelines & Services, (iii) Natural Gas Pipelines & Services, (iv) Petrochemical & Refined Products Services and (v) Offshore Pipelines & Services. On July 24, 2015, we completed the sale of our Offshore Business, which primarily consisted of our Offshore Pipelines & Services segment. Our consolidated financial statements reflect ownership of the Offshore Business through July 24, 2015. See Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements for additional information regarding our business segments.

As a result of our acquisition of the member interests of EFS Midstream effective July 1, 2015, we began consolidating the financial statements of EFS Midstream as of that date.

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*.

Significant Recent Developments

Completion of Ethane Export Terminal on the Houston Ship Channel

In September 2016, we placed our ethane export terminal located at Morgan's Point on the Houston Ship Channel (the "Morgan's Point Ethane Export Terminal") into commercial service, and the terminal loaded its first vessel bound for Europe with 265,000 barrels of ethane. The Morgan's Point Ethane Export Terminal, which is the largest of its kind in the world, has an aggregate loading rate (nameplate capacity) of approximately 10,000 barrels per hour of fully refrigerated ethane. Supply for the Morgan's Point Ethane Export Terminal is sourced from our Mont Belvieu NGL fractionation and storage complex and transported through a new 18-mile, 24-inch diameter pipeline that we completed in February 2016.

The Morgan's Point Ethane Export Terminal supports growing international demand for abundant U.S. ethane from shale plays, which offers the global petrochemical industry a low-cost feedstock option and supply diversification. By providing producers with access to the export market, the Morgan's Point Ethane Export Terminal is also facilitating continued development of U.S. energy reserves.

Start-Up of Delaware Basin Gas Processing Plant

In August 2016, construction of our joint venture-owned Delaware Basin cryogenic natural gas processing plant (referred to as the "Waha" plant) was completed, and the facility was placed into service. The Waha plant, the construction of which is supported by long-term contracts, has a natural gas processing capacity of 150 MMcf/d and is able to extract in excess of 22 MBPD of NGLs. The plant is located in Reeves County, Texas and was designed to accommodate the growing production of NGL-rich natural gas from the Delaware Basin. We own a 50% equity interest in the joint venture that owns the Waha plant, which we operate.

In conjunction with the completion of the construction of the Waha plant, we completed construction of an 82-mile, 12-inch diameter pipeline that connects the Waha plant to our Chaparral Pipeline system, which transports mixed NGLs from natural gas processing plants in West Texas and New Mexico to our NGL fractionation and storage complex in Mont Belvieu, Texas. Our Texas Intrastate System provides transportation services for natural gas processed at the Waha plant.

Addition of Propylene Export Capability at our Houston Ship Channel terminal

In July 2016, we initiated polymer grade propylene ("PGP") loading services at our Enterprise Hydrocarbons Terminal ("EHT," formerly known as our "Houston Ship Channel LPG export terminal"), which is located on the Houston Ship Channel. We are expecting an increase in the number of PGP export cargoes in response to international demand. We now have the capability to load 5,000 metric tons per day of refrigerated PGP at the EHT dock facilities, which are directly supplied by propylene fractionators and storage wells at our Mont Belvieu, Texas complex.

Final Payment for EFS Midstream Acquisition

In July 2015, we purchased EFS Midstream from affiliates of Pioneer and Reliance for approximately $2.1 billion, which was payable in two installments. The initial payment of $1.1 billion was paid at closing on July 8, 2015. The second and final installment of $1.0 billion was paid on July 11, 2016 using a combination of cash on hand and proceeds from the issuance of short-term notes under EPO's commercial paper program.

Fire at Pascagoula Facility

In late June 2016, we experienced a fire at our Pascagoula natural gas processing plant located in Pascagoula, Mississippi (the "Pascagoula Facility"). This facility processes natural gas received from third-party production developments located in the northern Gulf of Mexico. We own and operate the Pascagoula Facility, which remains out of service as a result of damage sustained during the fire. Repairs to this location have commenced and the facility is expected to return to commercial service during the fourth quarter of 2016.

As a result of this event, we recorded a $7.1 million non-cash loss in the second quarter of 2016 attributable to assets damaged in the fire. In addition, we incurred $7.1 million of expense during the third quarter of 2016 for fire response activities at the Pascagoula Facility. We will capitalize those expenditures we incur to rebuild the facility.

Under our current insurance program, the standalone deductible for property damage claims is $55 million. We also have business interruption protection; however, such claims must involve physical damage and have a combined loss value in excess of $55 million and the period of interruption must exceed 60 days. We continue to evaluate the possibility of filing an insurance claim related to this event.

Expansion of Delaware Basin Network with New Natural Gas Processing Plant

In June 2016, we announced plans to build a second new cryogenic natural gas processing facility and associated natural gas and NGL pipeline infrastructure to facilitate continued growth of NGL-rich natural gas production in the Delaware Basin of West Texas and southeastern New Mexico. The site for the new processing plant, which will have a nameplate capacity of 300 MMcf/d and the capability to extract more than 40,000 barrels per day of NGL, has yet to be determined. The project is anchored by long-term commitments from a major producer. The facility, which we will own and operate, is expected to begin service in the second quarter of 2018.

In addition to providing new gas processing capabilities, the scope of the project will include construction of natural gas gathering lines, a pipeline to deliver residue natural gas to markets at the Waha hub, and an NGL pipeline to our Mid-America Pipeline System. These assets will be designed to integrate with the rest of our Delaware Basin infrastructure.

Start-Up of South Eddy Natural Gas Processing Plant

In May 2016, we announced that our new cryogenic natural gas processing plant located in Eddy County, New Mexico (the "South Eddy" plant) had been placed into service. We constructed the South Eddy plant to serve producers in the Delaware Basin region. The South Eddy plant has a nameplate natural gas processing capacity of 200 MMcf/d and is capable of extracting up to 25 MBPD of NGLs. We also completed construction of approximately 90 miles of natural gas gathering pipelines to supply the new plant.

In addition to the South Eddy plant and its related natural gas gathering infrastructure, we also completed a 71-mile extension of our Mid-America Pipeline System. This extension provides producers in the Delaware Basin with NGL takeaway capacity and direct access to our integrated network of NGL assets.

Results of Operations

Summarized Consolidated Income Statement Data

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
Revenues	$ 5,920.4	$ 6,307.9	$ 16,543.5	$ 20,872.9
Costs and expenses:				
Operating costs and expenses:				
Cost of sales	4,088.6	4,419.9	11,135.6	15,355.9
Other operating costs and expenses	612.1	642.5	1,787.2	1,834.8
Depreciation, amortization and accretion expenses	367.1	351.1	1,085.6	1,082.0
Net losses (gains) attributable to asset sales	(8.9)	12.3	(2.3)	14.7
Loss due to Pascagoula fire	--	--	7.1	--
Asset impairment charges	6.8	26.8	21.6	139.1
Total operating costs and expenses	5,065.7	5,452.6	14,034.8	18,426.5
General and administrative costs	42.0	49.0	121.0	143.2
Total costs and expenses	5,107.7	5,501.6	14,155.8	18,569.7
Equity in income of unconsolidated affiliates	92.3	103.1	269.8	302.5
Operating income	905.0	909.4	2,657.5	2,605.7
Interest expense	(250.9)	(243.7)	(735.6)	(723.2)
Change in fair market value of Liquidity Option Agreement	(6.9)	(4.3)	(28.0)	(15.8)
Other, net	0.7	1.8	2.5	2.6
Provision for income taxes	(4.8)	(5.5)	(13.1)	(4.4)
Net income	643.1	657.7	1,883.3	1,864.9
Net income attributable to noncontrolling interests	(8.5)	(8.4)	(29.0)	(28.5)
Net income attributable to limited partners	$ 634.6	$ 649.3	$ 1,854.3	$ 1,836.4

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 September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
NGL Pipelines & Services:				
Sales of NGLs and related products	$ 1,959.0	$ 1,844.9	$ 5,962.9	$ 5,936.2
Midstream services	457.9	441.9	1,373.3	1,293.0
Total	2,416.9	2,286.8	7,336.2	7,229.2
Crude Oil Pipelines & Services:				
Sales of crude oil	1,538.5	2,147.3	4,141.8	7,689.3
Midstream services	184.5	175.3	529.8	399.7
Total	1,723.0	2,322.6	4,671.6	8,089.0
Natural Gas Pipelines & Services:				
Sales of natural gas	483.7	455.0	1,104.4	1,361.2
Midstream services	230.5	254.7	695.5	767.1
Total	714.2	709.7	1,799.9	2,128.3
Petrochemical & Refined Products Services:				
Sales of petrochemicals and refined products	871.3	780.5	2,137.9	2,764.2
Midstream services	195.0	199.5	597.9	583.4
Total	1,066.3	980.0	2,735.8	3,347.6
Offshore Pipelines & Services:				
Sales of crude oil	--	0.4	--	3.2
Midstream services	--	8.4	--	75.6
Total	--	8.8	--	78.8
Total consolidated revenues	$ 5,920.4	$ 6,307.9	$ 16,543.5	$ 20,872.9

Selected Energy Commodity Price Data

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

	Natural Gas, $/MMBtu	Ethane, $/gallon	Propane, $/gallon	Normal Butane, $/gallon	Isobutane, $/gallon	Natural Gasoline, $/gallon	PGP, $/pound	Refinery Grade Propylene, $/pound	WTI Crude Oil, $/barrel	LLS Crude Oil, $/barrel
	(1)	(2)	(2)	(2)	(2)	(2)	(3)	(3)	(4)	(4)
2015 by quarter:										
1st Quarter	$2.99	$0.19	$0.53	$0.68	$0.68	$1.10	$0.50	$0.37	$48.63	$52.83
2nd Quarter	$2.65	$0.18	$0.46	$0.59	$0.60	$1.26	$0.42	$0.29	$57.94	$62.97
3rd Quarter	$2.77	$0.19	$0.40	$0.55	$0.55	$0.98	$0.33	$0.21	$46.43	$50.17
4th Quarter	$2.27	$0.18	$0.42	$0.60	$0.61	$0.97	$0.31	$0.18	$42.18	$43.54
2015 Averages	$2.67	$0.18	$0.45	$0.61	$0.61	$1.08	$0.39	$0.26	$48.80	$52.38
2016 by quarter:										
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
2016 Averages	$2.28	$0.18	$0.45	$0.59	$0.61	$0.90	$0.34	$0.20	$41.33	$43.00

(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) PGP 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. Crude oil, natural gas and NGL prices have been depressed since the fourth quarter of 2014 primarily due to an oversupply of these commodities on world markets. The weighted-average indicative market price for NGLs was $0.49 per gallon in the third quarter of 2016 versus $0.45 per gallon during the third quarter of 2015. Likewise, the weighted-average indicative market price for NGLs was $0.46 per gallon during the nine months ended September 30, 2016 compared to $0.50 per gallon during the same period in 2015.

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

We attempt to mitigate any commodity price exposure through our hedging activities as well as through converting keepwhole and similar contracts to fee-based arrangements. See Note 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
Third Quarter of 2016 Compared to Third Quarter of 2015. Total revenues for the third quarter of 2016 decreased $387.5 million when compared to total revenues for the third quarter of 2015. Revenues from the marketing of crude oil decreased $609.2 million quarter-to-quarter primarily due to lower sales volumes and prices, which accounted for $529.6 million and $79.6 million of the decrease, respectively. Revenues from the marketing of octane additives decreased $36.1 million quarter-to-quarter primarily due to lower sales prices. Revenues from the marketing of NGLs and refined products increased a net $203.0 million quarter-to-quarter primarily due to higher sales volumes, which accounted for a $270.9 million increase, partially offset by lower sales prices, which accounted for a $67.9 million decrease. Revenues from the marketing of natural gas and petrochemicals increased $67.7 million quarter-to-quarter primarily due to higher sales volumes and prices, which accounted for $41.3 million and $26.4 million of the increase, respectively.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. For the nine months ended September 30, 2016, total revenues decreased $4.33 billion when compared to total revenues for the nine months ended September 30, 2015. Revenues from the marketing of crude oil and natural gas decreased $3.81 billion period-to-period primarily due to lower sales volumes and prices, which accounted for a $2.02 billion decrease and a $1.79 billion decrease, respectively. Revenues from the marketing of NGLs, petrochemicals, refined products and octane additives decreased a net $558.8 million period-to-period primarily due to lower sales prices, which accounted for a $1.39 billion decrease, partially offset by an $829.6 million increase due to higher sales volumes.

Revenues from midstream services increased a net $77.7 million period-to-period primarily due to contributions from EFS Midstream, which were partially offset by a decrease due to the sale of our Offshore Business. Revenues increased $140.0 million period-to-period from the assets we acquired in the EFS Midstream acquisition in July 2015. Revenues from midstream services decreased $76.0 million period-to-period due to the sale of our Offshore Business in July 2015.

Operating costs and expenses
Third Quarter of 2016 Compared to Third Quarter of 2015. Total operating costs and expenses for the third quarter of 2016 decreased $386.9 million when compared to total operating costs and expenses for the third quarter of 2015. The cost of sales associated with our marketing of crude oil decreased $575.6 million quarter-to-quarter primarily due to lower sales volumes and purchase prices, which accounted for $467.9 million and $107.7 million of the decrease, respectively. The cost of sales associated with our marketing of natural gas and octane additives decreased a net $17.4 million quarter-to-quarter primarily due to lower purchase prices, which accounted for a $48.6 million decrease, partially offset by higher sales volumes, which accounted for a $31.2 million increase. The cost of sales associated with our marketing of NGLs and petrochemicals increased $176.6 million due to higher sales volumes and prices, which accounted for $133.0 million and $43.6 million of the increase, respectively. The cost of sales associated with our marketing of refined products increased a net $91.0 million quarter-to-quarter primarily due to higher sales volumes, which accounted for a $131.4 million increase, partially offset by lower purchase prices, which accounted for a $40.4 million decrease.

Other operating costs and expenses decreased a net $30.4 million quarter-to-quarter primarily due to lower maintenance expenses during the third quarter of 2016 when compared to the third quarter of 2015.

Depreciation, amortization and accretion expense in operating costs and expenses for the third quarter of 2016 increased $16.0 million quarter-to-quarter primarily due to assets we constructed and placed into service since the third quarter of 2015.

Operating costs and expenses also include $6.8 million and $26.8 million of non-cash asset impairment charges for the third quarters of 2016 and 2015, respectively. Our asset impairment charges for the third quarter of 2016 primarily relate to the planned abandonment of pipeline and storage assets in Texas. Our non-cash asset impairment charges for the third quarter of 2015 primarily relate to the planned abandonment of natural gas processing assets in southern Louisiana and the reclassification of certain marine vessels to held for sale status.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. For the nine months ended September 30, 2016, total operating costs and expenses decreased $4.39 billion when compared to the same period in 2015. The cost of sales associated with our marketing of crude oil decreased $3.33 billion period-to-period primarily due to lower sales volumes, which accounted for a $1.84 billion decrease, and lower purchase prices, which accounted for an additional $1.49 billion decrease. The cost of sales associated with our marketing of NGLs, natural gas, petrochemicals, refined products and octane additives decreased a net $886.9 million period-to-period primarily due to lower purchase prices, which accounted for a $1.57 billion decrease, partially offset by a $680.3 million increase due to higher sales volumes.

Other operating costs and expenses decreased a net $47.6 million period-to-period primarily due to lower maintenance expenses during the first nine months of 2016 when compared to the same period in 2015.

For the nine months ended September 30, 2016, depreciation, amortization and accretion expense in operating costs and expenses increased a net $3.6 million when compared to the nine months ended September 30, 2015. An $84.3 million decrease attributable to the sale of our Offshore Business was more than offset by an $87.9 million period-to-period increase primarily due to assets we constructed and placed into service or acquired since the second quarter of 2015.

Operating costs and expenses also include $21.6 million and $139.1 million of non-cash asset impairment charges for the nine months ended September 30, 2016 and 2015, respectively. We recorded a $54.8 million asset impairment charge in the second quarter of 2015 in connection with our sale of the Offshore Business. The remainder of our asset impairment charges for the nine months ended September 30, 2015 primarily relate to the abandonment of certain crude oil and natural gas pipeline assets in Texas.

General and administrative costs

General and administrative costs for the three and nine months ended September 30, 2016 decreased $7.0 million and $22.2 million, respectively, when compared to the same periods in 2015 primarily due to lower costs for employee compensation and professional services.

Equity in income of unconsolidated affiliates

Equity income from our unconsolidated affiliates for the third quarter of 2016 decreased a net $10.8 million when compared to third quarter of 2015. Results for the third quarter of 2015 included $5.4 million of equity earnings attributable to our former Offshore Business, which we sold in July 2015.

For the nine months ended September 30, 2016, equity income from our unconsolidated affiliates decreased a net $32.7 million when compared to the nine months ended September 30, 2015. Results for the nine months ended September 30, 2015 reflect $46.6 million of equity earnings attributable to the Offshore Business sold in July 2015. This period-to-period decrease was partially offset by a $13.8 million increase in earnings from our investments in crude oil pipelines, which benefited from the settlement of a rate case by the Seaway Crude Pipeline Company ("Seaway") during the first quarter of 2016.

Interest expense

Interest expense for the three and nine months ended September 30, 2016 increased $7.2 million and $12.4 million, respectively, when compared to the same periods in 2015. The following table presents the components of our consolidated interest expense for the periods indicated (dollars in millions):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	**2015**	**2016**	**2015**
Interest charged on debt principal outstanding	$ 273.8	$ 270.6	$ 815.8	$ 793.7
Impact of interest rate hedging program, including related amortization	8.1	3.2	22.2	12.1
Interest costs capitalized in connection with construction projects (1)	(38.9)	(40.3)	(127.8)	(105.6)
Other (2)	7.9	10.2	25.4	23.0
Total	$ 250.9	$ 243.7	$ 735.6	$ 723.2

(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) ratably 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, increased a net $3.2 million quarter-to-quarter primarily due to increased debt principal amounts outstanding during the third quarter of 2016, which accounted for a $16.1 million increase, partially offset by the effect of lower overall interest rates during the third quarter of 2016, which accounted for a $12.9 million decrease. Our weighted-average debt principal balance for the third quarter of 2016 was $23.69 billion compared to $22.45 billion for the third quarter of 2015. 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 nine months ended September 30, 2016, interest charged on debt principal outstanding increased a net $22.1 million period-to-period primarily due to increased debt principal amounts outstanding during the nine months ended September 30, 2016, which accounted for a $39.0 million increase, partially offset by the effect of lower overall interest rates in the nine months ended September 30, 2016, which accounted for a $16.9 million decrease. Our weighted-average debt principal balance for the nine months ended September 30, 2016 was $23.23 billion compared to $22.08 billion for the nine months ended September 30, 2015.

Change in fair value of Liquidity Option Agreement

Results for the three and nine months ended September 30, 2016 include $6.9 million and $28.0 million, respectively, of aggregate non-cash expense attributable to accretion and changes in management estimates regarding inputs to the valuation model for the Liquidity Option Agreement. 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 reflects our state tax obligations under the Revised Texas Franchise Tax. Our provision for income taxes for the third quarter of 2016 decreased $0.7 million when compared to the third quarter of 2015. For the nine months ended September 30, 2016, our provision for income taxes increased $8.7 million when compared to the nine months ended September 30, 2015 primarily due to a benefit we recorded in 2015 related to lower tax rates enacted by the State of Texas in June 2015.

Business Segment Highlights

We evaluate segment performance based on our financial measure of gross operating margin. 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 September 30, 2016	For the Three Months Ended September 30, 2015	For the Nine Months Ended September 30, 2016	For the Nine Months Ended September 30, 2015
Gross operating margin by segment:				
NGL Pipelines & Services	$ 703.5	$ 695.5	$ 2,206.3	$ 2,041.3
Crude Oil Pipelines & Services	254.0	254.6	633.7	704.2
Natural Gas Pipelines & Services	178.5	192.4	533.6	588.3
Petrochemical & Refined Products Services	171.6	191.5	501.9	547.4
Offshore Pipelines & Services	--	7.1	--	97.5
Total segment gross operating margin (1)	1,307.6	1,341.1	3,875.5	3,978.7
Net adjustment for shipper make-up rights	4.4	7.5	15.0	6.0
Total gross operating margin	$ 1,312.0	$ 1,348.6	$ 3,890.5	$ 3,984.7

(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 under Note 9 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

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 in compliance with recently issued guidance from the SEC. The GAAP financial measure most directly comparable to total gross operating margin is operating income. See "Other Items – Non-GAAP Reconciliations" within this Part I, Item 2 for reconciliations of gross operating margin to operating income for each period presented.

Each of our business segments benefit 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 quarterly and year-to-date segment results (i.e., our gross operating margin by segment amounts) and the primary drivers of such changes. The volume statistics presented in the tabular information for each segment are reported on a net basis, taking into account our ownership interests in certain joint ventures, and reflect the periods in which we owned an interest in such operations. These statistics reflect volumes for newly constructed assets from the dates such assets were placed into service.

NGL Pipelines & Services

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	**2015**	**2016**	**2015**
Segment gross operating margin:				
Natural gas processing and related NGL marketing activities	$ 203.3	$ 203.2	$ 618.5	$ 663.7
NGL pipelines, storage and terminals	377.9	366.1	1,212.8	1,006.0
NGL fractionation	122.3	126.2	375.0	371.6
Total	$ 703.5	$ 695.5	$ 2,206.3	$ 2,041.3
Selected volumetric data:				
NGL pipeline transportation volumes (MBPD)	2,854	2,831	2,933	2,647
NGL marine terminal volumes (MBPD)	373	324	439	294
NGL fractionation volumes (MBPD)	791	837	822	819
Equity NGL production (MBPD) (1)	116	129	136	129
Fee-based natural gas processing (MMcf/d) (2)	4,578	5,035	4,857	4,911

(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

Third Quarter of 2016 Compared to Third Quarter of 2015. Gross operating margin from natural gas processing and related NGL marketing activities for the third quarter of 2016 increased $0.1 million when compared to the third quarter of 2015.

Gross operating margin from our NGL marketing activities increased a net $13.5 million quarter-to-quarter primarily due to higher sales volumes, which accounted for a $58.0 million increase, partially offset by a $44.5 million decrease due to lower sales margins. Results from NGL marketing's export-oriented activities increased $20.5 million quarter-to-quarter primarily due to higher sales volumes, which support the utilization and recent expansion of EHT. Gross operating margin from NGL marketing activities in support of our transportation, storage and plant assets decreased a combined $7.0 million quarter-to-quarter.

Our recently completed South Eddy and Waha natural gas processing plants in the Delaware Basin region contributed $2.1 million of gross operating margin for the third quarter of 2016.

Gross operating margin from our natural gas processing plants in Louisiana and Mississippi decreased a combined $14.8 million quarter-to-quarter primarily due to $7.1 million in expense associated with fire response activities at our Pascagoula Facility and a $4.9 million decrease attributable to lower aggregate processing volumes. We experienced a fire at our Pascagoula plant in late June 2016. Equity NGL production and fee-based natural gas processing volumes at our Louisiana and Mississippi plants decreased a combined 8 MBPD and 195 MMcf/d, respectively.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. For the nine months ended September 30, 2016, gross operating margin from natural gas processing and related NGL marketing activities decreased $45.2 million when compared to the same period in 2015.

Gross operating margin from our natural gas processing plants decreased $97.1 million period-to-period. Collectively, gross operating margin from our Meeker, Pioneer, Chaco and Carlsbad plants decreased $48.7 million period-to-period primarily due to lower processing margins, including the impact of our related hedging activities. Gross operating margin from our South Texas plants decreased $41.9 million period-to-period attributable to lower average processing fees and margins, which accounted for a combined $31.3 million decrease, and lower fee-based processing volumes of 207 MMcf/d. Gross operating margin from our natural gas processing plants in Louisiana and Mississippi decreased a combined $13.5 million period-to-period primarily due to higher operating expenses, including approximately $7.1 million of costs attributable to the fire at our Pascagoula Facility. Our recently completed South Eddy and Waha plants in the Delaware Basin region contributed $3.5 million of gross operating margin for the first nine months of 2016.

Gross operating margin from our NGL marketing activities increased a net $51.9 million period-to-period primarily due to higher sales volumes, which accounted for a $181.8 million increase, partially offset by a $129.9 million decrease due to lower sales margins. Results from NGL marketing's export-oriented activities increased $98.2 million period-to-period, which was partially offset by a $46.3 million net decrease in gross operating margin from NGL marketing's activities in support of our transportation, storage and plant assets.

NGL pipelines, storage and terminals

Third Quarter of 2016 Compared to Third Quarter of 2015. Gross operating margin from NGL pipelines, storage and terminal assets for the third quarter of 2016 increased $11.8 million when compared to the third quarter of 2015. Gross operating margin from our ATEX and Aegis Ethane Pipelines increased a combined $26.5 million quarter-to-quarter primarily due to a combined 112 MBPD increase in transportation volumes. Volumes on ATEX increased 36 MPBD quarter-to-quarter primarily due to expected contractual increases from anchor shippers on the system. Volumes on Aegis increased 76 MBPD quarter-to-quarter. The second segment of our Aegis Ethane Pipeline was placed into service in September 2015, and the third and final segment was placed into service in December 2015.

Gross operating margin from EHT and a related pipeline increased $8.8 million quarter-to-quarter primarily due to higher marine terminal and pipeline transportation volumes of 32 MBPD and 42 MBPD, respectively. Volumes at EHT were higher in 2016 when compared to 2015 primarily due to the completion of an expansion project at the terminal in December 2015 that increased our ability to load LPGs from 9.0 MMBbls per month to 16.0 MMBbls per month.

Gross operating margin from our Mid-America Pipeline System, Seminole Pipeline and related terminals decreased $12.7 million quarter-to-quarter primarily due to lower average transportation fees. Gross operating margin from our Dixie, South Louisiana, Tri-States and Rio Grande NGL Pipelines decreased a combined $11.2 million quarter-to-quarter primarily due to an aggregate 74 MBPD decrease in transportation volumes (net to our interest).

Gross operating margin from our Morgan's Point ethane export terminal, which was placed into commercial service in September 2016, was a loss of $3.2 million primarily due to commissioning costs.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. For the nine months ended September 30, 2016, gross operating margin from NGL pipelines, storage and terminal assets increased $206.8 million when compared to the nine months ended September 30, 2015. Gross operating margin from our ATEX and Aegis Ethane Pipelines increased a combined $87.4 million period-to-period primarily due to a combined 132 MBPD increase in transportation volumes. Gross operating margin from EHT and a related pipeline increased $76.3 million period-to-period primarily due to higher marine terminal and pipeline transportation volumes of 129 MBPD and 112 MBPD, respectively.

Gross operating margin from our NGL and related product storage complex in Mont Belvieu, Texas increased $18.2 million period-to-period primarily due to higher fees.

Gross operating margin from our Mid-America Pipeline System, Seminole Pipeline and related terminals increased $14.8 million period-to-period primarily due to higher transportation volumes of 45 MBPD. Gross operating margin from our South Texas NGL Pipeline System increased $11.5 million period-to-period primarily due to higher transportation fees, which escalated in January 2016.

NGL fractionation

Third Quarter of 2016 Compared to Third Quarter of 2015. Gross operating margin from NGL fractionation decreased $3.9 million quarter-to-quarter primarily due to lower fractionation volumes at our Mont Belvieu, Promix, Norco and Hobbs fractionators. Fractionation volumes decreased 46 MBPD quarter-to-quarter primarily due to increased ethane rejection during the third quarter of 2016 at regional natural gas processing facilities.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. Gross operating margin from NGL fractionation increased $3.4 million period-to-period primarily due to higher fractionation volumes of 7 MBPD at our Mont Belvieu complex for the nine months ended September 30, 2016 when compared to the nine months ended September 30, 2015.

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 September 30,		For the Nine Months Ended September 30,	
	2016	**2015**	**2016**	**2015**
Segment gross operating margin	$ 254.0	$ 254.6	$ 633.7	$ 704.2
Selected volumetric data:				
Crude oil pipeline transportation volumes (MBPD)	1,397	1,535	1,383	1,463
Crude oil marine terminal volumes (MBPD)	520	551	504	595

Third Quarter of 2016 Compared to Third Quarter of 2015. Gross operating margin from our Crude Oil Pipelines & Services segment decreased a net $0.6 million quarter-to-quarter primarily from variances attributable to our South Texas Crude Oil Pipeline System, crude oil marketing and related trucking activities, EFS Midstream assets and crude oil terminaling services.

Gross operating margin from our South Texas Crude Oil Pipeline System decreased $22.1 million quarter-to-quarter primarily due to lower average fees, which accounted for a $12.3 million decrease, and lower transportation volumes of 60 MBPD, which accounted for a $12.5 million decrease. Equity earnings from our investment in the Eagle Ford Crude Pipeline joint venture decreased $5.9 million quarter-to-quarter primarily due to lower transportation volumes of 38 MBPD (net to our interest). The decrease in crude oil transportation volumes on these systems is attributable to reduced producer drilling activity across the Eagle Ford Shale in South Texas. Gross operating margin from our crude oil marketing and related trucking activities decreased a net $5.7 million quarter-to-quarter primarily due to lower crude oil sales margins, which accounted for a $28.8 million decrease, partially offset by $23.2 million of non-cash mark-to-market gains recorded in the third quarter of 2016 on financial instruments related to blending activities.

Gross operating margin from our EFS Midstream system increased $14.5 million quarter-to-quarter primarily due to higher revenues, which accounted for a net $9.1 million increase, and a $5.4 million decrease in operating costs. Condensate volumes on our EFS Midstream system decreased 25 MBPD quarter-to-quarter reflecting reduced drilling activity in the region of the Eagle Ford Shale served by this system.

Gross operating margin from crude oil terminaling services at our Beaumont Marine West ("BMW") and Enterprise Crude Houston ("ECHO") and EHT facilities increased a combined $12.7 million quarter-to-quarter primarily due to expansion projects at these facilities (e.g., the construction of new storage tanks).

Equity earnings from our investment in Seaway increased $3.1 million quarter-to-quarter. Transportation volumes on the Seaway Pipeline decreased 29 MBPD quarter-to-quarter (net to our interest).

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. For the nine months ended September 30, 2016, gross operating margin from our Crude Oil Pipelines & Services segment decreased $70.5 million when compared to the nine months ended September 30, 2015.

Gross operating margin from our crude oil marketing and related trucking activities decreased $158.9 million period-to-period primarily due to lower crude oil sales margins, which accounted for a $121.4 million decrease, and $37.5 million of net non-cash mark-to-market losses recorded in 2016 on financial instruments related to blending activities. As a result of lower crude oil prices, regional price spreads have been less than the costs incurred by our marketing business. This impact is more pronounced given that our crude oil marketing business has contracted for 75 MBPD of firm capacity on the Seaway Pipeline, of which 25 MBPD of capacity terminates June 1, 2017 and the remaining 50 MBPD terminates February 1, 2018. Sales margins on Seaway Pipeline-related capacity were $33.4 million lower in the nine months ended September 30, 2016 when compared to the same period in 2015.

Gross operating margin from our South Texas Crude Oil Pipeline System decreased $68.7 million period-to-period primarily due to a 67 MBPD decrease in volumes, which accounted for a $46.2 million decrease, and a $21.2 million decrease due to lower average transportation fees. As noted previously, the decrease in crude oil transportation volumes is attributable to reduced producer drilling activity in the Eagle Ford Shale. Gross operating margin from our EFS Midstream system, which we acquired effective July 1, 2015, increased $123.3 million period-to-period due to the timing of the acquisition of these assets. Gross operating margin for this system reflects nine months of ownership in 2016 versus three months in 2015.

Gross operating margin from crude oil terminaling services at our BMW and ECHO facilities increased a combined $29.0 million period-to-period primarily due to expansion projects.

Equity earnings from our investment in Seaway increased $16.2 million period-to-period primarily due to the settlement of a rate case with the Federal Energy Regulatory Commission ("FERC") in the first quarter of 2016. In February 2016, the FERC issued its decision regarding the various challenges to Seaway's committed and uncommitted rates in FERC Docket No. IS12-226-000. The FERC upheld the committed rates and rejected the claim that the committed rates should be reduced to cost-based levels. The FERC's rulings regarding the uncommitted rates were also largely favorable to Seaway. Seaway submitted a compliance filing in March 2016 calculating revised uncommitted rates consistent with the FERC's order. The compliance filing was not challenged and the FERC accepted the revised rates. On a 100% basis, Seaway recorded a $24.5 million benefit related to settlement of the rate case, with our 50% share of the benefit equating to $12.3 million. Transportation volumes on the Seaway Pipeline decreased 21 MBPD period-to-period (net to our interest).

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 September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
Segment gross operating margin	$ 178.5	$ 192.4	$ 533.6	$ 588.3
Selected volumetric data:				
Natural gas pipeline transportation volumes (BBtus/d)	12,130	12,387	12,053	12,459

Third Quarter of 2016 Compared to Third Quarter of 2015. Gross operating margin from our Natural Gas Pipelines & Services segment for the third quarter of 2016 decreased $13.9 million when compared to the third quarter of 2015. Gross operating margin from our Texas Intrastate System decreased $15.8 million quarter-to-quarter primarily due to lower revenues attributable to reduced producer drilling activity in the Eagle Ford Shale and Barnett Shale. Gross operating margin from our Jonah Gathering System decreased a net $2.2 million quarter-to-quarter primarily due to lower gathering volumes of 126 BBtus/d, which accounted for a $3.0 million decrease, partially offset by lower operating costs. Gross operating margin from our Carlsbad Gathering System increased a net $3.6 million quarter-to-quarter primarily due to higher gathering volumes of 192 BBtus/d. Gathering volumes on this system have increased as a result of increased producer interest in the Delaware Basin, which is also the location of our recently constructed South Eddy natural gas processing plant.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. For the nine months ended September 30, 2016, gross operating margin from our Natural Gas Pipelines & Services segment decreased $54.7 million when compared to the nine months ended September 30, 2015. Gross operating margin from our Texas Intrastate System decreased $34.5 million period-to-period primarily due to lower revenues attributable to decreased producer drilling activity in the Eagle Ford Shale and Barnett Shale. Gross operating margin from our Acadian Gas System decreased $10.6 million period-to-period primarily due to reduced transportation fees.

Gross operating margin from our San Juan Gathering System decreased $5.1 million period-to-period primarily due to a $6.4 million decrease in gathering fee revenues and a $5.7 million decrease due to lower gathering volumes of 78 BBtus/d, both of which were partially offset by an $8.5 million decrease in operating expenses. Gathering fees on the San Juan Gathering System, which are indexed to regional natural gas prices, decreased period-to-period due to lower average natural gas prices during the nine months ended September 30, 2016 when compared to the same period in 2015. Gross operating margin from our Carlsbad Gathering System increased $7.8 million period-to-period primarily due to higher gathering volumes of 132 BBtus/d.

Petrochemical & Refined Products Services

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	**2015**	**2016**	**2015**
Segment gross operating margin:				
Propylene fractionation and related activities	$ 57.3	$ 46.7	$ 162.2	$ 145.3
Butane isomerization and related operations	16.8	18.1	50.2	44.1
Octane enhancement and related plant operations	16.8	57.5	27.8	126.8
Refined products pipelines and related activities	71.3	53.0	232.4	183.3
Marine transportation and other	9.4	16.2	29.3	47.9
Total	$ 171.6	$ 191.5	$ 501.9	$ 547.4
Selected volumetric data:				
Propylene fractionation volumes (MBPD)	76	72	75	71
Butane isomerization volumes (MBPD)	113	108	112	90
Standalone DIB processing volumes (MBPD)	85	89	90	79
Octane additive and related plant production volumes (MBPD)	27	20	19	17
Pipeline transportation volumes, primarily refined products and petrochemicals (MBPD)	784	816	836	777
Refined products and petrochemical marine terminal volumes (MBPD)	354	387	381	362

Propylene fractionation and related activities

Third Quarter of 2016 Compared to Third Quarter of 2015. Gross operating margin from propylene fractionation and related marketing activities for the third quarter of 2016 increased $10.6 million when compared to the third quarter of 2015. Gross operating margin from our Mont Belvieu propylene fractionation plants, which includes margins from our polymer grade propylene exports, increased $18.6 million quarter-to-quarter primarily due to lower operating costs, which accounted for an $8.0 million increase, and higher propylene sales margins, which accounted for an additional $4.3 million increase. The quarter-to-quarter decrease in operating costs is attributable to major maintenance projects that were completed in 2015.

Pre-commissioning expenses (e.g., the training of future operating personnel) associated with our propane dehydrogenation ("PDH") facility totaled $6.8 million for the third quarter of 2016. We expect our PDH facility to commence commercial operations in the second quarter of 2017.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. For the nine months ended September 30, 2016, gross operating margin from propylene fractionation and related activities increased $16.9 million when compared to the nine months ended September 30, 2015. Gross operating margin from our Mont Belvieu propylene fractionation plants increased a net $27.9 million period-to-period primarily due to lower operating costs, which accounted for a $29.0 million increase, and higher propylene fractionation volumes of 4 MBPD, which accounted for an additional $7.1 million increase, partially offset by the effects of lower propylene sales margins, which accounted for a $16.6 million decrease. The increase in gross operating margin from our Mont Belvieu propylene plants was partially offset by $13.0 million of pre-commissioning expenses associated with our PDH facility during the first nine months of 2016.

Butane isomerization and deisobutanizer operations

Third Quarter of 2016 Compared to Third Quarter of 2015. Gross operating margin from butane isomerization and deisobutanizer ("DIB") operations decreased $1.3 million quarter-to-quarter primarily due to higher operating expenses. Butane isomerization volumes increased 5 MBPD and standalone DIB processing volumes decreased 4 MBPD quarter-to-quarter.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. For the nine months ended September 30, 2016, gross operating margin from this business increased $6.1 million when compared to the nine months ended September 30, 2015. This increase is primarily due to higher butane isomerization and standalone DIB processing volumes of 22 MBPD and 11 MBPD, respectively.

Octane enhancement and HPIB plant operations

Third Quarter of 2016 Compared to Third Quarter of 2015. Gross operating margin from our octane enhancement facility and high purity isobutylene ("HPIB") plant decreased a combined $40.7 million quarter-to-quarter, including the results of our related hedging activities. The decrease in gross operating margin for this business is primarily due to lower sales margins attributable to higher global inventories of gasoline products, thus reducing the demand for blend stocks.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. For the nine months ended September 30, 2016, gross operating margin from our octane enhancement facility and HPIB plant decreased $99.0 million when compared to the nine months ended September 30, 2015. This decrease is primarily due to lower sales margins, including the results of our related hedging activities.

Refined products pipelines and related activities

Third Quarter of 2016 Compared to Third Quarter of 2015. Gross operating margin from refined products pipelines and related marketing activities for the third quarter of 2016 increased $18.3 million when compared to the third quarter of 2015. Gross operating margin for the TE Products Pipeline and related terminals increased $14.3 million quarter-to-quarter primarily due to lower operating expenses, which includes a $7.1 million benefit in the third quarter of 2016 from the settlement of construction-related litigation at our Port Arthur terminal. Gross operating margin from refined products terminaling services at our facilities in Beaumont, Texas increased $9.2 million quarter-to-quarter primarily due to higher demand for storage and marine vessel loading services at these facilities. Gross operating margin from our refined products marketing activities decreased $3.0 million quarter-to-quarter primarily due to lower sales margins.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. For the nine months ended September 30, 2016, gross operating margin from refined products pipelines and related marketing activities increased $49.1 million when compared to the nine months ended September 30, 2015. Gross operating margin for the TE Products Pipeline and related terminals increased $23.8 million period-to-period primarily due to higher volumes, which accounted for a $12.9 million increase, and a $9.9 million decrease in operating expenses (including the $7.1 million benefit in the third quarter of 2016 noted previously). Interstate pipeline transportation volumes on our TE Products Pipeline increased a net 13 MBPD period-to-period primarily due to an increase in refined products transportation volumes. Intrastate refined products and petrochemical pipeline transportation volumes on our TE Products Pipeline increased a combined 39 MBPD period-to-period.

Gross operating margin from refined products terminaling services at our facilities in Beaumont, Texas increased $19.5 million period-to-period primarily due to higher demand for storage and marine vessel loading services. Gross operating margin from our refined products marketing activities increased $7.9 million period-to-period primarily due to higher sales margins.

Other

Third Quarter of 2016 Compared to Third Quarter of 2015. Gross operating margin from other activities decreased $6.8 million quarter-to-quarter primarily due to lower demand for marine transportation services attributable to the lower commodity pricing environment.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. For the nine months ended September 30, 2016, gross operating margin from other activities decreased $18.6 million when compared to the nine months ended September 30, 2015 primarily due to lower demand for marine transportation services attributable to the lower commodity pricing environment.

Offshore Pipelines & Services
We sold our Offshore Business to Genesis on July 24, 2015. The following table presents segment gross operating margin and selected volumetric data for the Offshore Pipelines & Services segment for the periods indicated (dollars in millions, volumes as noted):

	For the Three Months Ended September 30, 2015	For the Nine Months Ended September 30, 2015
Segment gross operating margin	$ 7.1	$ 97.5
Selected volumetric data:		
Natural gas transportation volumes (BBtus/d)	565	587
Crude oil transportation volumes (MBPD)	344	357
Platform natural gas processing (MMcf/d)	82	101
Platform crude oil processing (MBPD)	9	13

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 September 30, 2016, we had $3.52 billion of consolidated liquidity, which was comprised of $3.46 billion of available borrowing capacity under EPO's revolving credit facilities and $57.1 million of unrestricted cash on hand.

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

At September 30, 2016, the aggregate carrying value of our product inventories was $1.76 billion compared to $1.04 billion at December 31, 2015. Our inventories, and associated working capital commitments, have increased significantly since December 31, 2015 primarily due to our marketing groups taking advantage of contango opportunities using our storage assets. We expect to gradually settle these inventory positions (valued at approximately $1 billion) through the first quarter of 2017, with a corresponding decrease in working capital commitments and related debt. For additional information regarding our inventories, see Note 3 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Consolidated Debt
The following table presents scheduled maturities of our consolidated debt obligations outstanding at September 30, 2016 for the years indicated (dollars in millions):

		Scheduled Maturities of Debt					
	Total	Remainder of 2016	2017	2018	2019	2020	Thereafter
Commercial Paper Notes	$ 2,038.6	$ 2,038.6	$ --	$ --	$ --	$ --	$ --
Senior Notes	20,650.0	--	800.0	1,100.0	1,500.0	1,500.0	15,750.0
Junior Subordinated Notes	1,474.4	--	--	--	--	--	1,474.4
Total	$ 24,163.0	$ 2,038.6	$ 800.0	$ 1,100.0	$ 1,500.0	$ 1,500.0	$ 17,224.4

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.

Issuance of $1.25 Billion of Senior Notes in April 2016
In April 2016, EPO issued $575 million in principal amount of 2.85% senior notes due April 2021 ("Senior Notes RR"), $575 million in principal amount of 3.95% senior notes due February 2027 ("Senior Notes SS") and $100 million in principal amount of 4.90% reopened senior notes due May 2046 ("Senior Notes QQ"). Senior Notes RR, SS and QQ were issued at 99.898%, 99.760% and 95.516% of their principal amounts, respectively. We issued these senior notes using our 2013 Shelf (see "–Universal shelf registration statement" below).

Net proceeds from the issuance of these senior notes were used as follows: (i) the repayment of amounts then outstanding under EPO's commercial paper program, which included amounts we used to repay $750 million in principal amount of Senior Notes AA that matured in February 2016, and (ii) for general company purposes.

Enterprise Products Partners L.P. has unconditionally guaranteed these senior notes on an unsecured and unsubordinated basis. These senior notes rank equal with EPO's existing and future unsecured and unsubordinated indebtedness and are senior to any existing and future subordinated indebtedness of EPO. These senior notes are subject to make-whole redemption rights and were issued under an indenture containing certain covenants, which generally restrict EPO's ability (with certain exceptions) to incur debt secured by liens and engage in sale and leaseback transactions.

Renewal of 364-Day Credit Agreement
In September 2016, EPO amended its 364-Day Credit Agreement to extend its maturity date to September 2017. There are currently no principal amounts outstanding under this revolving credit agreement. Under the terms of the 364-Day 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, subject to the terms and conditions set forth therein. To the extent that principal amounts are outstanding at the maturity date, EPO may elect to have the entire principal balance then outstanding continued as a non-revolving term loan for a period of one additional year, payable in September 2018. The remaining terms of the 364-Day Credit Agreement, as amended, remain materially the same as those reported for the 364-Day Credit Agreement in our 2015 Form 10-K.

Issuance of Common Units
The following table summarizes the issuance of common units in connection with our underwritten equity offerings, 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):

	Number of Common Units Issued	Net Cash Proceeds Received
Three months ended March 31, 2016:		
Common units issued in connection with ATM program	35,396,147	$ 849.0
Common units issued in connection with DRIP and EUPP	7,282,006	162.5
Total common units issued for quarter	42,678,153	1,011.5
Three months ended June 30, 2016:		
Common units issued in connection with ATM program	33,249,033	800.2
Common units issued in connection with DRIP and EUPP	3,102,695	76.6
Total common units issued for quarter	36,351,728	876.8
Three months ended September 30, 2016:		
Common units issued in connection with ATM program	7,468,312	205.2
Common units issued in connection with DRIP and EUPP	2,949,857	76.9
Total common units issued for quarter	10,418,169	282.1
Total common units issued during the nine months ended September 30, 2016	89,448,050	$ 2,170.4

Privately held affiliates of EPCO invested an aggregate $200 million in us through our ATM program and the DRIP during the first quarter of 2016 (this amount being a component of the net cash proceeds presented in the preceding table).

Universal shelf registration statement
On May 12, 2016, we filed with the SEC a new universal shelf registration statement (the "2016 Shelf"), which was immediately effective and replaced our prior universal shelf registration statement filed with the SEC in June 2013 (the "2013 Shelf"). The 2016 Shelf allows (and the prior 2013 Shelf allowed) Enterprise Products Partners L.P. and EPO (each on a standalone basis) to issue an unlimited amount of equity and debt securities, respectively.

At-the-Market program

On July 11, 2016, we filed an amended registration statement 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. Pursuant to the ATM program, we may sell common units under an equity distribution agreement between Enterprise Products Partners L.P. and certain broker-dealers from time-to-time by means of ordinary brokers' transactions through the NYSE at market prices, in block transactions or as otherwise agreed to with the broker-dealer parties to the agreement. The new registration statement was declared effective on July 14, 2016 and replaced our prior registration statement with respect to the ATM program. Following the effectiveness of the new ATM registration statement and after taking into account the aggregate sales price of common units sold under the ATM program through September 30, 2016, we have the capacity to issue additional common units under the ATM program up to an aggregate sales price of $1.75 billion.

Distribution reinvestment plan

On May 12, 2016, we filed with the SEC a new registration statement in connection with our DRIP, which was immediately effective and amended a prior registration statement filed in March 2010. The new registration statement increased the aggregate number of our common units authorized for issuance under the DRIP from 140,000,000 to 240,000,000. 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. After taking into account the new registration statement and the number of common units issued under the DRIP through September 30, 2016, we have the capacity to issue an additional 102,121,274 common units under this plan.

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 September 30, 2016 and December 31, 2015, our restricted cash amounts were $277.3 million and $15.9 million, respectively. The balance at September 30, 2016 consisted of initial margin requirements of $48.9 million and variation margin requirements of $228.4 million. The initial margin requirements will be returned to us as the related derivative instruments are settled. Our variation margin requirements increased by $248.7 million since December 31, 2015 primarily due to higher forward commodity prices for NGLs and related hydrocarbons during 2016 relative to our short financial derivative positions in these products. 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 November 1, 2016, the investment-grade credit ratings of EPO's long-term senior unsecured debt securities were BBB+ from Standard and Poor's and Baa1 from Moody's. In addition, the credit ratings of EPO's short-term senior unsecured debt securities were A-2 from Standard and Poor's and P-2 from Moody's. Fitch Ratings issued non-solicited ratings of BBB+ and F-2 for EPO's long-term senior unsecured debt securities and short-term senior unsecured debt securities, respectively.

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

Cash Flows from Operating, Investing and Financing Activities

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

	For the Nine Months Ended September 30,	
	2016	**2015**
Net cash flows provided by operating activities	$ 2,659.0	$ 2,591.2
Cash used in investing activities	3,695.7	2,308.2
Cash provided by (used in) financing activities	1,074.8	(276.9)

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, petrochemicals 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 counterparties 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 2015 Form 10-K and under Part II, Item 1A of this quarterly report.

Comparison of Nine Months Ended September 30, 2016 with Nine Months Ended September 30, 2015

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 nine months ended September 30, 2016 increased $67.8 million when compared to the same period in 2015. The increase in cash provided by operating activities was primarily due to:

- a $138.2 million period-to-period increase in cash primarily due to the timing of cash receipts and payments related to operations; and

- a $10.4 million increase in cash attributable to higher partnership income in the nine months ended September 30, 2016 compared to the same period in 2015 (after adjusting our $18.4 million period-to-period increase in net income for changes in the non-cash items identified on our Unaudited Condensed Statements of Consolidated Cash Flows); partially offset by

- an $80.8 million period-to-period decrease in cash distributions received from unconsolidated affiliates primarily due to the sale of our Offshore Business in July 2015.

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

Investing Activities. Cash used in investing activities for the nine months ended September 30, 2016 increased $1.39 billion when compared to the same period in 2015 primarily due to:

- a $1.49 billion period-to-period decrease in proceeds from asset sales primarily due to the sale of our Offshore Business in July 2015, which generated $1.53 billion; and

- a $215.2 million period-to-period increase in restricted cash requirements; partially offset by

- a $209.3 million period-to-period decrease in capital spending for consolidated property, plant and equipment, net of contributions in aid of construction costs;

- $51.9 million of distributions received in connection with the return of capital from unconsolidated affiliates during 2016;

- a $45.1 million period-to-period decrease in cash used for business combinations; and

- a $10.8 million period-to-period decrease in investments in our unconsolidated affiliates.

Financing Activities. Cash provided by financing activities for the nine months ended September 30, 2016 was $1.07 billion compared to cash used in financing activities for the nine months ended September 30, 2015 of $276.9 million. The $1.35 billion period-to-period change in cash flow from financing activities was primarily due to:

- a $1.16 billion period-to-period increase in net cash proceeds from the issuance of common units. We issued an aggregate 89,448,050 common units in connection with our ATM program, DRIP and EUPP during the nine months ended September 30, 2016, which generated $2.17 billion of net cash proceeds. This compares to an aggregate 31,509,768 common units we issued in connection with these programs and plans during the same period in 2015, which collectively generated $1.01 billion of net cash proceeds; and

- a $432.8 million period-to-period increase in net borrowings under our consolidated debt agreements. EPO issued $1.25 billion and repaid $750.0 billion in principal amount of senior notes during the nine months ended September 30, 2016, compared to the issuance of $2.5 billion and repayment of $1.48 billion in principal amount of senior and junior notes during the nine months ended September 30, 2015. Net issuances under EPO's commercial paper program were $913.9 million during the nine months ended September 30, 2016 compared to net repayments of $40.8 million during the same period in 2015; partially offset by

- a $263.2 million period-to-period increase in cash distributions paid to limited partners during the nine months ended September 30, 2016 when compared to the same period in 2015. 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.

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 most master limited partnerships, our general partner has a non-economic ownership interest in us and is not entitled to receive any cash distributions from us based on IDRs or other equity interests.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
Net income attributable to limited partners (1)	$ 634.6	$ 649.3	$ 1,854.3	$ 1,836.4
Adjustments to GAAP net income attributable to limited partners to derive non-GAAP distributable cash flow:				
Add depreciation, amortization and accretion expenses	391.9	372.8	1,155.3	1,147.7
Add asset impairment charges	6.8	26.8	22.0	139.1
Add losses or subtract gains attributable to asset sales, insurance recoveries and related property damage, net	(8.9)	12.3	4.8	14.7
Add cash proceeds from asset sales and insurance recoveries (2)	16.0	1,531.4	43.9	1,537.3
Add changes in fair value of Liquidity Option Agreement (3)	6.9	4.3	28.0	15.8
Add or subtract changes in fair market value of derivative instruments	(26.2)	2.2	42.1	(7.7)
Add cash distributions received from unconsolidated affiliates (4)	99.0	96.9	333.5	362.4
Subtract equity in income of unconsolidated affiliates	(92.3)	(103.1)	(269.8)	(302.5)
Subtract sustaining capital expenditures (5)	(61.7)	(84.3)	(179.4)	(195.8)
Add deferred income tax expense or subtract benefit, as applicable	1.0	(1.6)	5.3	(13.3)
Other, net	11.3	(5.7)	31.7	(15.6)
Distributable cash flow	$ 978.4	$ 2,501.3	$ 3,071.7	$ 4,518.5
Total cash distributions paid to limited partners with respect to period	$ 855.4	$ 760.7	$ 2,521.8	$ 2,246.4
Cash distributions per unit declared by Enterprise GP with respect to period (6)	$ 0.405	$ 0.385	$ 1.20	$ 1.14
Total distributable cash flow retained by partnership with respect to period (7)	$ 123.0	$ 1,740.6	$ 549.9	$ 2,272.1
Distribution coverage ratio (8)	1.14x	3.23x	1.22x	1.98x

(1) For a discussion of significant changes in our comparative income statement amounts underlying net income attributable to limited partners, along with the primary drivers of such changes, see "Consolidated Income Statements Highlights" within this Part I, Item 2.

(2) For a discussion of significant changes in cash proceeds from asset sales and insurance recoveries as presented in the investing activities section of our Unaudited Condensed Statements of Consolidated Cash Flows, see "Cash Flows from Operating, Investing and Financing Activities" within this Part I, Item 2.

(3) For information regarding 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.

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

Designated Units Issued in Connection with Holdings Merger

In November 2010, we completed our merger with Enterprise GP Holdings L.P. (the "Holdings Merger"). In connection with the Holdings Merger, a privately held affiliate of EPCO agreed to temporarily waive the regular cash distributions it would otherwise receive from us with respect to a certain number of our common units it owns (the "Designated Units"). Distributions paid by us to this privately held affiliate of EPCO during 2015 excluded 35,380,000 Designated Units. The temporary distribution waiver expired in November 2015; therefore, distributions paid to partners during calendar year 2016 are payable on all outstanding common units.

Capital Spending

An important part of our business strategy involves expansion through growth capital projects, business combinations and investments in joint ventures. We believe that we are positioned to continue to expand our 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. In light of current business conditions, we expect that these opportunities will increase.

We began commercial service on approximately $2.1 billion of growth capital projects during the nine months ended September 30, 2016. These projects included our Morgan's Point Ethane Export Terminal, Waha and South Eddy natural gas processing facilities and the completion of over 2 MMBbls of additional crude oil storage capacity at our terminals in Houston and Beaumont. We expect to place another $400 million of projects into commercial service during the fourth quarter of 2016. In addition, we have approximately $5.2 billion of growth capital projects scheduled to be completed in 2017 and 2018 including our PDH facility, Midland-to-Sealy Pipeline and completion of joint venture-owned dock infrastructure in Corpus Christi designed to accommodate crude oil volumes.

We expect our organic growth capital expenditures for calendar year 2016 to approximate $2.8 billion and sustaining capital expenditures to approximate $250 million. These amounts exclude the $1.0 billion final installment for EFS Midstream paid in July 2016. Our forecast of capital spending for 2016 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 forecasted 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):

	For the Nine Months Ended September 30,	
	2016	2015
Step 2 of Oiltanking acquisition:		
Equity instruments (36,827,517 common units of Enterprise) (1)	$ --	$ 1,408.7
Acquisition of EFS Midstream (2)	1,000.0	1,045.1
Capital spending for property, plant and equipment, net: (3)		
Growth capital projects (4)	2,221.9	2,420.3
Sustaining capital projects (5)	187.9	198.8
Investments in unconsolidated affiliates	119.9	130.7
Other investing activities	0.4	5.3
Total capital spending	$ 3,530.1	$ 5,208.9

(1) Amount represents non-cash equity consideration we issued to complete Step 2 of the Oiltanking acquisition.

(2) Amount represents the initial and second payments for EFS Midstream in July 2015 and 2016, respectively. We acquired EFS Midstream in July 2015 for approximately $2.1 billion in cash, which was payable in two installments.

(3) 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 $34.1 million and $11.4 million for the nine months ended September 30, 2016 and 2015, 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.

(4) 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.

(5) 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 nine months ended September 30, 2016 involved projects at our Mont Belvieu complex. Fluctuations in spending for sustaining capital projects are explained in large part by the timing and cost of pipeline integrity and similar projects.

Comparison of Nine Months Ended September 30, 2016 with Nine Months Ended September 30, 2015

We acquired EFS Midstream in July 2015 for approximately $2.1 billion in cash payable in two installments. The initial installment of approximately $1.1 billion was paid in July 2015, with the final $1.0 billion payment made in July 2016.

In total, capital spending for property, plant and equipment decreased $209.3 million period-to-period primarily due to lower growth capital spending during the nine months ended September 30, 2016.

Growth capital spending at our EHT and ethane export facilities decreased a combined $195.7 million period-to-period. We completed two expansion projects during 2015 at our EHT facility that increased our ability to load cargos of fully refrigerated, low-ethane propane to approximately 16.0 MMBbls per month. In September 2016, we placed our Morgan's Point Ethane Export Terminal into service. Likewise, growth capital spending on our ethane header system between Corpus Christi, Texas and the Mississippi River in Louisiana decreased $187.7 million period-to-period. We completed the Aegis Ethane Pipeline (i.e., a component of our ethane header system) in December 2015.

Growth capital spending at our Mont Belvieu complex increased $129.2 million period-to-period primarily due to ongoing construction of our PDH facility. Currently, we expect construction of the PDH facility to be completed in the first quarter of 2017 with commercial operations expected to begin in the second quarter of 2017. Growth capital spending on our natural gas processing and related pipeline projects in the Delaware Basin increased a combined $38.0 million period-to-period. Our South Eddy natural gas processing plant and related pipeline infrastructure began operations in May 2016.

Investments in unconsolidated affiliates decreased $10.8 million period-to-period primarily due to the completion of expansion projects on our Eagle Ford Crude Oil Pipeline System during 2015.

Critical Accounting Policies and Estimates

A discussion of our critical accounting policies and estimates is included in our 2015 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

Use of Non-GAAP Financial Measures

Total 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.

As presented within Part I, Item 2 of this quarterly report, the term "total gross operating margin" represents GAAP operating income exclusive of (i) depreciation, amortization and accretion expenses, (ii) impairment charges, (iii) gains and losses attributable to asset sales, insurance recoveries and related property damage and (iv) general and administrative costs. 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. The GAAP financial measure most directly comparable to total gross operating margin is operating income.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
Total gross operating margin	$ 1,312.0	$ 1,348.6	$ 3,890.5	$ 3,984.7
Adjustments to reconcile total gross operating margin to operating income:				
Subtract depreciation, amortization and accretion expense amounts not reflected in gross operating margin	(367.1)	(351.1)	(1,085.6)	(1,082.0)
Subtract asset impairment charges not reflected in gross operating margin	(6.8)	(26.8)	(21.6)	(139.1)
Add net gains or subtract net losses attributable to asset sales, insurance recoveries and related property damage not reflected in gross operating margin	8.9	(12.3)	(4.8)	(14.7)
Subtract general and administrative costs not reflected in gross operating margin	(42.0)	(49.0)	(121.0)	(143.2)
Operating income	$ 905.0	$ 909.4	$ 2,657.5	$ 2,605.7

Distributable cash flow

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

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2016	2015	2016	2015
Distributable cash flow	$ 978.4	$ 2,501.3	$ 3,071.7	$ 4,518.5
Adjustments to reconcile distributable cash flow to net cash flows provided by operating activities:				
Add sustaining capital expenditures reflected in distributable cash flow	61.7	84.3	179.4	195.8
Subtract cash proceeds from asset sales reflected in distributable cash flow	(16.0)	(1,531.4)	(43.9)	(1,537.3)
Net effect of changes in operating accounts not reflected in distributable cash flow	(195.1)	(377.2)	(489.7)	(627.9)
Other, net	(15.2)	12.6	(58.5)	42.1
Net cash flows provided by operating activities	$ 813.8	$ 689.6	$ 2,659.0	$ 2,591.2

Contractual Obligations

Our consolidated principal debt obligations at September 30, 2016 were approximately $24.16 billion compared to $22.74 billion at December 31, 2015. 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.

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 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 2015 Form 10-K.

We assess the risk associated with each of our derivative instrument portfolios using a sensitivity analysis model. This approach measures the change in fair value of the derivative instrument portfolio based on a hypothetical 10% change in the underlying interest rates or quoted market prices on a particular day. In addition to these variables, the fair value of each portfolio is influenced by changes in the notional amounts of the instruments outstanding and the discount rates used to determine the present values. The sensitivity analysis approach does not reflect the impact that the same hypothetical price movement would have on the hedged exposures to which they relate. Therefore, the impact on the fair value of a derivative instrument resulting from a change in interest rates or quoted market prices (as applicable) would normally be offset by a corresponding gain or loss on the hedged debt instrument, inventory value or forecasted transaction assuming:

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

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

See Note 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 and basis swaps. The following table summarizes our portfolio of commodity derivative instruments outstanding at September 30, 2016 (volume measures as noted):

	Volume (1)		Accounting
Derivative Purpose	**Current** (2)	**Long-Term** (2)	**Treatment**
Derivatives designated as hedging instruments:			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction (Bcf)	24.4	3.3	Cash flow hedge
Forecasted sales of NGLs (MMBbls)	12.1	3.5	Cash flow hedge
Octane enhancement:			
Forecasted purchase of NGLs (MMBbls)	1.3	n/a	Cash flow hedge
Forecasted sales of octane enhancement products (MMBbls)	1.4	n/a	Cash flow hedge
Natural gas marketing:			
Forecasted purchases of natural gas for fuel (Bcf)	3.3	0.5	Cash flow hedge
Natural gas storage inventory management activities (Bcf)	8.2	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	78.2	2.3	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	99.0	7.0	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products (MMBbls)	0.3	n/a	Cash flow hedge
Forecasted sales of refined products (MMBbls)	0.4	n/a	Cash flow hedge
Refined products inventory management activities (MMBbls)	2.1	n/a	Fair value hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	7.4	n/a	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	11.5	n/a	Cash flow hedge
Crude oil inventory management activities (MMBbls)	0.2	n/a	Fair value hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (Bcf) (3,4)	98.2	20.9	Mark-to-market
NGL risk management activities (MMBbls) (4)	7.2	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (4)	28.5	0.9	Mark-to-market

(1) Volume for derivatives designated as hedging instruments reflects the total amount of volumes hedged whereas volume for derivatives not designated as hedging instruments reflects the absolute value of derivative notional volumes.

(2) The maximum term for derivatives designated as cash flow hedges, derivatives designated as fair value hedges and derivatives not designated as hedging instruments is December 2017, June 2017 and March 2020, respectively.

(3) Current and long-term volumes include 24.5 Bcf and 1.8 Bcf, respectively, of physical derivative instruments that are predominantly priced at a marked-based index plus a premium or minus a discount related to location differences.

(4) Reflects the use of derivative instruments to manage risks associated with transportation, processing and storage assets.

At September 30, 2016, 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 sales contracts 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 fair value of our natural gas marketing portfolio at the dates indicated (dollars in millions):

Scenario	Resulting Classification	Portfolio Fair Value at December 31, 2015	Portfolio Fair Value at September 30, 2016	Portfolio Fair Value at October 17, 2016
Fair value assuming no change in underlying commodity prices	*Asset (Liability)*	$ 0.1	$ (7.8)	$ (13.6)
Fair value assuming 10% increase in underlying commodity prices	*Liability*	(3.7)	(12.7)	(19.1)
Fair value assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	3.9	(2.9)	(8.1)

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

Scenario	Resulting Classification	Portfolio Fair Value at December 31, 2015	Portfolio Fair Value at September 30, 2016	Portfolio Fair Value at October 17, 2016
Fair value assuming no change in underlying commodity prices	*Asset (Liability)*	$ 69.6	$ (180.1)	$ (208.2)
Fair value assuming 10% increase in underlying commodity prices	*Asset (Liability)*	41.7	(263.3)	(286.7)
Fair value assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	97.4	(96.8)	(129.8)

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

Scenario	Resulting Classification	Portfolio Fair Value at December 31, 2015	Portfolio Fair Value at September 30, 2016	Portfolio Fair Value at October 17, 2016
Fair value assuming no change in underlying commodity prices	*Asset (Liability)*	$ 42.9	$ (41.8)	$ (55.3)
Fair value assuming 10% increase in underlying commodity prices	*Asset (Liability)*	25.9	(83.5)	(98.2)
Fair value assuming 10% decrease in underlying commodity prices	*Asset (Liability)*	60.0	(0.2)	(12.4)

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 fair value at a given date is based on a number of factors, including the number and types of derivatives outstanding at that date, the notional value of the swaps and associated interest rates.

Interest rate swaps exchange the stated interest rate paid on a notional amount of existing debt for the fixed or floating interest rate stipulated in the derivative instrument. The following table summarizes our portfolio of interest rate swaps at September 30, 2016 (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 1.27%	Fair value hedge

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

		Interest Rate Swap Portfolio Fair Value at		
Scenario	Resulting Classification	December 31, 2015	September 30, 2016	October 17, 2016
Fair value assuming no change in underlying interest rates	*Asset (Liability)*	$ (0.5)	$ 3.5	$ 3.4
Fair value assuming 10% increase in underlying interest rates	*Asset (Liability)*	(2.6)	2.4	2.3
Fair value assuming 10% decrease in underlying interest rates	*Asset*	1.7	4.6	4.5

The following table summarizes our portfolio of 30-year forward starting swaps outstanding at September 30, 2016. 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	$250.0	9/2017	1.91%	Cash flow hedge
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 fair value of our forward starting swap portfolio at the dates indicated (dollars in millions):

		Forward Starting Swap Portfolio Fair Value at		
Scenario	Resulting Classification	December 31, 2015	September 30, 2016	October 17, 2016
Fair value assuming no change in underlying interest rates	*Liability*	$ --	$ (16.3)	$ (0.3)
Fair value assuming 10% increase in underlying interest rates	*Asset*	--	5.4	11.6
Fair value assuming 10% decrease in underlying interest rates	*Liability*	--	(39.2)	(12.9)

As a result of market conditions in October 2016, we elected to terminate the forward starting swaps that were scheduled to settle in September 2017, which resulted in cash gains totaling $6.1 million. As cash flow hedges, gains on these derivative instruments will be reflected as a component of accumulated other comprehensive income and be amortized to earnings (as a decrease in interest expense) over the life of the associated future debt obligations beginning in September 2017.

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 third quarter of 2016, 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.

On occasion, we are assessed monetary sanctions by governmental authorities related to administrative or judicial proceedings involving environmental matters. We do not expect such expenditures to be material to our consolidated financial statements. In September 2016, we received a Notice of Violation from the New Mexico Environment Department in connection with air emissions at our Chaparral natural gas processing facility. The eventual resolution of these matters may result in monetary sanctions in excess of $0.1 million.

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 2015 Form 10-K, in addition to other information in such annual report. The risk factors set forth in our 2015 Form 10-K are important factors that could cause our actual results to differ materially from those contained in any written or oral forward-looking statements made by us or on our behalf.

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

The following table summarizes our repurchase activity during the nine months ended September 30, 2016:

Period	Total Number of Units Purchased	Average Price Paid per Unit	Total Number of Units Purchased as Part of Publicly Announced Plans	Maximum Number of Units That May Yet Be Purchased Under the Plans
February 2016 (1)	388,396	$ 22.96	--	--
May 2016 (2)	6,633	$ 25.79	--	--
August 2016 (3)	4,739	$ 27.06	--	--
September 2016 (4)	3,461	$ 26.04	--	--

(1) Of the 1,167,578 restricted common units that vested in February 2016 and converted to common units, 388,396 units were sold back to us by employees to cover related withholding tax requirements.

(2) Of the 20,850 restricted common units that vested in May 2016 and converted to common units, 6,633 units were sold back to us by employees to cover related withholding tax requirements.

(3) Of the 17,500 restricted common units that vested in August 2016 and converted to common units, 4,739 units were sold back to us by employees to cover related withholding tax requirements.

(4) Of the 8,250 restricted common units that vested in September 2016 and converted to common units, 3,461 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 our general partner in October 2014 in connection with the acquisition of Oiltanking. Dr. Flach is also a managing director of Oiltanking GmbH, which maintains a joint venture interest in Oiltanking Odfjell GmbH, which in turn owns a joint venture interest in the Exir Chemical Terminal ("ECT") in Iran. This interest results from an investment dating back to 2002. Oiltanking GmbH currently has the contractual right to vote for the appointment of one member of ECT's three-member board. Oiltanking GmbH provides no goods, services, technology, information or support to ECT and plays no role in the management or day-to-day operations of ECT.

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

Oiltanking GmbH maintains an internal compliance program to ensure compliance with all applicable sanctions regimes, including sanctions laws maintained by the 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.***

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

reference to Exhibit 2.2 to Form 8-K filed September 7, 2010).

2.10	Contribution Agreement, dated as of September 30, 2010, by and between Enterprise Products Company and Enterprise Products Partners L.P. (incorporated by reference to Exhibit 2.1 to Form 8-K filed October 1, 2010).
2.11	Agreement and Plan of Merger, dated as of April 28, 2011, by and among Enterprise Products Partners L.P., Enterprise Products Holdings LLC, EPD MergerCo LLC, Duncan Energy Partners L.P. and DEP Holdings, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed April 29, 2011).
2.12	Contribution and Purchase Agreement, dated as of October 1, 2014, by and among Enterprise Products Partners L.P., Oiltanking Holding Americas, Inc. and OTB Holdco, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed October 1, 2014).
2.13	Agreement and Plan of Merger, dated as of November 11, 2014, by and among Enterprise Products Partners L.P., Enterprise Products Holdings LLC, EPOT MergerCo LLC, Oiltanking Partners, L.P. and OTLP GP, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed November 12, 2014).
3.1	Certificate of Limited Partnership of Enterprise Products Partners L.P. (incorporated by reference to Exhibit 3.6 to Form 10-Q filed November 9, 2007).
3.2	Certificate of Amendment to Certificate of Limited Partnership of Enterprise Products Partners L.P., filed on November 22, 2010 with the Delaware Secretary of State (incorporated by reference to Exhibit 3.6 to Form 8-K filed November 23, 2010).
3.3	Sixth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated November 22, 2010 (incorporated by reference to Exhibit 3.2 to Form 8-K filed November 23, 2010).
3.4	Amendment No. 1 to Sixth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated effective as of August 11, 2011 (incorporated by reference to Exhibit 3.1 to Form 8-K filed August 16, 2011).
3.5	Amendment No. 2 to Sixth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated effective as of August 21, 2014 (incorporated by reference to Exhibit 3.1 to Form 8-K filed August 26, 2014).
3.6	Certificate of Formation of Enterprise Products Holdings LLC (formerly named EPE Holdings, LLC) (incorporated by reference to Exhibit 3.3 to Form S-1/A Registration Statement, Reg. No. 333-124320, filed by Enterprise GP Holdings L.P. on July 22, 2005).
3.7	Certificate of Amendment to Certificate of Formation of Enterprise Products Holdings LLC (formerly named EPE Holdings, LLC), filed on November 22, 2010 with the Delaware Secretary of State (incorporated by reference to Exhibit 3.5 to Form 8-K filed November 23, 2010).
3.8	Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products Holdings LLC dated effective as of September 7, 2011 (incorporated by reference to Exhibit 3.1 to Form 8-K filed September 8, 2011).
3.9	Company Agreement of Enterprise Products Operating LLC dated June 30, 2007 (incorporated by reference to Exhibit 3.3 to Form 10-Q filed August 8, 2007).
3.10	Certificate of Incorporation of Enterprise Products OLPGP, Inc., dated December 3, 2003 (incorporated by reference to Exhibit 3.5 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
3.11	Bylaws of Enterprise Products OLPGP, Inc., dated December 8, 2003 (incorporated by reference to Exhibit 3.6 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
4.1	Form of Common Unit certificate (incorporated by reference to Exhibit A to Exhibit 3.1 to Form 8-K filed August 16, 2011).
4.2	Indenture, dated as of March 15, 2000, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed March 10, 2000).
4.3	Second Supplemental Indenture, dated as of February 14, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 10-K filed March 31, 2003).

4.4	Third Supplemental Indenture, dated as of June 30, 2007, among Enterprise Products Operating L.P., as Original Issuer, Enterprise Products Partners L.P., as Parent Guarantor, Enterprise Products Operating LLC, as New Issuer, and U.S. Bank National Association, as successor Trustee (incorporated by reference to Exhibit 4.55 to Form 10-Q filed August 8, 2007).
4.5	Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed October 6, 2004).
4.6	Fourth Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 6, 2004).
4.7	Fifth Supplemental Indenture, dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed March 3, 2005).
4.8	Sixth Supplemental Indenture, dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed March 3, 2005).
4.9	Eighth Supplemental Indenture, dated as of July 18, 2006, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006).
4.10	Ninth Supplemental Indenture, dated as of May 24, 2007, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed May 24, 2007).
4.11	Tenth Supplemental Indenture, dated as of June 30, 2007, among Enterprise Products Operating L.P., as Original Issuer, Enterprise Products Partners L.P., as Parent Guarantor, Enterprise Products Operating LLC, as New Issuer, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.54 to Form 10-Q filed August 8, 2007).
4.12	Eleventh Supplemental Indenture, dated as of September 4, 2007, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed September 5, 2007).
4.13	Thirteenth Supplemental Indenture, dated as of April 3, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed April 3, 2008).
4.14	Sixteenth Supplemental Indenture, dated as of October 5, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.15	Seventeenth Supplemental Indenture, dated as of October 27, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed October 28, 2009).
4.16	Eighteenth Supplemental Indenture, dated as of October 27, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed October 28, 2009).
4.17	Nineteenth Supplemental Indenture, dated as of May 20, 2010, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells

Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed May 20, 2010).

4.18	Twentieth Supplemental Indenture, dated as of January 13, 2011, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed January 13, 2011).
4.19	Twenty-First Supplemental Indenture, dated as of August 24, 2011, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed August 24, 2011).
4.20	Twenty-Second Supplemental Indenture, dated as of February 15, 2012, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.25 to Form 10-Q filed May 10, 2012).
4.21	Twenty-Third Supplemental Indenture, dated as of August 13, 2012, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed August 13, 2012).
4.22	Twenty-Fourth Supplemental Indenture, dated as of March 18, 2013, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed March 18, 2013).
4.23	Twenty-Fifth Supplemental Indenture, dated as of February 12, 2014, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed February 12, 2014).
4.24	Twenty-Sixth Supplemental Indenture, dated as of October 14, 2014, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed October 14, 2014).
4.25	Twenty-Seventh Supplemental Indenture, dated as of May 7, 2015, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed May 7, 2015).
4.26	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).
4.27	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).
4.28	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).
4.29	Form of Global Note representing \$250.0 million principal amount of 5.00% Series B Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.31 to Form 10-Q filed November 4, 2005).
4.30	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).
4.31	Form of Junior Subordinated Note, including Guarantee (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006).
4.32	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).
4.33	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).

4.34	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).
4.35	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).
4.36	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).
4.37	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).
4.38	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).
4.39	Form of Global Note representing $400.0 million principal amount of 3.70% Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed May 20, 2010).
4.40	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).
4.41	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).
4.42	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).
4.43	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).
4.44	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).
4.45	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).
4.46	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).
4.47	Form of Global Note representing $650.0 million principal amount of 1.25% Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed August 13, 2012).
4.48	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).
4.49	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).
4.50	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).
4.51	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).

4.52	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).
4.53	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).
4.54	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).
4.55	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).
4.56	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).
4.57	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).
4.58	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).
4.59	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).
4.60	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).
4.61	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).
4.62	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).
4.63	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).
4.64	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).
4.65	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).
4.66	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).
4.67	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).
4.68	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).

4.69	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).
4.70	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).
4.71	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).
4.72	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).
4.73	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).
4.74	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).
4.75	Full Release of Guarantee, dated November 23, 2009, of TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P. by U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.64 to Form 10-K filed on March 1, 2010).
4.76	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).
4.77	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).
4.78	Second Supplemental Indenture, dated as of June 30, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Existing Subsidiary Guarantors, TE Products Pipeline Company, LLC and TEPPCO Midstream Companies, LLC, as New Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TE Products Pipeline Company, LLC on July 6, 2007).
4.79	Third Supplemental Indenture, dated as of October 27, 2009, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Mellon Trust Company, N.A., as Trustee

	(incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TEPPCO Partners, L.P. on October 28, 2009).
4.80	Full Release of Guarantee, dated as of November 23, 2009, of TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P. by The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.70 to Form 10-K filed on March 1, 2010).
4.81	Registration Rights Agreement by and between Enterprise Products Partners L.P. and Oiltanking Holding Americas, Inc. dated as of October 1, 2014 (incorporated by reference to Exhibit 4.1 to Form 8-K filed on October 1, 2014).
10.1	Equity Distribution Agreement, dated August 3, 2016, by and among Enterprise Products Partners L.P., Enterprise Products OLPGP, Inc., Enterprise Products Operating LLC and Citigroup Global Markets Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Barclays Capital Inc., Credit Suisse Securities (USA) LLC, Deutsche Bank Securities Inc., DNB Markets, Inc., Jefferies LLC, J.P. Morgan Securities LLC, Mizuho Securities USA Inc., Morgan Stanley & Co. LLC, MUFG Securities Americas Inc., Raymond James & Associates, Inc., RBC Capital Markets, LLC, Scotia Capital (USA) Inc., SG Americas Securities, LLC, SMBC Nikko Securities America, Inc., SunTrust Robinson Humphrey, Inc., TD Securities (USA) LLC, UBS Securities LLC, USCA Securities LLC and Wells Fargo Securities, LLC (incorporated by reference to Exhibit 1.1 to Form 8-K filed on August 4, 2016).
10.2	Second Amendment to 364-Day Revolving Credit Agreement dated as of September 14, 2016, by and among Enterprise Products Operating LLC, Citibank, N.A., as Administrative Agent, the Lenders party thereto, Wells Fargo Bank, National Association, DNB Bank ASA, New York Branch, JPMorgan Chase Bank, N.A., Mizuho Bank, Ltd., and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Co-Syndication Agents, and Royal Bank of Canada, The Bank of Nova Scotia, SunTrust Bank and UBS Securities LLC, as Co-Documentation Agents, and Citigroup Global Markets Inc., Wells Fargo Securities, LLC, DNB Markets, Inc., J.P. Morgan Securities LLC, Mizuho Bank, Ltd., The Bank of Tokyo-Mitsubishi UFJ, Ltd., RBC Capital Markets, The Bank of Nova Scotia, SunTrust Robinson Humphrey, Inc. and UBS Securities LLC, as Joint Lead Arrangers and Joint Book Runners (incorporated by reference to Exhibit 10.1 to Form 8-K filed on September 14, 2016).
12.1#	Computation of ratio of earnings to fixed charges for the nine months ended September 30, 2016 and each of the years ended December 31, 2015, 2014, 2013, 2012 and 2011.
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 nine months ended September 30, 2016.
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 nine months ended September 30, 2016.
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 nine months ended September 30, 2016.
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 nine months ended September 30, 2016.
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 nine months ended September 30, 2016.
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 nine months ended September 30, 2016.
101.CAL#	XBRL Calculation Linkbase Document
101.DEF#	XBRL Definition Linkbase Document
101.INS#	XBRL Instance Document
101.LAB#	XBRL Labels Linkbase Document
101.PRE#	XBRL Presentation Linkbase Document

101.SCH#	XBRL Schema Document

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

\# Filed with this report.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on November 4, 2016.

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

By: Enterprise Products Holdings LLC, as General Partner

Date: November 4, 2016

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