

ENTERPRISE PRODUCTS PARTNERS L P

Form 10-Q

November 06, 2015

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, 2015

OR

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

For the transition period from ____ to ____.

Commission file number: 1-14323

ENTERPRISE PRODUCTS PARTNERS L.P.

(Exact Name of Registrant as Specified in Its Charter)

Delaware

76-0568219

(State or Other Jurisdiction of
Incorporation or Organization)

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

1100 Louisiana Street, 10th Floor

Houston, Texas 77002

(Address of Principal Executive Offices, including Zip Code)

(713) 381-6500

(Registrant's Telephone Number, including Area Code)

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

Yes No

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

Yes No

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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 2,005,753,801 common units of Enterprise Products Partners L.P. outstanding at the close of business on October 30, 2015. Our common units trade on the New York Stock Exchange under the ticker symbol “EPD.”

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

Item 1. Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.

UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEETS

(Dollars in millions)

	September 30, 2015	December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	\$80.5	\$74.4
Restricted cash	46.2	--
Accounts receivable – trade, net of allowance for doubtful accounts of \$12.9 at September 30, 2015 and \$13.9 at December 31, 2014	2,802.0	3,823.0
Accounts receivable – related parties	1.7	2.8
Inventories	1,085.4	1,014.2
Derivative assets	241.8	226.0
Prepaid and other current assets	402.4	350.3
Total current assets	4,660.0	5,490.7
Property, plant and equipment, net	31,214.1	29,881.6
Investments in unconsolidated affiliates	2,625.3	3,042.0
Intangible assets, net of accumulated amortization of \$1,192.2 at September 30, 2015 and \$1,246.3 at December 31, 2014 (see Note 9)	4,082.1	4,302.1
Goodwill (see Note 9)	5,749.2	4,300.2
Other assets	197.1	184.4
Total assets	\$48,527.8	\$47,201.0
LIABILITIES AND EQUITY		
Current liabilities:		
Current maturities of debt (see Note 10)	\$1,619.4	\$2,206.4
Accounts payable – trade	844.9	773.8
Accounts payable – related parties	80.3	118.9
Accrued product payables	2,547.9	3,853.3
Accrued liability related to EFS Midstream acquisition (see Note 8)	997.7	--
Accrued interest	198.9	335.5
Other current liabilities	589.8	585.8
Total current liabilities	6,878.9	7,873.7
Long-term debt (see Note 10)	20,840.7	19,157.4
Deferred tax liabilities	53.4	66.6
Other long-term liabilities	401.9	411.1
Commitments and contingencies (see Note 15)		
Equity:		
Partners' equity:		
Limited partners:		
Common units (2,005,785,601 units outstanding at September 30, 2015 and 1,937,324,817 units outstanding at December 31, 2014)	20,392.8	18,304.8
Accumulated other comprehensive loss	(230.7)	(241.6)

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Total partners' equity	20,162.1	18,063.2
Noncontrolling interests	190.8	1,629.0
Total equity	20,352.9	19,692.2
Total liabilities and equity	\$48,527.8	\$47,201.0

See Notes to Unaudited Condensed Consolidated Financial Statements.

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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,	
	2015	2014	2015	2014
Revenues:				
Third parties	\$6,294.0	\$12,319.2	\$20,845.6	\$37,697.1
Related parties	13.9	11.0	27.3	63.8
Total revenues (see Note 12)	6,307.9	12,330.2	20,872.9	37,760.9
Costs and expenses:				
Operating costs and expenses:				
Third parties	5,167.9	11,198.1	17,642.6	34,198.9
Related parties	284.7	216.7	783.9	735.5
Total operating costs and expenses	5,452.6	11,414.8	18,426.5	34,934.4
General and administrative costs:				
Third parties	20.8	18.1	57.9	60.0
Related parties	28.2	31.9	85.3	90.9
Total general and administrative costs	49.0	50.0	143.2	150.9
Total costs and expenses (see Note 12)	5,501.6	11,464.8	18,569.7	35,085.3
Equity in income of unconsolidated affiliates	103.1	72.3	302.5	179.1
Operating income	909.4	937.7	2,605.7	2,854.7
Other income (expense):				
Interest expense	(243.7)	(229.8)	(723.2)	(679.6)
Change in fair value of Liquidity Option Agreement (see Note 15)	(4.3)	--	(15.8)	--
Other, net	1.8	(1.0)	2.6	(0.2)
Total other expense, net	(246.2)	(230.8)	(736.4)	(679.8)
Income before income taxes	663.2	706.9	1,869.3	2,174.9
Provision for income taxes	(5.5)	(7.7)	(4.4)	(22.5)
Net income	657.7	699.2	1,864.9	2,152.4
Net income attributable to noncontrolling interests (see Note 11)	(8.4)	(8.1)	(28.5)	(24.8)
Net income attributable to limited partners	\$649.3	\$691.1	\$1,836.4	\$2,127.6
Earnings per unit: (see Note 14)				
Basic earnings per unit	\$0.33	\$0.38	\$0.94	\$1.16
Diluted earnings per unit	\$0.32	\$0.37	\$0.92	\$1.13

See Notes to Unaudited Condensed Consolidated Financial Statements.

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

	For the Three Months Ended September 30, 2015 2014		For the Nine Months Ended September 30, 2015 2014	
Net income	\$657.7	\$699.2	\$1,864.9	\$2,152.4
Other comprehensive income (loss):				
Cash flow hedges:				
Commodity derivative instruments:				
Changes in fair value of cash flow hedges	85.8	58.1	112.3	16.1
Reclassification of losses (gains) to net income	(46.8)	(18.0)	(128.1)	12.9
Interest rate derivative instruments:				
Reclassification of losses to net income	8.9	8.0	26.3	23.9
Total cash flow hedges	47.9	48.1	10.5	52.9
Other	--	--	0.4	--
Total other comprehensive income	47.9	48.1	10.9	52.9
Comprehensive income	705.6	747.3	1,875.8	2,205.3
Comprehensive income attributable to noncontrolling interests	(8.4)	(8.1)	(28.5)	(24.8)
Comprehensive income attributable to limited partners	\$697.2	\$739.2	\$1,847.3	\$2,180.5

See Notes to Unaudited Condensed Consolidated Financial Statements.

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ENTERPRISE PRODUCTS PARTNERS L.P.

UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED CASH FLOWS

(Dollars in millions)

	For the Nine Months Ended September 30,	
	2015	2014
Operating activities:		
Net income	\$1,864.9	\$2,152.4
Reconciliation of net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	1,147.7	992.4
Non-cash asset impairment charges (see Note 4)	139.1	18.2
Equity in income of unconsolidated affiliates	(302.5)	(179.1)
Distributions received from unconsolidated affiliates	362.4	260.7
Net losses (gains) attributable to asset sales and insurance recoveries (see Note 16)	14.7	(99.0)
Gains on early extinguishment of debt	(1.4)	--
Deferred income tax expense (benefit)	(13.3)	2.6
Changes in fair value of Liquidity Option Agreement	15.8	--
Changes in fair market value of derivative instruments	(7.7)	(3.8)
Net effect of changes in operating accounts (see Note 16)	(627.9)	(435.8)
Other operating activities	(0.6)	(4.2)
Net cash flows provided by operating activities	2,591.2	2,704.4
Investing activities:		
Capital expenditures	(2,630.5)	(1,879.5)
Contributions in aid of construction costs	11.4	20.0
Decrease (increase) in restricted cash	(46.2)	59.0
Cash used for business combinations, net of cash received (see Note 8)	(1,045.1)	--
Investments in unconsolidated affiliates	(130.7)	(583.3)
Proceeds from asset sales and insurance recoveries (see Note 16)	1,537.3	121.5
Other investing activities	(4.4)	(5.8)
Cash used in investing activities	(2,308.2)	(2,268.1)
Financing activities:		
Borrowings under debt agreements	17,113.7	7,167.5
Repayments of debt	(16,139.2)	(4,856.3)
Debt issuance costs	(23.9)	(18.1)
Cash distributions paid to limited partners (see Note 11)	(2,185.1)	(1,948.2)
Cash payments made in connection with distribution equivalent rights	(5.6)	(2.4)
Cash distributions paid to noncontrolling interests	(33.2)	(29.4)
Cash contributions from noncontrolling interests	37.4	4.0
Net cash proceeds from the issuance of common units	1,011.4	304.9
Other financing activities	(52.4)	(53.6)
Cash provided by (used in) financing activities	(276.9)	568.4
Net change in cash and cash equivalents	6.1	1,004.7
Cash and cash equivalents, January 1	74.4	56.9
Cash and cash equivalents, September 30	\$80.5	\$1,061.6

See Notes to Unaudited Condensed Consolidated Financial Statements.

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ENTERPRISE PRODUCTS PARTNERS L.P.

UNAUDITED CONDENSED STATEMENTS OF CONSOLIDATED EQUITY

(See Note 11 for Unit History, Accumulated Other Comprehensive

Income (Loss) and Noncontrolling Interests)

(Dollars in millions)

	Partners' Equity			
		Accumulated Other Comprehensive		
	Limited Partners	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)	--
Transfer 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

	Partners' Equity			
		Accumulated Other Comprehensive		
	Limited Partners	Income (Loss)	Noncontrolling Interests	Total
Balance, December 31, 2013	\$ 15,573.8	\$ (359.0)	\$ 225.6	\$ 15,440.4
Net income	2,127.6	--	24.8	2,152.4
Cash distributions paid to limited partners	(1,948.2)	--	--	(1,948.2)
Cash payments made in connection with distribution equivalent rights	(2.4)	--	--	(2.4)
Cash distributions paid to noncontrolling interests	--	--	(29.4)	(29.4)
Cash contributions from noncontrolling interests	--	--	4.0	4.0
Net cash proceeds from the issuance of common units	304.9	--	--	304.9
Amortization of fair value of equity-based awards	61.6	--	--	61.6
Cash flow hedges	--	52.9	--	52.9
Other	(53.7)	--	(0.6)	(54.3)
Balance, September 30, 2014	\$ 16,063.6	\$ (306.1)	\$ 224.4	\$ 15,981.9

See Notes to Unaudited Condensed Consolidated Financial Statements.

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ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

KEY REFERENCES USED IN THESE

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

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

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

In addition to owning our general partner, EPCO and its privately held affiliates owned approximately 33.7% of our limited partner interests at September 30, 2015.

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

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

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

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”). See Note 8 for additional information regarding this acquisition.

Note 1. Partnership Operations, Organization and Basis of Presentation

General

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

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ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 and in the Gulf of Mexico. Our assets currently include approximately 49,000 miles of pipelines; 225 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.

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

On July 24, 2015, we completed the sale of our Offshore Business to Genesis. As a result of this sale, we renamed our Onshore Crude Oil Pipelines & Services business segment “Crude Oil Pipelines & Services.” In addition, we renamed our Onshore Natural Gas Pipelines & Services business segment “Natural Gas Pipelines & Services.” The operations reported within these two onshore segments did not change due to these name changes. Our consolidated financial statements reflect ownership of the Offshore Business through July 24, 2015. See Note 12 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. See Note 8 for information regarding this acquisition.

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.

Note 2. General Accounting and Disclosure Matters

Our results of operations for the three and nine months ended September 30, 2015 are not necessarily indicative of results expected for the full year of 2015. In our opinion, the accompanying Unaudited Condensed Consolidated Financial Statements include all adjustments consisting of normal recurring accruals necessary for fair presentation. Although we believe the disclosures in these financial statements are adequate and make the information presented not misleading, certain information and footnote disclosures normally included in annual financial statements prepared in accordance with U.S. generally accepted accounting principles (“GAAP”) have been condensed or omitted pursuant to the rules and regulations of the U.S. Securities and Exchange Commission (“SEC”).

These Unaudited Condensed Consolidated Financial Statements and Notes thereto should be read in conjunction with the Audited Consolidated Financial Statements and Notes thereto included in our annual report on Form 10-K for the year ended December 31, 2014 (the “2014 Form 10-K”) filed with the SEC on March 2, 2015.

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ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 15 for additional information regarding our contingencies.

Derivative Instruments

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

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

Estimates

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

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

Income Taxes

Provision for income taxes primarily reflects our state tax obligations under the Revised Texas Franchise Tax (the “Texas Margin Tax”).

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NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Restricted Cash

Restricted cash represents amounts held in segregated bank accounts by our clearing brokers as margin in support of our commodity derivative instruments portfolio and related physical purchases and sales of natural gas, NGLs, crude oil and refined products. Additional cash may be restricted to maintain our commodity derivative instruments portfolio as prices fluctuate or deposit requirements change. At September 30, 2015, our restricted cash amounts were \$46.2 million. We did not have any restricted cash as of December 31, 2014. See Note 4 for information regarding our derivative instruments and hedging activities.

Note 3. Equity-based Awards

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2015	2014	2015	2014
Equity-classified awards:				
Restricted common unit awards	\$3.1	\$8.7	\$13.1	\$29.3
Phantom unit awards	20.3	12.9	60.2	32.3
Liability-classified awards	--	0.1	0.2	0.4
Total	\$23.4	\$21.7	\$73.5	\$62.0

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, 2015, EPCO's significant long-term incentive plans applicable to us were the Enterprise Products 1998 Long-Term Incentive Plan ("1998 Plan") and the 2008 Enterprise Products Long-Term Incentive Plan (Third Amendment and Restatement) ("2008 Plan"). Up to 14,000,000 of our common units may be issued as awards under the 1998 Plan. The maximum number of common units available for issuance under the 2008 Plan was 30,000,000 at September 30, 2015. This amount will automatically increase under the terms of the 2008 Plan by 5,000,000 common units on January 1, 2016 and will continue to automatically increase annually on January 1 thereafter during the term of the 2008 Plan; provided, however, that in no event shall the maximum aggregate number exceed 70,000,000 common units. After giving effect to awards granted under the 1998 Plan and 2008 Plan through September 30, 2015, a total of 3,040,506 and 16,277,823 additional common units were available for issuance under these plans, respectively.

Restricted Common Unit Awards

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

date and are non-vested until the required service periods expire. Restricted common units are included in the number of common units outstanding as presented on our Unaudited Condensed Consolidated Balance Sheets.

The fair value of a restricted common unit award is based on the market price per unit of our common units on the date of grant. Compensation expense is recognized based on the grant date fair value, net of an allowance for estimated forfeitures, over the requisite service or vesting period.

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

	Number of Units	Weighted- Average Grant Date Fair Value per Unit (1)
Restricted common units at December 31, 2014	4,229,790	\$ 26.96
Vested	(1,997,194)	\$ 25.99
Forfeited	(157,750)	\$ 27.64
Restricted common units at September 30, 2015	2,074,846	\$ 27.85

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

Each recipient of a restricted common unit award is entitled to nonforfeitable cash distributions equal to the product of the number of restricted common units outstanding for the participant and the cash distribution per unit paid to our common unitholders. These distributions are included in “Cash distributions paid to limited partners” as presented on our Unaudited Condensed Statements of Consolidated Cash Flows.

The following table presents supplemental information regarding our restricted common unit awards for the periods indicated:

	For the Three Months Ended September 30, 2015		For the Nine Months Ended September 30, 2014	
Cash distributions paid to restricted common unitholders	\$0.8	\$1.6	\$3.2	\$5.7
Total intrinsic value of restricted common unit awards that vested during period	1.5	1.3	66.9	85.4

For the EPCO group of companies, the unrecognized compensation cost associated with restricted common unit awards was an aggregate \$11.5 million at September 30, 2015, of which our share of the cost is currently estimated to be \$9.6 million. Due to the graded vesting provisions of these awards, we expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 1.1 years.

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, 2015, substantially all of our phantom unit awards are expected to result in the issuance of common units upon vesting; therefore, the applicable awards are accounted for as equity-classified awards. The grant date fair value of a phantom unit award is based on the market price per unit of our common units on the date of grant. Compensation expense is recognized based on the grant date fair value, net of an allowance for estimated forfeitures, over the requisite service or vesting period.

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

	Number of Units	Weighted- Average Grant Date Fair Value per Unit (1)
Phantom unit awards at December 31, 2014	3,342,390	\$ 33.13
Granted (2)	3,491,040	\$ 33.97
Vested	(933,890)	\$ 33.13
Forfeited	(275,356)	\$ 33.51
Phantom unit awards at September 30, 2015	5,624,184	\$ 33.63

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

(2) The aggregate grant date fair value of phantom unit awards issued during 2015 was \$118.6 million based on a grant date market price of our common units ranging from \$27.31 to \$34.40 per unit. An estimated annual forfeiture rate of 3.5% was applied to these awards.

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

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2015	2014	2015	2014
Cash payments made in connection with DERs	\$2.2	\$1.2	\$5.6	\$2.4
Total intrinsic value of phantom unit awards that vested during period	2.3	0.1	31.0	1.3

For the EPCO group of companies, the unrecognized compensation cost associated with phantom unit awards was \$100.4 million at September 30, 2015, of which our share of the cost is currently estimated to be \$91.7 million. Due to the graded vesting provisions of these awards, we expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.0 years.

Unit Option Awards

EPCO’s long-term incentive plans provide for the issuance of non-qualified incentive options denominated in our common units. In general, unit option awards have a vesting period of four years from the date of grant and expire at the end of the calendar year following the year of vesting (e.g., an option vesting on May 29, 2014 will expire on December 31, 2015). However, unit option awards only become exercisable at certain times during the calendar year following the year in which they vest (typically the months of February, May, August and November).

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

	Number of Units (1)	Weighted- Average Strike Price (dollars/unit)	Weighted- Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (2)
Unit option awards at December 31, 2014	1,270,000	\$ 16.14		
Exercised	(1,080,000)	\$ 16.14		
Unit option awards at September 30, 2015	190,000	\$ 16.14	0.3	\$ 1.7

(1) All of the unit option awards outstanding at September 30, 2015 were exercisable. None of the unit option awards outstanding at December 31, 2014 were exercisable.

(2) Aggregate intrinsic value reflects fully vested unit option awards at the dates indicated.

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

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

	For the Three Months Ended September 30, 2015		For the Nine Months Ended September 30, 2014	
Total intrinsic value of unit option awards exercised during period	\$ 0.2	\$ --	\$ 19.8	\$ 57.5
Cash received from EPCO in connection with the exercise of unit option awards	0.2	--	11.5	33.4
Unit option award-related cash reimbursements to EPCO	0.2	--	19.8	57.5

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

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Note 4. Derivative Instruments, Hedging Activities and Fair Value Measurements

In the normal course of our business operations, we are exposed to certain risks, including changes in interest rates and commodity prices. In order to manage risks associated with assets, liabilities and certain anticipated future transactions, we use derivative instruments such as futures, forward contracts, swaps, options and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities.

Interest Rate Hedging Activities

We may utilize interest rate swaps, forward starting swaps and similar derivative instruments to manage our exposure to changes in interest rates charged on borrowings under certain consolidated debt agreements. This strategy may be used in controlling our overall cost of capital associated with such borrowings. At December 31, 2014, we did not have any interest rate hedging derivative instruments outstanding. The following table summarizes our portfolio of interest rate swaps at September 30, 2015:

	Number and Type of Derivatives	Notional Amount	Period of Hedge	Rate Swap	Accounting Treatment
Hedged Transaction	Outstanding				
Senior Notes	OO 10 fixed-to-floating swaps	\$ 750.0	5/2015 to 5/2018	1.65% to 0.79%	Fair value hedge

Interest rate swaps exchange the stated interest rate paid on a notional amount of existing debt for the fixed or floating interest rate stipulated in the derivative instrument.

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Commodity Hedging Activities

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

Derivative Purpose	Volume (1)		Accounting Treatment
	Current (2)	Long-Term (2)	
<u>Derivatives designated as hedging instruments:</u>			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction (Bcf)	4.9	n/a	Cash flow hedge
Forecasted sales of NGLs (MMBbls) (3)	1.1	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchases of NGLs (MMBbls)	0.1	n/a	Cash flow hedge
Forecasted sales of octane enhancement products (MMBbls)	0.5	n/a	Cash flow hedge
Natural gas marketing:			
Forecasted purchases of natural gas for fuel (Bcf)	6.4	n/a	Cash flow hedge
Forecasted sales of natural gas (Bcf)	0.1	n/a	Cash flow hedge
Natural gas storage inventory management activities (Bcf)	10.2	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	34.6	0.5	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	49.8	n/a	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products (MMBbls)	0.4	n/a	Cash flow hedge
Forecasted sales of refined products (MMBbls)	0.7	n/a	Cash flow hedge
Refined products inventory management activities (MMBbls)	0.2	n/a	Fair value hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	9.0	1.6	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	11.9	1.6	Cash flow hedge
<u>Derivatives not designated as hedging instruments:</u>			
Natural gas risk management activities (Bcf) (4,5)	65.9	9.6	Mark-to-market
NGL risk management activities (MMBbls) (5)	14.9	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (5)	5.8	0.4	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, April 2016 and March 2018, respectively.

(3) Forecasted sales of NGL volumes under natural gas processing exclude 0.7 MMBbls of additional hedges executed under contracts that have been designated as normal sales agreements.

(4) Current and long-term volumes include 38.7 Bcf and 0.9 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.

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

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

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

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

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

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

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

	Asset Derivatives September 30,				Liability Derivatives			
	2015		December 31, 2014		September 30, 2015		December 31, 2014	
	Balance		Balance		Balance		Balance	
	Sheet	Fair	Sheet	Fair	Sheet	Fair	Sheet	Fair
	Location	Value	Location	Value	Location	Value	Location	Value
<u>Derivatives designated as hedging instruments</u>								
	Current		Current		Other		Other	
Interest rate derivatives	assets	\$7.4	assets	\$--	current	\$--	current	\$--
	Other		Other		liabilities		liabilities	
Interest rate derivatives	assets	0.2	assets	--	Other	--	Other	--
Total interest rate derivatives		7.6		--	liabilities	--	liabilities	--
	Current		Current		Other		Other	
Commodity derivatives	assets	216.9	assets	217.9	current	178.5	current	145.3
	Other		Other		liabilities		liabilities	
Commodity derivatives	assets	8.3	assets	--	Other	8.2	Other	--
Total commodity derivatives		225.2		217.9	liabilities	186.7	liabilities	145.3
Total derivatives designated as hedging instruments		\$232.8		\$217.9		\$186.7		\$145.3
<u>Derivatives not designated as hedging instruments</u>								
	Current		Current		Other		Other	
Commodity derivatives	assets	\$17.5	assets	\$8.1	current	\$9.4	current	\$0.7
	Other		Other		liabilities		liabilities	
Commodity derivatives	assets	0.1	assets	0.6	Other	1.0	Other	1.4
Total commodity derivatives		\$17.6		\$8.7	liabilities	\$10.4	liabilities	\$2.1

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

Offsetting of Financial Assets and Derivative Assets						
Gross	Gross	Amounts	Gross	Amounts	Not Offset	Amounts
Amounts	Amounts	of Assets	Amounts	in the	Balance Sheet	That
of	Offset in	Presented	Financial	Cash	Cash	Would
Recognition	the	in the	Instruments	Collateral	Collateral	Have

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	Assets	Balance Sheet	Balance Sheet		Received	Paid	Been Presented On Net Basis (v) = (iii) + (iv)
	(i)	(ii)	(iii) = (i) – (ii)	(iv)			
As of September 30, 2015:							
Interest rate derivatives	\$ 7.6	\$ --	\$ 7.6	\$--	\$ --	\$ --	\$ 7.6
Commodity derivatives	242.8	--	242.8	(180.3)	(38.2)	(9.6)	14.7
As of December 31, 2014:							
Commodity derivatives	\$ 226.6	\$ --	\$ 226.6	\$(147.3)	\$ (23.9)	\$ --	\$ 55.4

Offsetting of Financial Liabilities and Derivative Liabilities

	Gross Amounts of Recognized Liabilities		Amounts of Liabilities Presented in the Balance Sheet	Gross Amounts Not Offset in the Balance Sheet		Amounts That Would Have Been Presented On Net Basis
	(i)	(ii)	(iii) = (i) – (ii)	(iv)	Cash Collateral Paid	(v) = (iii) + (iv)
As of September 30, 2015:						
Commodity derivatives	\$ 197.1	\$ --	\$ 197.1	\$(180.3)	\$ --	\$ 16.8
As of December 31, 2014:						
Commodity derivatives	\$ 147.4	\$ --	\$ 147.4	\$(147.3)	\$ --	\$ 0.1

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NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Derivative assets and liabilities recorded on our Unaudited Condensed Consolidated Balance Sheets are presented on a gross-basis and determined at the individual transaction level. The tabular presentation above provides a means for comparing the gross amount of derivative assets and liabilities, excluding associated accounts payable and receivable, to the net amount that would likely be receivable or payable under a default scenario based on the existence of rights of offset in the respective derivative agreements. Any cash collateral paid or received is reflected in these tables, but only to the extent that it represents variation margins. Any amounts associated with derivative prepayments or initial margins that are not influenced by the derivative asset or liability amounts or those that are determined solely on their volumetric notional amounts are excluded from these tables.

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

Derivatives in Fair Value Hedging Relationships	Location	Gain (Loss) Recognized in Income on Derivative			
		For the Three Months Ended September 30, 2015		For the Nine Months Ended September 30, 2014	
Interest rate derivatives	Interest expense	\$5.9	\$(4.1)	\$5.1	\$(9.5)
Commodity derivatives	Revenue	3.6	(0.3)	4.0	0.6
Total		\$9.5	\$(4.4)	\$9.1	\$(8.9)

Derivatives in Fair Value Hedging Relationships	Location	Gain (Loss) Recognized in Income on Hedged Item			
		For the Three Months Ended September 30, 2015		For the Nine Months Ended September 30, 2014	
Interest rate derivatives	Interest expense	\$(5.7)	\$3.9	\$(5.2)	\$9.3
Commodity derivatives	Revenue	(2.5)	1.0	7.4	(1.4)
Total		\$(8.2)	\$4.9	\$2.2	\$7.9

With respect to our derivative instruments designated as fair value hedges, amounts attributable to ineffectiveness and those excluded from the assessment of hedge effectiveness were not material to our consolidated financial statements during the periods presented.

The following tables present the effect of our derivative instruments designated as cash flow hedges on our Unaudited Condensed Statements of Consolidated Operations and Unaudited Condensed Statements of Consolidated Comprehensive Income for the periods indicated:

Derivatives in Cash Flow Hedging Relationships	Change in Value Recognized in Other Comprehensive Income (Loss) on Derivative (Effective Portion) For the Three Months Ended September 30, 2015 2014				For the Nine Months Ended September 30, 2015 2014	
Commodity derivatives – Revenue (1)	\$87.4	\$58.8	\$113.9	\$15.2		
Commodity derivatives – Operating costs and expenses (1)	(1.6)	(0.7)	(1.6)	0.9		
Total	\$85.8	\$58.1	\$112.3	\$16.1		

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

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NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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, 2015 2014			
		For the Nine Months Ended September 30, 2015 2014		For the Nine Months Ended September 30, 2015 2014	
Interest rate derivatives	Interest expense	\$(8.9)	\$(8.0)	\$(26.3)	\$(23.9)
Commodity derivatives	Revenue	46.8	17.8	128.6	(14.5)
Commodity derivatives	Operating costs and expenses	--	0.2	(0.5)	1.6
Total		\$37.9	\$10.0	\$101.8	\$(36.8)

Derivatives in Cash Flow Hedging Relationships	Location	Gain (Loss) Recognized in Income on Derivative (Ineffective Portion) For the Three Months Ended September 30, 2015 2014			
		For the Nine Months Ended September 30, 2015 2014		For the Nine Months Ended September 30, 2015 2014	
Commodity derivatives	Revenue	\$(3.5)	\$0.1	\$(3.1)	\$ --
Commodity derivatives	Operating costs and expenses	--	(0.1)	--	--
Total		\$(3.5)	\$--	\$(3.1)	\$ --

Over the next twelve months, we expect to reclassify \$36.8 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 \$54.1 million of net gains attributable to commodity derivative instruments from accumulated other comprehensive income to earnings, \$55.7 million as an increase in revenue and \$1.6 million as an increase in operating costs and expenses.

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

Derivatives Not Designated as Hedging Instruments	Location	Gain (Loss) Recognized in Income on Derivative For the Three Months Ended September 30, 2015 2014			
		For the Nine Months Ended September 30, 2015 2014		For the Nine Months Ended September 30, 2015 2014	

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		2015	2014	2015	2014
Interest rate derivatives	Interest expense	\$--	\$--	\$--	\$(0.1)
Commodity derivatives	Revenue	--	0.8	3.9	(26.8)
Commodity derivatives	Operating costs and expenses	(0.3)	--	--	--
Total		\$(0.3)	\$0.8	\$3.9	\$(26.9)

Fair Value Measurements

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

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

Financial liabilities:

Liquidity Option Agreement	\$--	\$ --	\$ 219.7	\$219.7
Commodity derivatives	13.8	133.0	0.6	147.4
Total	\$13.8	\$ 133.0	\$ 220.3	\$367.1

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

		For the Nine Months Ended September 30, 2015 2014	
Financial asset (liability) balance, net, January 1	Location		
Total gains (losses) included in:			
Net income (1)	Revenue	(0.4)	4.6
	Commodity derivative instruments – changes in fair value		
Other comprehensive income	of cash flow hedges	(1.5)	--
Settlements	Revenue	(0.5)	(0.1)
Transfers out of Level 3		0.1	--
Financial asset (liability) balance, net, March 31		(221.6)	7.7
Total gains (losses) included in:			
Net income (1)	Revenue	(0.4)	(3.3)
Net income	Other expense, net	(11.5)	--
	Commodity derivative instruments – changes in fair value		
Other comprehensive income	of cash flow hedges	(1.0)	--
Settlements	Revenue	0.2	(1.8)
Transfers out of Level 3		1.5	--
Financial asset (liability) balance, net, June 30		(232.8)	2.6
Total gains (losses) included in:			
Net income (1)	Revenue	(0.3)	(0.9)
Net income	Other expense, net	(4.3)	--
	Commodity derivative instruments – changes in fair value		
Other comprehensive income	of cash flow hedges	(15.5)	(2.5)
Settlements	Revenue	0.3	0.1
Transfers out of Level 3		1.1	--
Financial asset (liability) balance, net, September 30		\$(251.5)	\$(0.7)

(1) There were \$1.1 million of unrealized losses included in these amounts for the nine months ended September 30, 2015. There were unrealized gains of \$0.8 million and \$1.3 million included in these amounts for the three and nine months ended September 30, 2014, respectively.

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

Fair Value			
Financial	Financial Valuation	Unobservable	
Assets	Liabilities Techniques	Input	Range

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Commodity derivatives – Crude oil	\$0.7	\$ 1.3	Discounted cash flow	Forward commodity prices	\$44.47-\$50.74/barrel
Commodity derivatives – Natural gasoline	0.3	15.6	Discounted cash flow	Forward commodity prices	\$0.93-\$1.00/gallon
Commodity derivatives – Propane	--	0.1	Discounted cash flow	Forward commodity prices	\$0.50/gallon
Total	\$1.0	\$ 17.0			

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, 2015. In general, changes in the price of the underlying commodity increases or decreases the fair value of a commodity derivative depending on whether the derivative was purchased or sold. We generally expect changes in the fair value of our derivative instruments to be offset by corresponding changes in the fair value of our hedged exposures.

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

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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,	
	2015	2014	2015	2014
NGL Pipelines & Services	\$ 14.6	\$ 1.2	\$ 20.6	\$ 6.6
Crude Oil Pipelines & Services	--	0.4	25.9	2.2
Natural Gas Pipelines & Services	--	0.4	21.5	0.7
Petrochemical & Refined Products Services	12.2	3.7	12.6	8.7
Offshore Pipelines & Services	--	--	58.5	--
Total	\$ 26.8	\$ 5.7	\$ 139.1	\$ 18.2

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

Our non-cash asset impairment charges for the 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. Our non-cash asset impairment charges for the nine months ended September 30, 2015 primarily reflect the \$54.8 million charge we recorded in connection with the sale of our Offshore Business (see Note 6) and the abandonment of certain natural gas and crude oil pipeline assets in Texas. Our non-cash asset impairment charges for the nine months ended September 30, 2014 primarily reflect the abandonment of assets classified as property, plant and equipment.

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:

Carrying Value at September 30, 2015	Fair Value Measurements at the End of the Reporting Period Using			Total Non-Cash Impairment Loss
	Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	

		(Level 1)			
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 second quarter of 2015 upon reclassification of our Offshore Business to held for sale status.

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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, 2014:

		Fair Value Measurements at the End of the Reporting Period Using Quoted Prices in Active Markets			
	Carrying Value at September 30, 2014	Identifiable Assets (Level 1)	Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Non-Cash Impairment Loss
Long-lived assets disposed of other than by sale	\$ --	\$--	\$ --	\$ --	\$ 11.7
Long-lived assets held for sale	1.1	--	--	1.1	6.5
Total					\$ 18.2

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 \$20.77 billion and \$22.16 billion at September 30, 2015 and December 31, 2014, respectively. The aggregate carrying value of these debt obligations was \$20.88 billion and \$20.48 billion at September 30, 2015 and December 31, 2014, respectively. These values are based on quoted market prices for such debt or debt of similar terms and maturities (Level 2), our credit standing and the credit standing of our counterparties. Changes in market rates of interest affect the fair value of our fixed-rate debt. The amounts reported for fixed-rate debt obligations as of September 30, 2015, exclude those amounts hedged using fixed-to-floating interest rate swaps. See "Interest Rate Hedging Activities" within this Note 4 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 5. Inventories

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

	September 30, 2015	December 31, 2014
NGLs	\$ 740.5	\$ 579.1
Petrochemicals and refined products	158.0	295.6
Crude oil	152.2	97.8
Natural gas	34.7	41.7
Total	\$ 1,085.4	\$ 1,014.2

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2015	2014	2015	2014
Cost of sales (1)	\$4,419.9	\$10,455.1	\$15,355.9	\$32,213.1
Lower of cost or market adjustments	2.1	6.7	6.1	14.6

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

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Note 6. Property, Plant and Equipment

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

	Estimated Useful Life in Years	September 30, 2015	December 31, 2014
Plants, pipelines and facilities (1)	3-45 (6)	\$31,686.3	\$30,834.9
Underground and other storage facilities (2)	5-40 (7)	2,847.7	2,584.2
Platforms and facilities (3)	20-31	--	659.7
Transportation equipment (4)	3-10	164.8	154.2
Marine vessels (5)	15-30	787.5	796.4
Land		261.3	262.6
Construction in progress		3,777.2	2,754.7
Total historical cost of property, plant and equipment		39,524.8	38,046.7
Less accumulated depreciation		8,310.7	8,165.1
Total property, plant and equipment, net		\$31,214.1	\$29,881.6

(1) Plants, pipelines and facilities include processing plants; NGL, natural gas, crude oil and petrochemical and refined products pipelines; terminal loading and unloading facilities; office furniture and equipment; buildings; laboratory and shop equipment and related assets.

(2) Underground and other storage facilities include underground product storage caverns; above ground storage tanks; water wells and related assets.

(3) Platforms and facilities included offshore platforms and related facilities and other associated assets located in the Gulf of Mexico prior to the sale of our Offshore Business (see below).

(4) Transportation equipment includes tractor-trailer tank trucks and other vehicles and similar assets used in our operations.

(5) Marine vessels include tow boats, barges and related equipment used in our marine transportation business.

(6) In general, the estimated useful lives of major assets within this category are: processing plants, 20-35 years; pipelines and related equipment, 5-45 years; terminal facilities, 10-35 years; office furniture and equipment, 3-20 years; buildings, 20-40 years; and laboratory and shop equipment, 5-35 years.

(7) In general, the estimated useful lives of assets within this category are: underground storage facilities, 5-35 years; storage tanks, 10-40 years; and water wells, 5-35 years.

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

For the Three Months Ended September 30, 2015	For the Nine Months Ended September 30, 2015
2014	2014

Depreciation expense (1)	\$286.2	\$283.2	\$870.1	\$822.1
Capitalized interest (2)	40.3	17.2	105.6	53.4

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

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

Sale of Offshore Business

On July 24, 2015, we consummated a sale to Genesis of our Offshore Business, which primarily consisted of our Offshore Pipelines & Services business segment, for approximately \$1.53 billion in cash. Our Offshore Business served drilling and development regions, including deepwater production fields, in the northern Gulf of Mexico offshore Texas, Louisiana, Mississippi and Alabama. As of December 31, 2014, our Offshore Business included approximately 2,350 miles of offshore natural gas and crude oil pipelines and six offshore hub platforms. Our results of operations reflect ownership of the Offshore Business through July 24, 2015.

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We viewed our Offshore Business as an extension of our midstream energy services network. As such, the sale of these assets did not represent a strategic shift in our consolidated operations, and their sale does not have a major effect on our financial results. At December 31, 2014 and June 30, 2015, segment assets for our Offshore Pipelines & Services segment represented 4.3% and 4.1%, respectively, of consolidated total segment assets. Likewise, gross operating margin from this business segment represented only 3.1% and 3.4% of our consolidated total gross operating margin for the year ended December 31, 2014 and six months ended June 30, 2015, respectively. The sale of this non-strategic business allowed us to redeploy capital to other business opportunities that we believe will generate a higher rate of return for us in the future (e.g., our recent acquisition of EFS Midstream (see Note 8)). Also, proceeds from the closing of this sale will reduce our need to issue additional equity and debt to support our ongoing capital spending program.

We recorded a non-cash asset impairment charge at June 30, 2015 of approximately \$54.8 million, which reflects the excess of the carrying value of net assets of the Offshore Business at June 30, 2015 over their comparable estimated fair value based on the transaction price. The carrying value of the net assets of the Offshore Business at June 30, 2015 totaled approximately \$1.59 billion, which included current assets of \$26.9 million, property plant and equipment of \$1.14 billion, investments in unconsolidated affiliates of \$482.4 million, intangible assets of \$37.1 million and goodwill of \$82.0 million. Total liabilities were \$116.4 million and noncontrolling interests were \$62.2 million at that date. The fair value of the Offshore Business based on the transaction price was approximately \$1.53 billion.

Upon closing of the transaction, we recorded a loss on the sale of \$12.6 million based on the difference between the proceeds received and the carrying value of the net assets at July 24, 2015.

Operating costs and expenses for the nine months ended September 30, 2015 include \$40.1 million of depreciation expense associated with the Offshore Business. Likewise, for the three and nine months ended September 30, 2014, we recognized \$21.5 million and \$62.3 million, respectively, of depreciation expense associated with these assets.

Asset Retirement Obligations

We record asset retirement obligations (“AROs”) in connection with legal requirements to perform specified retirement activities under contractual arrangements and/or governmental regulations. Our contractual AROs primarily result from right-of-way agreements associated with our pipeline operations and real estate leases associated with our plant sites. In addition, we record AROs in connection with governmental regulations associated with the abandonment or retirement of 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, 2015 and December 31, 2014 includes \$17.8 million and \$31.3 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset.

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

ARO liability balance, December 31, 2014	\$98.3
Liabilities incurred	2.7
Liabilities settled	(5.9)
Revisions in estimated cash flows	49.0
Accretion expense	4.2
ARO related to Offshore Business sold in July 2015	(91.1)

ARO liability balance, September 30, 2015

\$57.2

Revisions to estimated cash flows include a \$39.5 million adjustment made in the second quarter of 2015 related to the Matagorda Gathering System, which was a component of the Offshore Business. In June 2015, we were notified by the U.S. Army Corps of Engineers (the "CoE") to fully remove two pipeline segments included in this system that we had originally requested to abandon in-place. As a result, we adjusted the ARO liabilities for those pipeline segments under CoE jurisdiction to account for the estimated cost of removal. All ARO liabilities related to our Offshore Business (including those of the Matagorda Gathering System) were removed from our Unaudited Condensed Consolidated Balance Sheet upon the sale of the Offshore Business on July 24, 2015.

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

Note 7. Investments in Unconsolidated Affiliates

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

	Ownership Interest at September 30, 2015	September 30, 2015	December 31, 2014
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C.	13.1%	\$ 26.4	\$ 27.7
K/D/S Promix, L.L.C.	50%	42.8	38.5
Baton Rouge Fractionators LLC	32.2%	18.4	18.8
Skelly-Belvieu Pipeline Company, L.L.C.	50%	40.3	40.1
Texas Express Pipeline LLC	35%	343.4	349.3
Texas Express Gathering LLC	45%	37.2	37.9
Front Range Pipeline LLC	33.3%	171.7	170.0
Delaware Basin Gas Processing LLC (1)	50%	28.7	--
Crude Oil Pipelines & Services:			
Seaway Crude Pipeline Company LLC	50%	1,403.1	1,431.2
Eagle Ford Pipeline LLC	50%	391.4	336.5
Eagle Ford Terminals Corpus Christi LLC (2)	50%	23.4	--
Natural Gas Pipelines & Services:			
White River Hub, LLC	50%	23.1	23.2
Petrochemical & Refined Products Services:			
Baton Rouge Propylene Concentrator, LLC	30%	5.8	6.5
Centennial Pipeline LLC ("Centennial")	50%	67.2	66.1
Other	Various	2.4	2.5
Offshore Pipelines & Services: (3)			
Poseidon Oil Pipeline Company, L.L.C.	--	--	31.8
Cameron Highway Oil Pipeline Company	--	--	201.3
Deepwater Gateway, L.L.C.	--	--	79.6
Neptune Pipeline Company, L.L.C.	--	--	34.9
Southeast Keathley Canyon Pipeline Company L.L.C.	--	--	146.1
Total investments in unconsolidated affiliates		\$ 2,625.3	\$ 3,042.0

(1) New joint venture formed with Oxy Delaware Basin Plant, LLC, a subsidiary of Occidental Petroleum Corporation, in April 2015 that will plan, design and construct a new cryogenic natural gas processing plant to accommodate the growing production of NGL-rich natural gas in the Delaware Basin.

(2) New joint venture formed with Plains Marketing, L.P., a subsidiary of Plains All American Pipeline, L.P., in March 2015 to construct and operate a marine terminal that will

handle crude oil delivered by Eagle Ford Pipeline LLC.

(3) Our investments in unconsolidated affiliates classified within the Offshore Pipelines & Services segment were sold to Genesis on July 24, 2015 (see Note 6). At June 30, 2015, the carrying value of these investments was \$482.4 million.

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, 2015		For the Nine Months Ended September 30, 2015	
	2015	2014	2015	2014
NGL Pipelines & Services	\$18.9	\$11.7	\$43.0	\$19.2
Crude Oil Pipelines & Services	81.2	46.8	220.5	131.7
Natural Gas Pipelines & Services	0.9	0.9	2.8	2.7
Petrochemical & Refined Products Services	(3.3)	(4.2)	(10.4)	(10.3)
Offshore Pipelines & Services	5.4	17.1	46.6	35.8
Total	\$103.1	\$72.3	\$302.5	\$179.1

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

	September 30, 2015	December 31, 2014
NGL Pipelines & Services	\$ 25.6	\$ 26.5
Crude Oil Pipelines & Services	20.9	21.7
Petrochemical & Refined Products Services	2.4	2.4
Offshore Pipelines & Services (1)	--	9.0
Total	\$ 48.9	\$ 59.6

(1) Our investments in unconsolidated affiliates classified within the Offshore Pipelines & Services segment were sold to Genesis in July 2015.

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

	For the Three Months Ended September 30, 2015		For the Nine Months Ended September 30, 2014	
NGL Pipelines & Services	\$0.3	\$0.2	\$0.9	\$0.9
Crude Oil Pipelines & Services	0.3	0.2	0.8	0.5
Petrochemical & Refined Products Services	--	--	--	0.1
Offshore Pipelines & Services	--	0.3	2.8	0.8
Total	\$0.6	\$0.7	\$4.5	\$2.3

Other

Centennial's credit agreement restricts its ability to pay cash dividends if a default or event of default (as defined in the credit agreement) has occurred and is continuing at the time such payments are scheduled to be paid. This business was in compliance with the terms of its credit agreement at September 30, 2015.

Note 8. Business Acquisition

Acquisition of Eagle Ford Midstream Assets

In June 2015, we announced the execution of definitive agreements to purchase all of the member interests in EFS Midstream from affiliates of Pioneer and Reliance for approximately \$2.1 billion. The purchase price will be paid in two installments. The first installment of approximately \$1.1 billion was paid at closing on July 8, 2015 and the final installment of \$1.0 billion will be paid no later than the first anniversary of the closing date. The effective date of the acquisition was July 1, 2015. We funded the cash consideration for the first installment using proceeds from the issuance of short-term notes under our commercial paper program and cash on hand.

EFS Midstream provides natural gas gathering, treating and compression and condensate gathering and processing services in the Eagle Ford Shale. The EFS Midstream system includes approximately 460 miles of natural gas and condensate gathering pipelines, ten central gathering plants, 780 million cubic feet per day (“MMcf/d”) of natural gas treating capacity and 119 thousand barrels per day (“MBPD”) of condensate stabilization capacity. Under terms of the associated agreements, Pioneer and Reliance have dedicated certain of their Eagle Ford Shale acreage to us under 20-year, fixed-fee gathering agreements that include minimum volume requirement for the first seven years. Pioneer and Reliance have also entered into related 20-year fee-based agreements with us for natural gas transportation and processing, NGL transportation and fractionation, and for processed condensate and crude oil transportation services.

We account for business acquisitions by applying the acquisition method of accounting. The acquisition method of accounting requires, among other things, that the assets acquired and liabilities assumed in a business combination be measured at their fair values as of the effective date of the acquisition. We engaged an independent third party business valuation expert to assist us in estimating the fair values of the tangible and intangible assets of EFS Midstream.

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The following table summarizes the consideration paid in the EFS Midstream acquisition and the amounts of the assets acquired and liabilities assumed as of July 1, 2015:

Consideration:	
Cash	\$1,058.5
Accrued liability related to EFS Midstream acquisition	997.7
Total consideration	\$2,056.2
Identifiable assets acquired in business combination:	
Current assets, including cash of \$13.4 million	\$64.0
Property, plant and equipment	636.0
Customer relationship intangible assets	1,409.8
Total assets acquired	2,109.8
Liabilities assumed in business combination:	
Current liabilities	(9.6)
Long-term debt	(125.0)
Other long-term liabilities	(1.3)
Total liabilities assumed	(135.9)
Total assets acquired less liabilities assumed	1,973.9
Total consideration given for EFS Midstream	2,056.2
Goodwill	\$82.3

The estimated fair value of the acquired property, plant and equipment was determined using the cost approach. Of the \$636 million of fair value assigned to property, plant and equipment, \$366 million was assigned to pipelines and rights of way, \$112 million to processing equipment, \$84 million to electrical and metering equipment, \$42 million to pumps and compressors and \$32 million to other assets.

The estimated fair value of the acquired customer relationship intangible assets was determined using an income approach, specifically a discounted cash flow analysis. Of the total assets acquired, \$1.41 billion, or 67%, was assigned to customer relationship intangible assets. In the context of EFS Midstream, a customer relationship intangible asset is broadly defined as a relationship between an asset network and the underlying production fields and producers (e.g., Pioneer and Reliance) supported by that network. The customer relationships we acquired in this transaction provide us with long-term access to the natural gas, NGL and condensate resources supported by the EFS Midstream assets.

Infrastructure such as that owned by EFS Midstream requires a significant investment, both in terms of initial construction costs and ongoing maintenance, and is generally supported by long-term contracts with producers that establish a customer base. The level of expenditures involved in constructing such asset networks can create significant economic barriers to entry that effectively limit competition (i.e., akin to a franchise). The long-term nature of the underlying producer contracts and limited risk of competition ensure a long commercial relationship with existing producers.

The discounted cash flow analysis used to estimate the fair value of the EFS Midstream customer relationships relied on Level 3 fair value inputs. Level 3 fair values are based on unobservable inputs. Unobservable inputs are used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset at the measurement date. With respect to the EFS Midstream customer relationships, the Level 3 inputs include long-range cash flow forecasts that extend for the estimated economic life of

the hydrocarbon resource base served by the asset network, anticipated contract renewals and resource base depletion rates. A discount rate of 15% was applied to the resulting cash flows.

We recorded \$82.3 million of goodwill in connection with this transaction. In general, we attribute this goodwill to our ability to leverage the acquired business with our existing asset base to create future business opportunities.

In connection with the agreements to acquire EFS Midstream, we are obligated to spend up to an aggregate of \$270 million on specified midstream gathering assets for Pioneer and Reliance, if requested by these producers, over a ten year period. If constructed, these new assets would be owned by us and be a component of the EFS Midstream asset network.

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Our consolidated revenues and net income included \$56.7 million and \$23.8 million, respectively, from EFS Midstream for the three months ended September 30, 2015.

Since the effective date of the EFS Midstream acquisition was July 1, 2015, our Unaudited Condensed Statements of Consolidated Operations do not include earnings from this business prior to this date. The following table presents selected unaudited pro forma earnings information for the nine months ended September 30, 2015 and 2014 as if the acquisition had been completed on January 1, 2014. This pro forma information was prepared using historical financial data for EFS Midstream and reflects certain estimates and assumptions made by our management. Our unaudited pro forma financial information is not necessarily indicative of what our consolidated financial results would have been for the periods presented had we acquired EFS Midstream on January 1, 2014.

	For the Three Months Ended September 30, 2014	For the Nine Months Ended September 30, 2015	2014
Pro forma earnings data:			
Revenues	\$12,388.7	\$20,993.5	\$37,927.5
Costs and expenses	11,502.6	18,645.5	35,195.2
Operating income	958.4	2,650.5	2,911.4
Net income	715.3	1,900.9	2,195.5
Net income attributable to noncontrolling interests	8.1	28.5	24.8
Net income attributable to limited partners	707.2	1,872.4	2,170.7
Basic earnings per unit:			
As reported basic earnings per unit	\$0.38	\$0.94	\$1.16
Pro forma basic earnings per unit	\$0.38	\$0.96	\$1.18
Diluted earnings per unit:			
As reported diluted earnings per unit	\$0.37	\$0.92	\$1.13
Pro forma diluted earnings per unit	\$0.38	\$0.94	\$1.15

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Note 9. Intangible Assets and Goodwill

Intangible Assets

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

	September 30, 2015			December 31, 2014		
	Gross Value	Accumulated Amortization	Carrying Value	Gross Value	Accumulated Amortization	Carrying Value
NGL Pipelines & Services:						
Customer relationship intangibles	\$550.8	\$ (183.8)) \$367.0	\$340.8	\$ (183.2)) \$157.6
Contract-based intangibles	283.0	(189.6)) 93.4	277.7	(178.7)) 99.0
IDRs (1)	--	--	--	432.6	--	432.6
Segment total	833.8	(373.4)) 460.4	1,051.1	(361.9)) 689.2
Crude Oil Pipelines & Services:						
Customer relationship intangibles	2,204.4	(28.1)) 2,176.3	1,108.0	(7.7)) 1,100.3
Contract-based intangibles	281.4	(55.4)) 226.0	281.4	(13.5)) 267.9
IDRs (1)	--	--	--	855.4	--	855.4
Segment total	2,485.8	(83.5)) 2,402.3	2,244.8	(21.2)) 2,223.6
Natural Gas Pipelines & Services:						
Customer relationship intangibles	1,246.9	(327.8)) 919.1	1,163.6	(308.9)) 854.7
Contract-based intangibles	466.0	(359.4)) 106.6	466.0	(347.8)) 118.2
Segment total	1,712.9	(687.2)) 1,025.7	1,629.6	(656.7)) 972.9
Petrochemical & Refined Products Services:						
Customer relationship intangibles	185.5	(37.3)) 148.2	198.4	(43.3)) 155.1
Contract-based intangibles	56.3	(10.8)) 45.5	56.3	(7.8)) 48.5
IDRs (1)	--	--	--	171.2	--	171.2
Segment total	241.8	(48.1)) 193.7	425.9	(51.1)) 374.8
Offshore Pipelines & Services: (2)						
Customer relationship intangibles	--	--	--	195.8	(154.9)) 40.9
Contract-based intangibles	--	--	--	1.2	(0.5)) 0.7
Segment total	--	--	--	197.0	(155.4)) 41.6
Total intangible assets	\$5,274.3	\$ (1,192.2)) 4,082.1	\$5,548.4	\$ (1,246.3)) \$4,302.1

(1) At December 31, 2014, we had indefinite-lived intangible assets outstanding with a carrying value of \$1.46 billion recorded in connection with our acquisition of the Oiltanking IDRs in October 2014. The IDRs represented contractual rights to future cash incentive distributions to be paid by Oiltanking. In February 2015 (following completion of Step 2 of the Oiltanking acquisition), the Oiltanking IDRs were cancelled and the carrying value of the IDRs were reclassified to goodwill.

(2) Our intangible assets classified within the Offshore Pipelines & Services segment were sold to Genesis in July 2015 (see Note 6).

We acquired \$1.41 billion of customer relationship intangible assets as part of the EFS Midstream acquisition (see Note 8). We assigned \$1.1 billion of these intangible assets to our Crude Oil Pipelines & Services segment, \$230.1 million to our NGL Pipelines & Services segment and \$83.3 million to our Natural Gas Pipelines & Services segment based on the nature of the services provided in connection with these relationships. These customer relationships have estimated economic lives ranging from 26 to 29 years. Amortization expense attributable to these customer

relationships is recorded using a units-of-production method that closely resembles the pattern in which the economic benefits we derive from such assets are expected to be consumed or otherwise used.

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,	
	2015	2014	2015	2014
NGL Pipelines & Services	\$9.7	\$8.1	\$24.9	\$25.4
Crude Oil Pipelines & Services	29.0	0.3	62.3	0.9
Natural Gas Pipelines & Services	10.7	11.1	30.5	34.2
Petrochemical & Refined Products Services	2.3	1.5	7.0	4.6
Offshore Pipelines & Services	--	2.5	4.5	7.6
Total	\$51.7	\$23.5	\$129.2	\$72.7

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NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

Remainder of 2015	2016	2017	2018	2019
\$ 50.3	\$218.8	\$223.5	\$220.4	\$208.6

Goodwill

Goodwill represents the excess of the purchase price of an acquired business over the amounts assigned to assets acquired and liabilities assumed in the transaction. The following table presents changes in the carrying amount of goodwill since December 31, 2014:

	NGL Pipelines & Services	Crude Oil Pipelines & Services	Natural Gas Pipelines & Services	Petrochemical & Refined Products Services	Offshore Pipelines & Services	Consolidated Total
Balance at December 31, 2014	\$2,210.2	\$918.7	\$ 296.3	\$ 793.0	\$ 82.0	\$ 4,300.2
Reclassification of Oiltanking IDR balances to goodwill in connection with the cancellation of such rights in February 2015 and other adjustments	432.6	850.7	--	170.8	--	1,454.1
Reduction in goodwill related to the sale of assets	--	--	--	--	(82.0)	(82.0)
Addition to goodwill related to the acquisition of EFS Midstream	8.9	73.4	--	--	--	82.3
Goodwill reclassified to assets held-for-sale	--	--	--	(5.4)	--	(5.4)
Balance at September 30, 2015	\$2,651.7	\$1,842.8	\$ 296.3	\$ 958.4	\$ --	\$ 5,749.2

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

During 2015, we retrospectively adjusted our provisional fair value estimate of the Liquidity Option Agreement by \$100.3 million, with a corresponding increase to goodwill, which was allocated to the appropriate business segments at December 31, 2014 as follows: \$29.8 million to NGL Pipelines & Services; \$58.8 million to Crude Oil Pipelines & Services; and \$11.7 million to Petrochemical & Refined Products Services. See Note 15 for additional information regarding this change.

In July 2015, in connection with the sale of the Offshore Business, we removed \$82.0 million of goodwill, which was allocated to these assets (see Note 6).

In July 2015, we recorded \$82.3 million of goodwill in connection with our acquisition of EFS Midstream. In general, we attribute this goodwill to our ability to leverage the acquired business with our existing asset base to create future business opportunities.

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Note 10. Debt Obligations

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

	September 30, 2015	December 31, 2014
EPO senior debt obligations:		
Commercial Paper Notes, variable-rates	\$869.5	\$906.5
Senior Notes I, 5.00% fixed-rate, due March 2015	--	250.0
Senior Notes X, 3.70% fixed-rate, due June 2015	--	400.0
Senior Notes FF, 1.25% fixed-rate, due August 2015	--	650.0
Senior Notes AA, 3.20% fixed-rate, due February 2016	750.0	750.0
364-Day Credit Agreement, variable-rate, due September 2016	--	--
Senior Notes L, 6.30% fixed-rate, due September 2017	800.0	800.0
Senior Notes V, 6.65% fixed-rate, due April 2018	349.7	349.7
Senior Notes OO, 1.65% fixed-rate, due May 2018	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 CC, 4.05% fixed-rate, due February 2022	650.0	650.0
Senior Notes HH, 3.35% fixed-rate, due March 2023	1,250.0	1,250.0
Senior Notes JJ, 3.90% fixed-rate, due February 2024	850.0	850.0
Senior Notes MM, 3.75% fixed-rate, due February 2025	1,150.0	1,150.0
Senior Notes PP, 3.70% fixed-rate, due February 2026	875.0	--
Senior Notes D, 6.875% fixed-rate, due March 2033	500.0	500.0
Senior Notes H, 6.65% fixed-rate, due October 2034	350.0	350.0
Senior Notes J, 5.75% fixed-rate, due March 2035	250.0	250.0
Senior Notes W, 7.55% fixed-rate, due April 2038	399.6	399.6
Senior Notes R, 6.125% fixed-rate, due October 2039	600.0	600.0
Senior Notes Z, 6.45% fixed-rate, due September 2040	600.0	600.0
Senior Notes BB, 5.95% fixed-rate, due February 2041	750.0	750.0
Senior Notes DD, 5.70% fixed-rate, due February 2042	600.0	600.0
Senior Notes EE, 4.85% fixed-rate, due August 2042	750.0	750.0
Senior Notes GG, 4.45% fixed-rate, due February 2043	1,100.0	1,100.0
Senior Notes II, 4.85% fixed-rate, due March 2044	1,400.0	1,400.0
Senior Notes KK, 5.10% fixed-rate, due February 2045	1,150.0	1,150.0
Senior Notes QQ, 4.90% fixed-rate, due May 2046	875.0	--
Senior Notes NN, 4.95% fixed-rate, due October 2054	400.0	400.0
TEPPCO senior debt obligations:		
TEPPCO Senior Notes, 6.65% fixed-rate, due April 2018	0.3	0.3
TEPPCO Senior Notes, 7.55% fixed-rate, due April 2038	0.4	0.4
Total principal amount of senior debt obligations	21,019.5	19,856.5
EPO Junior Subordinated Notes A, fixed/variable-rate, due August 2066 (1)	521.9	550.0

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EPO Junior Subordinated Notes C, fixed/variable-rate, due June 2067 (2)	259.5	285.8
EPO Junior Subordinated Notes B, fixed/variable-rate, due January 2068 (3)	682.7	682.7
TEPPCO Junior Subordinated Notes, fixed/variable-rate, due June 2067	14.2	14.2
Total principal amount of senior and junior debt obligations	22,497.8	21,389.2
Other, non-principal amounts	(37.7)	(25.4)
Less current maturities of debt (4)	(1,619.4)	(2,206.4)
Total long-term debt	\$20,840.7	\$19,157.4

(1) Fixed rate of 8.375% through August 1, 2016 (i.e., first call date without a make-whole redemption premium); thereafter, variable rate based on 3-month LIBOR plus 3.7075%. During the third quarter of 2015, EPO retired \$28.1 million of these junior notes.

(2) Fixed rate of 7.0% through September 1, 2017 (i.e., first call date without a make-whole redemption premium); thereafter, variable rate based on 3-month LIBOR plus 2.7775%. During the third quarter of 2015, EPO retired \$26.3 million of these junior notes.

(3) Fixed rate of 7.034% through January 15, 2018 (i.e., first call date without a make-whole redemption premium); thereafter, the rate will be the greater of 7.034% or a variable rate based on 3-month LIBOR plus 2.68%.

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

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

	Total	Scheduled Maturities of Debt					
		Remainder of	2015	2016	2017	2018	2019
Commercial Paper Notes	\$869.5	\$869.5	\$--	\$--	\$--	\$--	\$--
Senior Notes	20,150.0	--	750.0	800.0	1,100.0	1,500.0	16,000.0
Junior Subordinated Notes	1,478.3	--	--	--	--	--	1,478.3
Total	\$22,497.8	\$869.5	\$750.0	\$800.0	\$1,100.0	\$1,500.0	\$17,478.3

Parent-Subsidiary Guarantor Relationships

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

Issuance of \$2.5 Billion of Senior Notes in May 2015

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

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

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

Partial Retirement of Junior Subordinated Notes During Third Quarter of 2015

During the third quarter of 2015, EPO retired \$28.1 million of its Junior Subordinated Notes A and \$26.3 million of its Junior Subordinated Notes C with cash from operations. A \$1.4 million gain on the extinguishment of these debt obligations is included in "Other, net" on our Unaudited Condensed Statements of Consolidated Operations.

364-Day Credit Agreement

In September 2015, EPO amended its 364-Day Credit Agreement to extend its maturity date to September 2016. 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 2017. 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 2014 Form 10-K.

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Multi-Year Revolving Credit Facility

In September 2015, EPO amended its Multi-Year Revolving Credit Facility to increase its borrowing capacity from \$3.5 billion to \$4.0 billion and extend its maturity date from June 2018 to September 2020. The amended agreement also provides that EPO may increase its borrowing capacity to \$4.5 billion by allowing existing lenders under the facility to increase their respective commitments or by adding one or more new lenders to the facility. The remaining terms of the Multi-Year Revolving Credit Facility, as amended, remain materially the same as those reported for the Multi-Year Revolving Credit Facility in our 2014 Form 10-K.

Letters of Credit

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

Lender Financial Covenants

We were in compliance with the financial covenants of our consolidated debt agreements at September 30, 2015.

Information Regarding Variable Interest Rates Paid

The following table presents the range of interest rates and weighted-average interest rates paid on our consolidated variable-rate debt during the nine months ended September 30, 2015:

	Range of Interest Rates Paid	Weighted-Average Interest Rate Paid
Commercial Paper Notes	0.35% to 0.78%	0.59%
EPO Multi-Year Revolving Credit Facility	1.15% to 3.25%	1.30%

Note 11. Equity and Distributions

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

	Common Units (Unrestricted)	Restricted Common Units	Total Common Units
Number of units outstanding at December 31, 2014	1,933,095,027	4,229,790	1,937,324,817
Common units issued in connection with ATM program	23,258,453	--	23,258,453
Common units issued in connection with DRIP and EUPP	8,251,315	--	8,251,315
Common units issued in connection with Step 2 of Oiltanking acquisition	36,827,517	--	36,827,517
Common units issued in connection with the vesting and exercise of unit options	333,002	--	333,002
Common units issued in connection with the vesting of phantom unit awards	613,689	--	613,689
Common units issued in connection with the vesting of restricted common unit awards	1,997,194	(1,997,194)	--
Forfeiture of restricted common unit awards	--	(157,750)	(157,750)
Acquisition and cancellation of treasury units in connection with the	(680,496)	--	(680,496)

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vesting of equity-based awards

Other	15,054	--	15,054
Number of units outstanding at September 30, 2015	2,003,710,755	2,074,846	2,005,785,601

We may issue additional equity or debt securities to assist us in meeting our future liquidity and capital spending requirements. We have a universal shelf registration statement (the “2013 Shelf”) on file with the SEC. The 2013 Shelf allows Enterprise Products Partners L.P. and EPO (on a standalone basis) to issue an unlimited amount of equity and debt securities.

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On July 1, 2015, we filed a registration statement with the SEC covering the issuance of up to \$1.92 billion of our common units in amounts, at prices and on terms to be determined by market conditions and other factors at the time of such offerings. Pursuant to this “at-the-market” program (“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 August 3, 2015 and replaced our prior registration statement with respect to the ATM program, which was filed with the SEC in October 2013 and covered the issuance of up to \$1.25 billion of our common units. Immediately prior to the effectiveness of the new registration statement, we had the capacity to issue additional common units under the ATM program up to an aggregate sales price of \$424.6 million (after giving effect to sales of common units previously made under the program). Following the effectiveness of the new registration statement and after taking into account the aggregate sales price of common units sold under our ATM program through September 30, 2015 as described below, we now have the capacity to issue additional common units under our ATM program up to an aggregate sales price of \$1.92 billion.

During the nine months ended September 30, 2015, we issued 23,258,453 common units under the ATM program for aggregate gross proceeds of \$767.1 million. This includes 3,225,057 common units sold in March 2015 to a privately held affiliate of EPCO, which generated gross proceeds of \$100 million. After taking into account applicable costs, our transactions under the ATM program resulted in aggregate net cash proceeds of \$759.7 million during the nine months ended September 30, 2015. During the nine months ended September 30, 2014, we issued 1,590,334 common units under this program for aggregate gross cash proceeds of \$58.3 million, resulting in total net cash proceeds of \$57.7 million.

We also have registration statements on file with the SEC collectively authorizing the issuance of up to 140,000,000 of our common units in connection with a distribution reinvestment plan (“DRIP”). We issued a total of 7,965,318 common units under our DRIP during the nine months ended September 30, 2015, which generated net cash proceeds of \$242.8 million. During the nine months ended September 30, 2014, we issued 7,148,778 common units under our DRIP, which generated net cash proceeds of \$239.8 million. Privately held affiliates of EPCO reinvested \$50 million and \$75 million through the DRIP in each of the nine month periods ending September 30, 2015 and 2014, respectively (this amount being a component of the net cash proceeds presented for both periods). After taking into account the number of common units issued under the DRIP through September 30, 2015, we have the capacity to issue an additional 19,516,031 common units under this plan.

In addition to the DRIP, we have registration statements on file with the SEC authorizing the issuance of up to 8,000,000 of our common units in connection with our employee unit purchase plan (“EUPP”). We issued 285,997 common units under our EUPP during the nine months ended September 30, 2015, which generated net cash proceeds of \$8.9 million. During the nine months ended September 30, 2014, we issued 207,126 common units under our EUPP, which generated net cash proceeds of \$7.4 million. After taking into account the number of common units issued under the EUPP through September 30, 2015, we may issue an additional 6,867,071 common units under this plan.

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

Completion of Oiltanking Acquisition

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

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

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

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

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

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

We consider our purchase price allocation for the Oiltanking acquisition to be final. We finalized the determination of the fair value of the Liquidity Option Agreement during the third quarter of 2015. Subsequent changes in the fair value of this option will be recorded in earnings each reporting period until the option expires or is exercised.

Noncontrolling Interests

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

In July 2015, as part of the sale of our Offshore Business to Genesis, we sold our ownership interests in Independence Hub LLC and no longer report this third party ownership as noncontrolling interests.

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

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

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Accumulated Other Comprehensive Income (Loss)

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

	Gains (Losses) on Cash Flow Hedges	Interest Commodity Derivative Instruments	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)

	Gains (Losses) on Cash Flow Hedges	Interest Commodity Derivative Instruments	Rate Derivative Instruments	Other	Total
Balance, December 31, 2013	\$(14.7)	\$ (347.2)		\$ 2.9	\$(359.0)
Other comprehensive income before reclassifications	16.1	--		--	16.1
Amounts reclassified from accumulated other comprehensive loss	12.9	23.9		--	36.8
Total other comprehensive income	29.0	23.9		--	52.9
Balance, September 30, 2014	\$ 14.3	\$ (323.3)		\$ 2.9	\$(306.1)

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, 2015	2014	For the Nine Months Ended September 30, 2015	2014
Losses (gains) on cash flow hedges:					
Interest rate derivatives	Interest expense	\$8.9	\$8.0	\$26.3	\$23.9
Commodity derivatives	Revenue	(46.8)	(17.8)	(128.6)	14.5
Commodity derivatives	Operating costs and expenses	--	(0.2)	0.5	(1.6)
Total		\$(37.9)	\$(10.0)	\$(101.8)	\$36.8

Cash Distributions

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

Record Payment

	Distribution Date	Date
Per Common Unit		
2014:		
1st Quarter \$ 0.3550	4/30/2014	5/7/2014
2nd Quarter \$ 0.3600	7/31/2014	8/7/2014
3rd Quarter \$ 0.3650	10/31/2014	11/7/2014
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

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 expires at the end of calendar year 2015; therefore, distributions to be paid, if any, during calendar year 2016 will include all common units owned by the privately held affiliates of EPCO.

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Note 12. Business Segments

Our historical operations are reported under five business segments: (i) NGL Pipelines & Services, (ii) Crude Oil Pipelines & Services, (iii) Natural Gas Pipelines & Services, (iv) Petrochemical & Refined Products Services and (v) Offshore Pipelines & Services. Our business segments are generally organized and managed according to the types of services rendered (or technologies employed) and products produced and/or sold.

Our consolidated financial statements reflect ownership of the Offshore Business through July 24, 2015, which was the closing date of the sales transaction. See Note 6 for additional information related to the sale of our Offshore Business.

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

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by our executive management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income.

In total, gross operating margin represents operating income exclusive of (1) depreciation, amortization and accretion expenses, (2) impairment charges, (3) gains and losses attributable to asset sales and insurance recoveries and (4) general and administrative costs. Gross operating margin includes equity in income of unconsolidated affiliates and non-refundable deferred transportation revenues relating to the make-up rights of committed shippers associated with certain pipelines. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intercompany transactions. In accordance with GAAP, intercompany accounts and transactions are eliminated in consolidation. Gross operating margin is exclusive of other income and expense transactions, income taxes, the cumulative effect of changes in accounting principles and extraordinary charges. Gross operating margin is presented on a 100% basis before any allocation of earnings to noncontrolling interests.

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

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2015	2014	2015	2014
Revenues	\$6,307.9	\$12,330.2	\$20,872.9	\$37,760.9
Subtract operating costs and expenses	(5,452.6)	(11,414.8)	(18,426.5)	(34,934.4)
Add equity in income of unconsolidated affiliates	103.1	72.3	302.5	179.1
Add depreciation, amortization and accretion expense amounts not reflected in gross operating margin	351.1	322.7	1,082.0	936.5
Add impairment charges not reflected in gross operating margin	26.8	5.7	139.1	18.2
Add net losses or subtract net gains attributable to asset sales and insurance recoveries not reflected in gross operating margin (see Note 16)	12.3	(2.6)	14.7	(99.0)
Add non-refundable deferred revenues attributable to shipper make-up rights on new pipeline projects reflected in gross operating margin	3.4	21.6	39.3	66.8
Subtract subsequent recognition of deferred revenues attributable to make-up rights not reflected in gross operating margin	(10.9)	--	(45.3)	--
Total segment gross operating margin	\$1,341.1	\$1,335.1	\$3,978.7	\$3,928.1

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2015	2014	2015	2014
Total segment gross operating margin	\$1,341.1	\$1,335.1	\$3,978.7	\$3,928.1
Adjustments to reconcile total segment gross operating margin to operating income:				
Subtract depreciation, amortization and accretion expense amounts not reflected in gross operating margin	(351.1)	(322.7)	(1,082.0)	(936.5)
Subtract impairment charges not reflected in gross operating margin	(26.8)	(5.7)	(139.1)	(18.2)
Add net gains or subtract net losses attributable to asset sales and insurance recoveries not reflected in gross operating margin	(12.3)	2.6	(14.7)	99.0
Subtract non-refundable deferred revenues attributable to shipper make-up rights on new pipeline projects reflected in gross operating margin	(3.4)	(21.6)	(39.3)	(66.8)
Add subsequent recognition of deferred revenues attributable to make-up rights not reflected in gross operating margin	10.9	--	45.3	--
Subtract general and administrative costs not reflected in gross operating margin	(49.0)	(50.0)	(143.2)	(150.9)
Operating income	909.4	937.7	2,605.7	2,854.7
Other expense, net	(246.2)	(230.8)	(736.4)	(679.8)

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Income before income taxes	\$663.2	\$706.9	\$1,869.3	\$2,174.9
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ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

	Reportable Business Segments						Consolidated Total
	NGL Pipelines & Services	Crude Oil Pipelines & Services	Natural Gas Pipelines & Services	Petrochemical & Refined Products Services	Offshore Pipelines & Services	Adjustments and Eliminations	
Revenues from third parties:							
Three months ended September 30, 2015	\$2,284.6	\$2,316.4	\$705.2	\$ 980.0	\$7.8	\$ --	\$ 6,294.0
Three months ended September 30, 2014	4,024.0	5,435.6	1,026.5	1,792.0	41.1	--	12,319.2
Nine months ended September 30, 2015	7,223.2	8,080.4	2,117.5	3,347.6	76.9	--	20,845.6
Nine months ended September 30, 2014	13,217.2	16,236.6	3,261.0	4,869.9	112.4	--	37,697.1
Revenues from related parties:							
Three months ended September 30, 2015	2.2	6.2	4.5	--	1.0	--	13.9
Three months ended September 30, 2014	2.7	1.5	5.4	--	1.4	--	11.0
Nine months ended September 30, 2015	6.0	8.6	10.8	--	1.9	--	27.3
Nine months ended September 30, 2014	10.2	31.1	16.5	--	6.0	--	63.8
Intersegment and intrasegment revenues:							
Three months ended September 30, 2015	2,461.0	1,142.1	180.2	267.3	0.1	(4,050.7)	--
Three months ended September 30, 2014	3,603.8	2,529.5	231.0	452.2	1.2	(6,817.7)	--
Nine months ended September 30, 2015	7,685.1	3,958.9	519.7	875.8	0.6	(13,040.1)	--
Nine months ended September 30, 2014	10,789.7	10,714.5	835.8	1,317.6	4.8	(23,662.4)	--
Total revenues:							
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
Three months ended September 30, 2014	7,630.5	7,966.6	1,262.9	2,244.2	43.7	(6,817.7)	12,330.2
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
	24,017.1	26,982.2	4,113.3	6,187.5	123.2	(23,662.4)	37,760.9

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Nine months ended
September 30, 2014
Equity in income (loss) of
unconsolidated affiliates:

Three months ended September 30, 2015	18.9	81.2	0.9	(3.3)	5.4	--	103.1
Three months ended September 30, 2014	11.7	46.8	0.9	(4.2)	17.1	--	72.3
Nine months ended September 30, 2015	43.0	220.5	2.8	(10.4)	46.6	--	302.5
Nine months ended September 30, 2014	19.2	131.7	2.7	(10.3)	35.8	--	179.1
Gross operating margin:								
Three months ended September 30, 2015	695.5	254.6	192.4	191.5		7.1	--	1,341.1
Three months ended September 30, 2014	711.5	190.8	195.4	190.3		47.1	--	1,335.1
Nine months ended September 30, 2015	2,041.3	704.2	588.3	547.4		97.5	--	3,978.7
Nine months ended September 30, 2014	2,172.4	534.5	618.8	482.4		120.0	--	3,928.1
Property, plant and equipment, net:								
(see Note 6)								
At September 30, 2015	12,192.8	3,550.0	8,680.6	3,013.5	--	3,777.2		31,214.1
At December 31, 2014	11,766.9	2,332.2	8,835.5	3,047.2	1,145.1	2,754.7		29,881.6
Investments in unconsolidated affiliates:								
(see Note 7)								
At September 30, 2015	708.9	1,817.9	23.1	75.4	--	--		2,625.3
At December 31, 2014	682.3	1,767.7	23.2	75.1	493.7	--		3,042.0
Intangible assets, net: (see Note 9)								
At September 30, 2015	460.4	2,402.3	1,025.7	193.7	--	--		4,082.1
At December 31, 2014	689.2	2,223.6	972.9	374.8	41.6	--		4,302.1
Goodwill: (see Note 9)								
At September 30, 2015	2,651.7	1,842.8	296.3	958.4	--	--		5,749.2
At December 31, 2014	2,210.2	918.7	296.3	793.0	82.0	--		4,300.2
Segment assets:								
At September 30, 2015	16,013.8	9,613.0	10,025.7	4,241.0	--	3,777.2		43,670.7
At December 31, 2014	15,348.6	7,242.2	10,127.9	4,290.1	1,762.4	2,754.7		41,525.9

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ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2015	2014	2015	2014
NGL Pipelines & Services:				
Sales of NGLs and related products	\$1,844.9	\$3,603.4	\$5,936.2	\$12,029.8
Midstream services	441.9	423.3	1,293.0	1,197.6
Total	2,286.8	4,026.7	7,229.2	13,227.4
Crude Oil Pipelines & Services:				
Sales of crude oil	2,147.3	5,348.2	7,689.3	16,003.5
Midstream services	175.3	88.9	399.7	264.2
Total	2,322.6	5,437.1	8,089.0	16,267.7
Natural Gas Pipelines & Services:				
Sales of natural gas	455.0	775.5	1,361.2	2,515.7
Midstream services	254.7	256.4	767.1	761.8
Total	709.7	1,031.9	2,128.3	3,277.5
Petrochemical & Refined Products Services:				
Sales of petrochemicals and refined products	780.5	1,605.4	2,764.2	4,338.2
Midstream services	199.5	186.6	583.4	531.7
Total	980.0	1,792.0	3,347.6	4,869.9
Offshore Pipelines & Services:				
Sales of natural gas	--	--	--	0.2
Sales of crude oil	0.4	2.5	3.2	7.5
Midstream services	8.4	40.0	75.6	110.7
Total	8.8	42.5	78.8	118.4
Total consolidated revenues	\$6,307.9	\$12,330.2	\$20,872.9	\$37,760.9
Consolidated costs and expenses				
Operating costs and expenses:				
Cost of sales	\$4,419.9	\$10,455.1	\$15,355.9	\$32,213.1
Other operating costs and expenses (1)	642.5	633.9	1,834.8	1,865.6
Depreciation, amortization and accretion	351.1	322.7	1,082.0	936.5
Net losses (gains) attributable to asset sales and insurance recoveries	12.3	(2.6)	14.7	(99.0)
Non-cash asset impairment charges	26.8	5.7	139.1	18.2
General and administrative costs	49.0	50.0	143.2	150.9
Total consolidated costs and expenses	\$5,501.6	\$11,464.8	\$18,569.7	\$35,085.3

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

Fluctuations in our product sales revenues and related cost of sales amounts are explained in part by changes in energy commodity prices. In general, lower energy commodity prices result in a decrease in our revenues attributable to

product sales; however, these lower commodity prices also decrease the associated cost of sales as purchase costs decline. The same correlation would be true in the case of higher energy commodity sales prices and purchase costs.

Note 13. Related Party Transactions

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

	For the Three Months Ended September 30, 2015		For the Nine Months Ended September 30, 2014	
Revenues – related parties:				
Unconsolidated affiliates	\$13.9	\$11.0	\$27.3	\$63.8
Costs and expenses – related parties:				
EPCO and its privately held affiliates	\$246.0	\$212.8	\$703.9	\$688.0
Unconsolidated affiliates	66.9	35.8	165.3	138.4
Total	\$312.9	\$248.6	\$869.2	\$826.4

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ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

	September 30, 2015	December 31, 2014
Accounts receivable - related parties:		
Unconsolidated affiliates	\$ 1.7	\$ 2.8
Accounts payable - related parties:		
EPCO and its privately held affiliates	\$ 64.6	\$ 98.1
Unconsolidated affiliates	15.7	20.8
Total	\$ 80.3	\$ 118.9

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

Relationship with EPCO and its Privately Held 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, 2015, 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
675,259,617	33.7%

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 certain of the privately held affiliates at September 30, 2015. 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, 2015 and 2014, we paid EPCO and its privately held affiliates cash distributions totaling \$705.9 million and \$652.8 million, respectively. Distributions paid during the nine months ended September 30, 2015 excluded 35,380,000 Designated Units (see Note 11). Likewise, distributions paid during the nine months ended September 30, 2014 excluded 45,120,000 Designated Units.

From time-to-time, EPCO and its privately held affiliates elect to reinvest a portion of the cash distributions they receive from us into the purchase of additional common units under our DRIP. These purchases totaled \$50 million

and \$75 million for the nine months ended September 30, 2015 and 2014, respectively. In addition, a total of \$50 million of distributions were reinvested in connection with the distribution we paid on November 6, 2015. In March 2015, a privately held affiliate of EPCO purchased 3,225,057 common units from us under our ATM program for \$31.01 per unit. See Note 11 for additional information regarding our DRIP and ATM program.

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ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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, 2015		For the Nine Months Ended September 30, 2014	
Operating costs and expenses	\$215.3	\$179.0	\$612.2	\$591.6
General and administrative expenses	26.4	29.6	78.8	84.5
Total costs and expenses	\$241.7	\$208.6	\$691.0	\$676.1

Note 14. Earnings Per Unit

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

	For the Three Months Ended September 30, 2015		For the Nine Months Ended September 30, 2014	
BASIC EARNINGS PER UNIT				
Net income attributable to limited partners	\$649.3	\$691.1	\$1,836.4	\$2,127.6
Undistributed earnings allocated and cash payments on phantom unit awards (1)	(2.2)	(1.3)	(6.6)	(4.0)
Net income available to common unitholders	\$647.1	\$689.8	\$1,829.8	\$2,123.6
Basic weighted-average number of common units outstanding	1,969.3	1,834.2	1,952.3	1,831.1
Basic earnings per unit	\$0.33	\$0.38	\$0.94	\$1.16
DILUTED EARNINGS PER UNIT				
Net income attributable to limited partners	\$649.3	\$691.1	\$1,836.4	\$2,127.6
Diluted weighted-average number of units outstanding:				
Distribution-bearing common units	1,969.3	1,834.2	1,952.3	1,831.1
Designated Units	35.4	45.1	35.4	45.1
Phantom units (1)	5.7	3.4	5.4	2.8
Incremental option units	0.1	0.7	0.2	1.0
Total	2,010.5	1,883.4	1,993.3	1,880.0
Diluted earnings per unit	\$0.32	\$0.37	\$0.92	\$1.13

(1) Each phantom unit award includes a DER, which entitles the recipient to receive cash payments equal to the product of the number of phantom unit awards and the cash distribution per unit paid to our common unitholders.

Cash payments made in connection with DERs are nonforfeitable. As a result, the phantom units are considered participating securities for purposes of computing basic earnings per unit. Phantom unit awards were first issued in February 2014.

Note 15. Commitments and Contingencies

Litigation

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

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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, 2015 and December 31, 2014, our accruals for litigation contingencies were \$4.6 million and \$2.4 million, respectively, and were recorded in our Unaudited Condensed Consolidated Balance Sheets as a component of "Other current liabilities." Our evaluation of litigation contingencies is based on the facts and circumstances of each case and predicting the outcome of these matters involves uncertainties. In the event the assumptions we use to evaluate these matters change in future periods or new information becomes available, we may be required to record additional accruals. In an effort to mitigate expenses associated with litigation, we may settle legal proceedings out of court.

ETP Matter

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

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

We do not believe that the verdict or the judgment entered against us is supported by the evidence or the law. 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. We intend to vigorously oppose the judgment through the appeals process. As of September 30, 2015, we have not recorded a provision for this matter as management believes payment of damages in this case is not probable.

FTC Matter

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

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ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Contractual Obligations

Scheduled Maturities of Debt

We have long-term and short-term payment obligations under debt agreements. See Note 10 for additional information regarding our scheduled future maturities of debt principal.

Operating Lease Obligations

Consolidated lease and rental expense was \$28.8 million and \$23.5 million during the third quarters of 2015 and 2014, respectively. For the nine months ended September 30, 2015 and 2014, consolidated lease and rental expense was \$76.4 million and \$69.2 million, respectively. Our operating lease commitments at September 30, 2015 did not differ materially from those reported in our 2014 Form 10-K.

Purchase Obligations

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

Other Commitments

In connection with the agreements to acquire EFS Midstream (see Note 8), we are obligated to spend up to an aggregate of \$270 million on specified midstream gathering assets for Pioneer and Reliance, if requested by these producers, over a ten year period. If constructed, these new assets would be owned by us and be a component of the EFS Midstream asset network.

Liquidity Option Agreement

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

During 2015, we retrospectively adjusted our provisional fair value estimate for the Liquidity Option Agreement from \$119.4 million to \$219.7 million. The retrospective adjustment was applied in our December 31, 2014 Consolidated Balance Sheet as a \$100.3 million increase in goodwill and a corresponding increase in the Liquidity Option Agreement liability, which is a component of "Other long-term liabilities." The retrospective adjustment did not impact our historical results of operations, cash flows or other balance sheet amounts.

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

Our initial fair value estimate of \$119.4 million was based on a variety of assumptions (each a Level 3 input), including a key assumption that a market participant would maintain the OTA corporate structure and not divest of its Enterprise common units for 30 years following exercise of the option in 2020. After further consideration, we revised this key assumption to reflect that a market participant might elect to dissolve the OTA corporate structure and sell the Enterprise common units at earlier dates. Accordingly, for purposes of our discounted cash flow model, we assigned

an equal probability to the divestiture of OTA and its assets over each of the 30 years in our forecast period. As a result, our provisional fair value estimate at October 1, 2014 increased by \$100.3 million to \$219.7 million, with a corresponding \$100.3 million increase in goodwill which has been retrospectively adjusted as of December 31, 2014. This change is not considered material to our consolidated financial statements. None of the other key valuation assumptions we listed in our 2014 Form 10-K for the Liquidity Option Agreement have changed. We finalized the determination of the initial fair value of the Liquidity Option Agreement during the third quarter of 2015.

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ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Results for the three and nine months ended September 30, 2015 include \$4.3 million and \$15.8 million, respectively, of non-cash accretion expense associated with the change in fair value of the Liquidity Option Agreement from October 1, 2014 through September 30, 2015. The carrying value of the Liquidity Option Agreement, which is a component of “Other long-term liabilities” on our Unaudited Condensed Consolidated Balance Sheet, increased to \$235.5 million at September 30, 2015 as of result of accretion.

Note 16. Supplemental Cash Flow Information

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

	For the Nine Months Ended September 30,	
	2015	2014
Decrease (increase) in:		
Accounts receivable – trade	\$1,042.5	\$153.6
Accounts receivable – related parties	1.2	4.0
Inventories	(143.2)	(536.9)
Prepaid and other current assets	(32.7)	(44.5)
Other assets	2.1	20.0
Increase (decrease) in:		
Accounts payable – trade	(72.7)	(14.2)
Accounts payable – related parties	(38.6)	(27.7)
Accrued product payables	(1,248.4)	(13.1)
Accrued interest	(136.7)	(131.7)
Other current liabilities	(13.8)	143.5
Other liabilities	12.4	11.2
Net effect of changes in operating accounts	\$(627.9)	\$(435.8)

We incurred liabilities for construction in progress that had not been paid at September 30, 2015 and December 31, 2014 of \$495.1 million and \$372.8 million, respectively. Such amounts are not included under the caption “Capital expenditures” on the Unaudited Condensed Statements of Consolidated Cash Flows.

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

In addition, we incurred a \$1.0 billion payable in connection with our acquisition of EFS Midstream in July 2015 that will be paid no later than the first anniversary of the closing date of the acquisition (see Note 8).

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

proceeds. This gain was classified as a reduction in operating costs and expenses for the period.

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NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

	For the Nine Months Ended September 30,	
	2015	2014
Sale of Offshore Business (see Note 6)	\$1,528.6	\$--
Insurance recoveries attributable to West Storage claims	--	95.0
Other cash proceeds	8.7	26.5
Total	\$1,537.3	\$121.5

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,	
	2015	2014
Sale of Offshore Business (see Note 6)	\$(12.6)	\$--
Gains attributable to West Storage insurance recoveries	--	95.0
Net gains (losses) attributable to other asset sales	(2.1)	4.0
Total	\$(14.7)	\$99.0

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ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Note 17. Condensed Consolidating Financial Information

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

EPO has issued publicly traded debt securities. As the parent company of EPO, Enterprise Products Partners L.P. guarantees substantially all of the debt obligations of EPO. If EPO were to default on any of its guaranteed debt, Enterprise Products Partners L.P. would be responsible for full and unconditional repayment of that obligation. See Note 10 for additional information regarding our consolidated debt obligations.

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

Enterprise Products Partners L.P.

Unaudited Condensed Consolidating Balance Sheet

September 30, 2015

	EPO and Subsidiaries				Enterprise Products			
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total	
ASSETS								
Current assets:								
Cash and cash equivalents and restricted cash	\$46.9	\$ 85.3	\$(5.5)	\$ 126.7	\$ --	\$ --	\$ 126.7	
Accounts receivable – trade, net	791.0	2,011.3	(0.3)	2,802.0	--	--	2,802.0	
Accounts receivable – related parties	123.1	780.8	(901.5)	2.4	--	(0.7)	1.7	
Inventories	889.1	196.6	(0.3)	1,085.4	--	--	1,085.4	
Derivative assets	139.1	102.7	--	241.8	--	--	241.8	
Prepaid and other current assets	164.7	247.7	(10.2)	402.2	0.2	--	402.4	
Total current assets	2,153.9	3,424.4	(917.8)	4,660.5	0.2	(0.7)	4,660.0	
Property, plant and equipment, net	3,432.3	27,780.4	1.4	31,214.1	--	--	31,214.1	
Investments in unconsolidated affiliates	38,310.0	4,094.7	(39,779.4)	2,625.3	20,397.5	(20,397.5)	2,625.3	
Intangible assets, net	726.8	3,370.1	(14.8)	4,082.1	--	--	4,082.1	
Goodwill	459.1	5,290.1	--	5,749.2	--	--	5,749.2	
Other assets	226.4	49.0	(78.8)	196.6	0.5	--	197.1	
Total assets	\$45,308.5	\$ 44,008.7	\$(40,789.4)	\$ 48,527.8	\$ 20,398.2	\$(20,398.2)	\$ 48,527.8	

**LIABILITIES AND
EQUITY**
Current liabilities:
Current maturities of

debt	\$1,619.3	\$0.1	\$--	\$1,619.4	\$--	\$--	\$1,619.4
Accounts payable – trade	331.4	519.0	(5.5)	844.9	--	--	844.9
Accounts payable – related parties	866.7	130.1	(916.5)	80.3	0.7	(0.7)	80.3
Accrued product payables	938.0	1,611.2	(1.3)	2,547.9	--	--	2,547.9
Accrued liability related to EFS Midstream acquisition	--	997.7	--	997.7	--	--	997.7
Accrued interest	198.6	0.3	--	198.9	--	--	198.9
Other current liabilities	174.3	425.1	(10.0)	589.4	(0.1)	0.5	589.8
Total current liabilities	4,128.3	3,683.5	(933.3)	6,878.5	0.6	(0.2)	6,878.9
Long-term debt	20,825.4	15.3	--	20,840.7	--	--	20,840.7
Deferred tax liabilities	3.2	47.4	(1.0)	49.6	--	3.8	53.4
Other long-term liabilities	10.6	234.3	(78.5)	166.4	235.5	--	401.9
Commitments and contingencies							
Equity:							
Partners' and other owners' equity	20,341.0	39,986.1	(39,954.0)	20,373.1	20,162.1	(20,373.1)	20,162.1
Noncontrolling interests	--	42.1	177.4	219.5	--	(28.7)	190.8
Total equity	20,341.0	40,028.2	(39,776.6)	20,592.6	20,162.1	(20,401.8)	20,352.9
Total liabilities and equity	\$45,308.5	\$44,008.7	\$(40,789.4)	\$48,527.8	\$20,398.2	\$(20,398.2)	\$48,527.8

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ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Enterprise Products Partners L.P.

Unaudited Condensed Consolidating Balance Sheet

December 31, 2014

	EPO and Subsidiaries		EPO and Subsidiaries		Enterprise Products			
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total	
ASSETS								
Current assets:								
Cash and cash equivalents and restricted cash	\$ 18.7	\$ 70.4	\$ (14.7)	\$ 74.4	\$ --	\$ --	\$ 74.4	
Accounts receivable – trade, net	1,128.5	2,698.2	(3.7)	3,823.0	--	--	3,823.0	
Accounts receivable – related parties	158.8	1,114.6	(1,266.6)	6.8	--	(4.0)	2.8	
Inventories	831.8	182.8	(0.4)	1,014.2	--	--	1,014.2	
Derivative assets	102.0	124.0	--	226.0	--	--	226.0	
Prepaid and other current assets	435.7	222.3	(308.5)	349.5	--	0.8	350.3	
Total current assets	2,675.5	4,412.3	(1,593.9)	5,493.9	--	(3.2)	5,490.7	
Property, plant and equipment, net	2,871.7	26,912.0	97.9	29,881.6	--	--	29,881.6	
Investments in unconsolidated affiliates	36,937.5	3,556.4	(37,451.9)	3,042.0	18,287.5	(18,287.5)	3,042.0	
Intangible assets, net	2,527.3	1,292.4	482.4	4,302.1	--	--	4,302.1	
Goodwill	1,956.1	1,721.4	622.7	4,300.2	--	--	4,300.2	
Other assets	139.3	45.8	(0.7)	184.4	--	--	184.4	
Total assets	\$ 47,107.4	\$ 37,940.3	\$ (37,843.5)	\$ 47,204.2	\$ 18,287.5	\$ (18,290.7)	\$ 47,201.0	
LIABILITIES AND EQUITY								
Current liabilities:								
Current maturities of debt	\$ 2,206.4	\$ --	\$ --	\$ 2,206.4	\$ --	\$ --	\$ 2,206.4	
Accounts payable – trade	216.6	571.4	(14.8)	773.2	0.6	--	773.8	
Accounts payable – related parties	1,226.5	173.3	(1,280.9)	118.9	4.0	(4.0)	118.9	
Accrued product payables	1,570.0	2,287.9	(4.6)	3,853.3	--	--	3,853.3	
Accrued interest	335.4	0.7	(0.6)	335.5	--	--	335.5	
Other current liabilities	130.8	763.7	(308.7)	585.8	--	--	585.8	
Total current liabilities	5,685.7	3,797.0	(1,609.6)	7,873.1	4.6	(4.0)	7,873.7	
Long-term debt	19,142.5	14.9	--	19,157.4	--	--	19,157.4	

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Deferred tax liabilities	4.9	58.5	(0.9)	62.5	--	4.1	66.6
Other long-term liabilities	10.9	180.8	(0.3)	191.4	219.7	--	411.1
Commitments and contingencies							
Equity:							
Partners' and other owners' equity	22,263.4	33,820.9	(37,820.6)	18,263.7	18,063.2	(18,263.7)	18,063.2
Noncontrolling interests	--	68.2	1,587.9	1,656.1	--	(27.1)	1,629.0
Total equity	22,263.4	33,889.1	(36,232.7)	19,919.8	18,063.2	(18,290.8)	19,692.2
Total liabilities and equity	\$47,107.4	\$37,940.3	\$(37,843.5)	\$47,204.2	\$18,287.5	\$(18,290.7)	\$47,201.0

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ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Enterprise Products Partners L.P.

Unaudited Condensed Consolidating Statement of Operations

For the Three Months Ended September 30, 2015

	EPO and Subsidiaries				Enterprise Products		
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	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 loss (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 Three Months Ended September 30, 2014

	EPO and Subsidiaries				Enterprise Products		
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Revenues	\$8,121.5	\$8,598.2	\$ (4,389.5)	\$ 12,330.2	\$ --	\$ --	\$ 12,330.2
Costs and expenses:							
Operating costs and expenses	7,950.9	7,853.5	(4,389.6)	11,414.8	--	--	11,414.8
	8.2	40.4	--	48.6	1.4	--	50.0

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General and administrative costs

Total costs and expenses	7,959.1	7,893.9	(4,389.6)	11,463.4	1.4	--	11,464.8
Equity in income of unconsolidated affiliates	762.5	94.4	(784.6)	72.3	692.5	(692.5)	72.3
Operating income	924.9	798.7	(784.5)	939.1	691.1	(692.5)	937.7
Other income (expense):							
Interest expense	(229.2)	(0.6)	--	(229.8)	--	--	(229.8)
Other, net	0.2	(1.2)	--	(1.0)	--	--	(1.0)
Total other expense, net	(229.0)	(1.8)	--	(230.8)	--	--	(230.8)
Income before income taxes	695.9	796.9	(784.5)	708.3	691.1	(692.5)	706.9
Provision for income taxes	(4.0)	(2.8)	--	(6.8)	--	(0.9)	(7.7)
Net income	691.9	794.1	(784.5)	701.5	691.1	(693.4)	699.2
Net income attributable to noncontrolling interests	--	0.1	(9.5)	(9.4)	--	1.3	(8.1)
Net income attributable to entity	\$691.9	\$794.2	\$(794.0)	\$692.1	\$691.1	\$(692.1)	\$691.1

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ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Enterprise Products Partners L.P.

Unaudited Condensed Consolidating Statement of Operations

For the Nine Months Ended September 30, 2015

	EPO and Subsidiaries				Enterprise		
	Subsidiary	Other	EPO and	Consolidated	Products	Eliminations	Consolidated
	Issuer	Subsidiaries	Subsidiaries	EPO and	Partners	and	Total
	(EPO)	(Non-	and	Subsidiaries	L.P.	Adjustments	
		guarantor)	Adjustments		(Guarantor)		
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 Operations

For the Nine Months Ended September 30, 2014

	EPO and Subsidiaries				Enterprise		
	Subsidiary	Other	EPO and	Consolidated	Products	Eliminations	Consolidated
	Issuer	Subsidiaries	Subsidiaries	EPO and	Partners	and	Total
	(EPO)	(Non-	and	Subsidiaries	L.P.	Adjustments	
		guarantor)	Adjustments		(Guarantor)		
Revenues	\$ 25,190.1	\$ 25,859.9	\$ (13,289.1)	\$ 37,760.9	\$ --	\$ --	\$ 37,760.9

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Costs and expenses:

Operating costs and expenses	24,516.6	23,707.6	(13,289.8)	34,934.4	--	--	34,934.4
General and administrative costs	23.1	126.0	--	149.1	1.8	--	150.9
Total costs and expenses	24,539.7	23,833.6	(13,289.8)	35,083.5	1.8	--	35,085.3
Equity in income of unconsolidated affiliates	2,169.5	256.1	(2,246.5)	179.1	2,129.4	(2,129.4)	179.1
Operating income	2,819.9	2,282.4	(2,245.8)	2,856.5	2,127.6	(2,129.4)	2,854.7
Other income (expense):							
Interest expense	(678.6)	(1.0)	--	(679.6)	--	--	(679.6)
Other, net	0.7	(0.9)	--	(0.2)	--	--	(0.2)
Total other expense, net	(677.9)	(1.9)	--	(679.8)	--	--	(679.8)
Income before income taxes	2,142.0	2,280.5	(2,245.8)	2,176.7	2,127.6	(2,129.4)	2,174.9
Provision for income taxes	(15.5)	(5.8)	0.2	(21.1)	--	(1.4)	(22.5)
Net income	2,126.5	2,274.7	(2,245.6)	2,155.6	2,127.6	(2,130.8)	2,152.4
Net income attributable to noncontrolling interests	--	0.2	(28.8)	(28.6)	--	3.8	(24.8)
Net income attributable to entity	\$2,126.5	\$2,274.9	\$(2,274.4)	\$2,127.0	\$2,127.6	\$(2,127.0)	\$2,127.6

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ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Enterprise Products Partners L.P.

Unaudited Condensed Consolidating Statement of Comprehensive Income

For the Three Months Ended September 30, 2015

	EPO and Subsidiaries		EPO and Subsidiaries		Enterprise Products Partners L.P.		Eliminations and Consolidated	
	Subsidiaries	Other Subsidiaries	Subsidiaries	Eliminations	Subsidiaries	Eliminations	and Consolidated	Consolidated
	Issuer (EPO)	(Non-guarantor)	and Adjustments	EPO and Subsidiaries	L.P. (Guarantor)	and Adjustments	Total	
Comprehensive income	\$676.0	\$ 797.3	\$ (763.9)	\$ 709.4	\$ 697.2	\$ (701.0)	\$ 705.6	
Comprehensive loss (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 Three Months Ended September 30, 2014

	EPO and Subsidiaries		EPO and Subsidiaries		Enterprise Products Partners L.P.		Eliminations and Consolidated	
	Subsidiaries	Other Subsidiaries	Subsidiaries	Eliminations	Subsidiaries	Eliminations	and Consolidated	Consolidated
	Issuer (EPO)	(Non-guarantor)	and Adjustments	EPO and Subsidiaries	L.P. (Guarantor)	and Adjustments	Total	
Comprehensive income	\$708.9	\$ 825.2	\$ (784.5)	\$ 749.6	\$ 739.2	\$ (741.5)	\$ 747.3	
Comprehensive loss (income) attributable to noncontrolling interests	--	0.1	(9.5)	(9.4)	--	1.3	(8.1)	
Comprehensive income attributable to entity	\$708.9	\$ 825.3	\$ (794.0)	\$ 740.2	\$ 739.2	\$ (740.2)	\$ 739.2	

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ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Enterprise Products Partners L.P.

Unaudited Condensed Consolidating Statement of Comprehensive Income

For the 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 Comprehensive Income

For the Nine Months Ended September 30, 2014

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Comprehensive income	\$ 2,161.8	\$ 2,292.2	\$ (2,245.5)	\$ 2,208.5	\$ 2,180.5	\$ (2,183.7)	\$ 2,205.3
Comprehensive loss							
(income) attributable to noncontrolling interests	--	0.2	(28.8)	(28.6)	--	3.8	(24.8)
Comprehensive income attributable to entity	\$ 2,161.8	\$ 2,292.4	\$ (2,274.3)	\$ 2,179.9	\$ 2,180.5	\$ (2,179.9)	\$ 2,180.5

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ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Enterprise Products Partners L.P.

Unaudited Condensed Consolidating Statement of Cash Flows

For the 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 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 and insurance recoveries	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)

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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 partners	(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

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ENTERPRISE PRODUCTS PARTNERS L.P.

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Enterprise Products Partners L.P.

Unaudited Condensed Consolidating Statement of Cash Flows

For the Nine Months Ended September 30, 2014

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Operating activities:							
Net income	\$2,126.5	\$ 2,274.7	\$ (2,245.6)	\$ 2,155.6	\$ 2,127.6	\$ (2,130.8)	\$ 2,152.4
Reconciliation of net income to net cash flows provided by operating activities:							
Depreciation, amortization and accretion	114.3	878.5	(0.4)	992.4	--	--	992.4
Equity in income of unconsolidated affiliates	(2,169.5)	(256.1)	2,246.5	(179.1)	(2,129.4)	2,129.4	(179.1)
Distributions received from unconsolidated affiliates	3,475.8	229.0	(3,444.1)	260.7	2,007.4	(2,007.4)	260.7
Net effect of changes in operating accounts and other operating activities	(764.6)	230.1	16.7	(517.8)	(5.6)	1.4	(522.0)
Net cash flows provided by operating activities	2,782.5	3,356.2	(3,426.9)	2,711.8	2,000.0	(2,007.4)	2,704.4
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(329.1)	(1,530.4)	--	(1,859.5)	--	--	(1,859.5)
Proceeds from asset sales and insurance recoveries	4.2	117.3	--	121.5	--	--	121.5
Other investing activities	(2,059.3)	(526.9)	2,056.1	(530.1)	(300.7)	300.7	(530.1)
Cash used in investing activities	(2,384.2)	(1,940.0)	2,056.1	(2,268.1)	(300.7)	300.7	(2,268.1)
Financing activities:							
Borrowings under debt agreements	7,167.5	--	--	7,167.5	--	--	7,167.5
Repayments of debt	(4,856.3)	--	--	(4,856.3)	--	--	(4,856.3)
Cash distributions paid to partners	(2,007.4)	(3,473.6)	3,473.6	(2,007.4)	(1,948.2)	2,007.4	(1,948.2)
Cash payments made in connection with DERs	--	--	--	--	(2.4)	--	(2.4)
	--	--	(29.4)	(29.4)	--	--	(29.4)

Cash distributions paid to noncontrolling interests							
Cash contributions from noncontrolling interests	--	--	4.0	4.0	--	--	4.0
Net cash proceeds from issuance of common units	--	--	--	--	304.9	--	304.9
Cash contributions from owners	300.7	2,060.0	(2,060.0)	300.7	--	(300.7)	--
Other financing activities	(18.1)	--	--	(18.1)	(53.6)	--	(71.7)
Cash provided by (used in) financing activities	586.4	(1,413.6)	1,388.2	561.0	(1,699.3)	1,706.7	568.4
Net change in cash and cash equivalents	984.7	2.6	17.4	1,004.7	--	--	1,004.7
Cash and cash equivalents, January 1	28.4	49.5	(21.0)	56.9	--	--	56.9
Cash and cash equivalents, September 30	\$1,013.1	\$ 52.1	\$ (3.6)	\$ 1,061.6	\$--	\$--	\$ 1,061.6

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

For the Three and Nine Months Ended September 30, 2015 and 2014.

The following information should be read in conjunction with our Unaudited Condensed Consolidated Financial Statements and accompanying Notes included in this quarterly report on Form 10-Q and the Audited Consolidated Financial Statements and related Notes, together with our discussion and analysis of financial position and results of operations, included in our annual report on Form 10-K for the year ended December 31, 2014, as filed on March 2, 2015 (the "2014 Form 10-K"). Our financial statements have been prepared in accordance with generally accepted accounting principles ("GAAP") in the United States ("U.S.").

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

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

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

In addition to owning our general partner, EPCO and its privately held affiliates owned approximately 33.7% of our limited partner interests at September 30, 2015.

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

References to "Offshore 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"). See "Significant Recent Developments" within this Part I, Item 2 for information regarding these transactions.

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

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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 2015 compared to the third quarter of 2014. Likewise, the phrase “period-to-period” means the nine months ended September 30, 2015 compared to the nine months ended September 30, 2014.

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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,” “could,” “should,” “would,” “will,” “believe,” “may,” “potential” and similar expressions and statements regarding our plans and objectives for future operations are intended to identify forward-looking statements. Although we and our general partner believe that our expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any assurances that such expectations will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions as described in more detail under “Risk Factors” within Part I, Item 1A included in our 2014 Form 10-K and within Part II, Item 1A of this quarterly report. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements. The forward-looking statements in this quarterly report speak only as of the filing date hereof. Except as required by federal and state securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason.

Overview of Business

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

Our integrated midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the U.S., Canada and 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 and in the Gulf of Mexico. Our assets include approximately 49,000 miles of pipelines; 225 MMBbls of storage capacity for NGLs, crude oil, petrochemicals and refined products; and 14 Bcf of natural gas storage capacity.

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

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.

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Significant Recent Developments

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

Second Stage of Aegis Ethane Pipeline Completed

In September 2015, we announced that construction of the Beaumont, Texas to Lake Charles, Louisiana segment of our Aegis Ethane Pipeline (“Aegis”) was complete and ready to deliver ethane to additional Gulf Coast petrochemical facilities. This new 48-mile segment, along with the initial 60-mile segment currently in service, provides reliable ethane supplies to petrochemical facilities between Mont Belvieu, Texas and Lake Charles.

The final 162-mile segment of the Aegis system will extend the pipeline from Lake Charles to the Mississippi River and is expected to be completed by the end of 2015. Aegis is supported by customer commitments in excess of 300 MBPD that ramp up over the next four years. The capacity of the pipeline can be expanded to approximately 400 MBPD with additional pumps.

By combining our 270-mile Aegis pipeline with our existing South Texas midstream infrastructure, we will provide shippers with access to a 500-mile Gulf Coast ethane header system between Corpus Christi, Texas and the Mississippi River in Louisiana.

Sale of Offshore Business

On July 24, 2015, we consummated a sale to Genesis of our Offshore Business, which primarily consisted of our Offshore Pipelines & Services business segment, for approximately \$1.53 billion in cash. Our Offshore Business served drilling and development regions, including deepwater production fields, in the northern Gulf of Mexico offshore Texas, Louisiana, Mississippi and Alabama. As of December 31, 2014, our Offshore Business included approximately 2,350 miles of offshore natural gas and crude oil pipelines and six offshore hub platforms. Our results of operations reflect ownership of the Offshore Business through July 24, 2015.

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

We recorded a non-cash asset impairment charge in June 2015 of approximately \$54.8 million, which reflects the excess of the carrying value of net assets of the Offshore Business at June 30, 2015 over their comparable estimated fair value based on the transaction price. Upon closing of the transaction on July 24, 2015, we recorded a loss on the sale of \$12.6 million.

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

Expansion of Propylene Pipeline System

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

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

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

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

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

Acquisition of Eagle Ford Midstream Assets

In June 2015, we announced the execution of definitive agreements to purchase all of the member interests in EFS Midstream from affiliates of Pioneer and Reliance for approximately \$2.1 billion. The purchase price will be paid in two installments. The first installment of approximately \$1.1 billion was paid at closing on July 8, 2015 and the final installment of approximately \$1.0 billion will be paid no later than the first anniversary of the closing date. The effective date of the acquisition was July 1, 2015. We funded the cash consideration for the first installment using proceeds from the issuance of short-term notes under our commercial paper program and cash on hand.

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

In connection with the agreements to acquire EFS Midstream, we are obligated to spend up to an aggregate of \$270 million on specified midstream gathering assets for Pioneer and Reliance, if requested by these producers, over a ten year period. If constructed, these new assets would be owned by us and be a component of the EFS Midstream asset network

For additional information regarding this acquisition, see Note 8 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Plans to Construct New Crude Oil and Condensate Pipeline from Midland to Houston, Texas

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

Plans to Construct Natural Gas Processing Facility in Delaware Basin

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

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Increase in NGL Loading Capacity at our Houston Ship Channel LPG Export Terminal

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

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

Formation of Panola Pipeline Joint Venture

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

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

Completion of Oiltanking Acquisition

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

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

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

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

On February 23, 2015, we received a Civil Investigative Demand and a related Subpoena Duces Tecum from the Federal Trade Commission (“FTC”) requesting specified information relating to the Oiltanking acquisition and Enterprise’s operations. On April 13, 2015, we received a Civil Investigative Demand issued by the Attorney General of the State of Texas requesting copies of the same information and any correspondence with the FTC. We are in the

process of complying with the requests and are cooperating with the investigations. Based on the limited information that we have at this time, we are unable to predict the outcome of the investigations.

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

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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,	
	2015	2014	2015	2014
Revenues	\$6,307.9	\$12,330.2	\$20,872.9	\$37,760.9
Costs and expenses:				
Operating costs and expenses:				
Cost of sales	4,419.9	10,455.1	15,355.9	32,213.1
Other operating costs and expenses	642.5	633.9	1,834.8	1,865.6
Depreciation, amortization and accretion expense	351.1	322.7	1,082.0	936.5
Net losses (gains) attributable to asset sales and insurance recoveries	12.3	(2.6)	14.7	(99.0)
Non-cash asset impairment charges	26.8	5.7	139.1	18.2
Total operating costs and expenses	5,452.6	11,414.8	18,426.5	34,934.4
General and administrative costs	49.0	50.0	143.2	150.9
Total costs and expenses	5,501.6	11,464.8	18,569.7	35,085.3
Equity in income of unconsolidated affiliates	103.1	72.3	302.5	179.1
Operating income	909.4	937.7	2,605.7	2,854.7
Interest expense	(243.7)	(229.8)	(723.2)	(679.6)
Change in fair value of Liquidity Option Agreement	(4.3)	--	(15.8)	--
Other, net	1.8	(1.0)	2.6	(0.2)
Provision for income taxes	(5.5)	(7.7)	(4.4)	(22.5)
Net income	657.7	699.2	1,864.9	2,152.4
Net income attributable to noncontrolling interests	(8.4)	(8.1)	(28.5)	(24.8)
Net income attributable to limited partners	\$649.3	\$691.1	\$1,836.4	\$2,127.6

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2015	2014	2015	2014
NGL Pipelines & Services:				
Sales of NGLs and related products	\$1,844.9	\$3,603.4	\$5,936.2	\$12,029.8
Midstream services	441.9	423.3	1,293.0	1,197.6
Total	2,286.8	4,026.7	7,229.2	13,227.4
Crude Oil Pipelines & Services:				
Sales of crude oil	2,147.3	5,348.2	7,689.3	16,003.5
Midstream services	175.3	88.9	399.7	264.2
Total	2,322.6	5,437.1	8,089.0	16,267.7
Natural Gas Pipelines & Services:				
Sales of natural gas	455.0	775.5	1,361.2	2,515.7

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Midstream services	254.7	256.4	767.1	761.8
Total	709.7	1,031.9	2,128.3	3,277.5
Petrochemical & Refined Products Services:				
Sales of petrochemicals and refined products	780.5	1,605.4	2,764.2	4,338.2
Midstream services	199.5	186.6	583.4	531.7
Total	980.0	1,792.0	3,347.6	4,869.9
Offshore Pipelines & Services:				
Sales of natural gas	--	--	--	0.2
Sales of crude oil	0.4	2.5	3.2	7.5
Midstream services	8.4	40.0	75.6	110.7
Total	8.8	42.5	78.8	118.4
Total consolidated revenues	\$6,307.9	\$12,330.2	\$20,872.9	\$37,760.9

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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		Normal		Natural				WTI	LLS
	Gas,	Ethane,	Propane,	Butane,	Isobutane,	Gasoline,	PGP,	RGP,	Crude	Crude
	\$/MMBtu	\$/gallon	\$/gallon	\$/gallon	\$/gallon	\$/gallon	\$/pound	\$/pound	Oil,	Oil,
	(1)	(2)	(2)	(2)	(2)	(2)	(3)	(3)	\$/barrel	\$/barrel
2014 by										
quarter:										
1st Quarter	\$ 4.95	\$ 0.34	\$ 1.30	\$ 1.39	\$ 1.42	\$ 2.12	\$ 0.73	\$ 0.61	\$98.68	\$104.43
2nd Quarter	\$ 4.68	\$ 0.29	\$ 1.06	\$ 1.25	\$ 1.30	\$ 2.21	\$ 0.70	\$ 0.57	\$102.99	\$105.55
3rd Quarter	\$ 4.07	\$ 0.24	\$ 1.04	\$ 1.25	\$ 1.28	\$ 2.11	\$ 0.71	\$ 0.58	\$97.21	\$100.94
4th Quarter	\$ 4.04	\$ 0.21	\$ 0.76	\$ 0.98	\$ 0.99	\$ 1.49	\$ 0.69	\$ 0.52	\$73.15	\$76.08
2014 Averages	\$ 4.43	\$ 0.27	\$ 1.04	\$ 1.22	\$ 1.25	\$ 1.98	\$ 0.71	\$ 0.57	\$93.01	\$96.75
2015 by										
quarter:										
1st Quarter	\$ 2.99	\$ 0.19	\$ 0.53	\$ 0.68	\$ 0.68	\$ 1.10	\$ 0.50	\$ 0.37	\$48.63	\$52.83
2nd Quarter	\$ 2.65	\$ 0.18	\$ 0.46	\$ 0.59	\$ 0.60	\$ 1.26	\$ 0.42	\$ 0.29	\$57.94	\$62.97
3rd Quarter	\$ 2.77	\$ 0.19	\$ 0.40	\$ 0.55	\$ 0.55	\$ 0.98	\$ 0.33	\$ 0.21	\$46.43	\$50.17
2015 Averages	\$ 2.80	\$ 0.19	\$ 0.46	\$ 0.61	\$ 0.61	\$ 1.11	\$ 0.42	\$ 0.29	\$51.00	\$55.32

(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 Chemical Market Associates, Inc. ("CMAI"). RGP prices represent weighted-average spot prices for such product as reported by CMAI.

(4) Crude oil prices are based on commercial index prices for WTI as measured on the New York Mercantile Exchange ("NYMEX") and for LLS as reported by Platts.

Fluctuations in our consolidated revenues and cost of sales amounts are explained in large part by changes in energy commodity prices. Energy commodity prices fluctuate for a variety of reasons, including supply and demand imbalances and geopolitical tensions. 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 \$0.45 per gallon in the third quarter of 2015 versus \$0.99 per gallon during the third quarter of 2014. Likewise, the weighted-average indicative market price for NGLs was \$0.50 per gallon during the nine months ended September 30, 2015 compared to \$1.05 per gallon during the same period in 2014.

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

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

commodity hedging activities.

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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 2015 Compared to Third Quarter of 2014. Total revenues for the third quarter of 2015 decreased \$6.02 billion when compared to total revenues for the third quarter of 2014. Revenues from the marketing of NGLs and petrochemicals decreased \$2.2 billion quarter-to-quarter primarily due to lower sales prices. Revenues from the marketing of crude oil, natural gas and refined products decreased \$3.88 billion quarter-to-quarter primarily due to lower sales prices and volumes, which accounted for a \$3.16 billion decrease and a \$725.4 million decrease, respectively. Revenues from midstream services increased a net \$84.6 million quarter-to-quarter primarily due to contributions from recently acquired assets, which were partially offset by a decrease due to the sale of our Offshore Business. Revenues for the third quarter of 2015 include \$57.5 million from the assets we acquired effective October 1, 2014 in connection with the Oiltanking acquisition and \$56.7 million from the assets we acquired effective July 1, 2015 in connection with the EFS Midstream acquisition. Revenues decreased \$31.7 million quarter-to-quarter due to the sale of our Offshore Business effective July 24, 2015.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014. For the nine months ended September 30, 2015, total revenues decreased \$16.89 billion when compared to total revenues for the nine months ended September 30, 2014. Revenues from the marketing of NGLs, petrochemicals and refined products decreased a net \$7.64 billion period-to-period primarily due to lower sales prices, which accounted for an \$8.37 billion decrease, partially offset by higher sales volumes, which accounted for a \$732.8 million increase. Revenues from the marketing of crude oil and natural gas decreased \$9.47 billion period-to-period primarily due to lower sales prices, which accounted for an \$8.62 billion decrease, and lower sales volumes, which accounted for an additional \$853.3 million decrease. Revenues from midstream services increased a net \$252.8 million period-to-period primarily due to the ongoing expansion of our operations. Revenues for the nine months ended September 30, 2015 include \$164.8 million and \$56.7 million from assets we acquired in connection with the Oiltanking and EFS Midstream acquisitions, respectively. Revenues decreased \$35.3 million period-to-period primarily due to the sale of our Offshore Business in July 2015. The remaining \$66.6 million period-to-period increase in revenues is primarily due to recently completed assets such as the ATEX pipeline, portions of the Aegis Ethane Pipeline and expanded crude oil storage capacity at our ECHO terminal.

Operating costs and expenses

Third Quarter of 2015 Compared to Third Quarter of 2014. Total operating costs and expenses for the third quarter of 2015 decreased \$5.96 billion when compared to total operating costs and expenses for the third quarter of 2014. The cost of sales associated with our marketing of NGLs and petrochemicals decreased \$2.23 billion quarter-to-quarter primarily due to lower purchase prices. The cost of sales associated with our marketing of crude oil, natural gas and refined products decreased \$3.79 billion quarter-to-quarter primarily due to lower purchase prices, which accounted for a \$3.13 billion decrease, and lower sales volumes, which accounted for an additional \$660.5 million decrease.

Other operating costs and expenses increased a net \$8.6 million quarter-to-quarter primarily due to the inclusion of assets attributable to the Oiltanking and EFS Midstream acquisitions, which collectively accounted for a \$23.4 million increase, partially offset by \$18.0 million of expense in the third quarter of 2014 related to a settlement with a producer on our San Juan Gathering System. Lastly, other operating costs and expenses decreased \$5.4 million quarter-to-quarter due to the sale of our Offshore Business.

Depreciation, amortization and accretion expense for the third quarter of 2015 increased a net \$28.4 million when compared to the third quarter of 2014 primarily due to the inclusion of assets attributable to the Oiltanking and EFS Midstream acquisitions, which collectively accounted for a \$47.8 million quarter-to-quarter increase, partially offset by the sale of assets attributable to our Offshore Business, which accounted for a \$22.8 million quarter-to-quarter decrease.

We recognized a \$12.6 million loss attributable to the sale of our Offshore Business.

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Operating costs and expenses also include \$26.8 million and \$5.7 million of non-cash asset impairment charges for the third quarters of 2015 and 2014, respectively. 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, 2015 Compared to Nine Months Ended September 30, 2014. For the nine months ended September 30, 2015, total operating costs and expenses decreased \$16.51 billion when compared to the nine months ended September 30, 2014. The cost of sales associated with our marketing of NGLs, petrochemicals and refined products decreased a net \$7.64 billion period-to-period primarily due to lower purchase prices, which accounted for an \$8.33 billion decrease, partially offset by higher sales volumes, which accounted for a \$685.6 million increase. The cost of sales associated with our marketing of crude oil and natural gas decreased \$9.18 billion period-to-period primarily due to lower purchase prices, which accounted for an \$8.4 billion decrease, and lower sales volumes, which accounted for an additional \$779.4 million decrease.

Other operating costs and expenses decreased a net \$30.8 million period-to-period due in part to (i) lower fuel costs, which accounted for a \$57.4 million decrease, (ii) a producer settlement involving our San Juan Gathering System in the third quarter of 2014, which accounted for an \$18.0 million decrease and (iii) the sale of our Offshore Business in July 2015, which primarily accounted for an additional \$8.4 million period-to-period decrease. These decreases were partially offset by the addition of \$35.5 million in operating costs attributable to assets we acquired in the Oiltanking and EFS Midstream acquisitions.

Depreciation, amortization and accretion expense for the nine months ended September 30, 2015 increased \$145.5 million when compared to the same period in 2014 primarily due to the Oiltanking and EFS Midstream acquisitions, which collectively accounted for \$97.5 million of the period-to-period increase. Accretion expense for the nine months ended September 30, 2015 includes \$39.5 million recognized for certain asset retirement obligations of our former Offshore Business. For information regarding our asset retirement obligations, see Note 6 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

For the nine months ended September 30, 2014, we recognized \$95.0 million of gains attributable to the receipt of nonrefundable cash insurance proceeds. These proceeds were attributable to property damage claims we filed in connection with the February 2011 NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility. For the nine months ended September 30, 2015, we recognized a \$12.6 million loss attributable to our sale of the Offshore Business.

Operating costs and expenses also include \$139.1 million and \$18.2 million of non-cash asset impairment charges for the nine months ended September 30, 2015 and 2014, respectively. As noted previously, we recorded a \$54.8 million non-cash asset impairment charge for the nine months ended September 30, 2015 in connection with the sale of our Offshore Business. The remainder of our non-cash asset impairment charges for the nine months ended September 30, 2015 primarily relate to natural gas processing assets in southern Louisiana, certain marine vessels and the abandonment of certain crude oil and natural gas pipeline assets in Texas.

General and administrative costs

General and administrative costs for the third quarter of 2015 decreased \$1.0 million when compared to the third quarter of 2014. For the nine months ended September 30, 2015, general and administrative costs decreased \$7.7 million when compared to the same period in 2014 primarily due to costs we incurred during the first quarter of 2014 for the settlement of litigation associated with our merger in 2010 with Enterprise GP Holdings L.P.

Equity in income of unconsolidated affiliates

Equity income for the three and nine months ended September 30, 2015 increased \$30.8 million and \$123.4 million, respectively, when compared to the same periods in 2014. These increases are primarily due to increased earnings from our investments in crude oil and NGL pipeline joint ventures.

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Interest expense for the three and nine months ended September 30, 2015 increased \$13.9 million and \$43.6 million, respectively, when compared to the same periods in 2014. The following table presents the components of our consolidated interest expense for the periods indicated (dollars in millions):

	For the Three Months Ended September 30, 2015		For the Nine Months Ended September 30, 2014	
Interest charged on debt principal outstanding	\$270.6	\$240.3	\$793.7	\$713.6
Impact of interest rate hedging program, including related amortization	3.2	1.6	12.1	4.6
Interest costs capitalized in connection with construction projects (1)	(40.3)	(17.2)	(105.6)	(53.4)
Other (2)	10.2	5.1	23.0	14.8
Total	\$243.7	\$229.8	\$723.2	\$679.6

(1) Capitalized interest amounts become part of the historical cost of an asset and are charged to earnings (as a component of depreciation expense) ratably over the estimated useful life of the asset once the asset enters its intended service. Capitalized interest amounts fluctuate based on the timing of when projects are placed into service, our capital spending levels and the interest rates charged on borrowings.

(2) Primarily reflects facility commitment fees charged in connection with our revolving credit facilities and amortization of debt issuance costs.

Interest charged on debt principal outstanding, which is the primary driver of interest expense, increased a net \$30.3 million quarter-to-quarter primarily due to increased debt principal amounts outstanding during the third quarter of 2015, which accounted for a \$46.8 million increase, partially offset by the effect of lower overall interest rates in the third quarter of 2015, which accounted for a \$16.5 million decrease. Our weighted-average debt principal balance for the third quarter of 2015 was \$22.45 billion compared to \$18.77 billion for the third quarter of 2014. In general, our debt principal balances have increased over time due to the partial debt financing of our capital spending program. For a discussion of our consolidated debt obligations and capital spending program, see “Liquidity and Capital Resources” within this Part I, Item 2.

For the nine months ended September 30, 2015, interest charged on debt principal outstanding increased a net \$80.1 million period-to-period primarily due to increased debt principal amounts outstanding during the nine months ended September 30, 2015, which accounted for a \$139.3 million increase, partially offset by the effect of lower overall interest rates in the nine months ended September 30, 2015, which accounted for a \$59.2 million decrease. Our weighted-average debt principal balance for the nine months ended September 30, 2015 was \$22.08 billion compared to \$18.29 billion for the same period in 2014.

Change in fair value of Liquidity Option Agreement

Results for the three and nine months ended September 30, 2015 include \$4.3 million and \$15.8 million, respectively, of expense we recorded to recognize changes in the fair value of the Liquidity Option Agreement. For information regarding the Liquidity Option Agreement, see Note 15 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Income taxes

Our provision for income taxes for the three and nine months ended September 30, 2015 decreased \$2.2 million and \$18.1 million, respectively, when compared to the same periods in 2014. These decreases are primarily due to changes in our accruals for state tax obligations under the Revised Texas Franchise Tax (or “Texas Margin Tax”). In

June 2015, the State of Texas enacted certain changes to the Texas Margin Tax, which lowered the tax rate.

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Business Segment Highlights

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2015	2014	2015	2014
NGL Pipelines & Services	\$695.5	\$711.5	\$2,041.3	\$2,172.4
Crude Oil Pipelines & Services	254.6	190.8	704.2	534.5
Natural Gas Pipelines & Services	192.4	195.4	588.3	618.8
Petrochemical & Refined Products Services	191.5	190.3	547.4	482.4
Offshore Pipelines & Services	7.1	47.1	97.5	120.0
Total	\$1,341.1	\$1,335.1	\$3,978.7	\$3,928.1

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

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

NGL Pipelines & Services

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2015	2014	2015	2014
Segment gross operating margin:				
Natural gas processing and related NGL marketing activities	\$203.2	\$290.5	\$663.7	\$905.4
NGL pipelines and related storage	366.1	277.7	1,006.0	828.9
NGL fractionation	126.2	143.3	371.6	438.1
Total	\$695.5	\$711.5	\$2,041.3	\$2,172.4
Selected volumetric data:				
NGL transportation volumes (MBPD)	3,156	2,866	2,942	2,862
NGL fractionation volumes (MBPD)	837	823	819	820
Equity NGL production (MBPD) (1)	129	103	129	125
Fee-based natural gas processing (MMcf/d) (2)	5,035	4,958	4,911	4,872

(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 2015 Compared to Third Quarter of 2014. Gross operating margin from natural gas processing and related NGL marketing activities for the third quarter of 2015 decreased \$87.3 million when compared to the third quarter of 2014. Gross operating margin from our natural gas processing plants decreased \$99.0 million quarter-to-quarter primarily due to lower processing margins. In addition, gross operating margin from our NGL marketing activities for the third quarter of 2015 increased a net \$11.7 million when compared to the third quarter of 2014 primarily due to higher sales volumes, which accounted for a \$29.9 million increase, partially offset by a \$14.4 million decrease due to lower sales margins.

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Year-to-Date September 2015 Compared to Year-to-Date September 2014. For the nine months ended September 30, 2015, gross operating margin from natural gas processing and related NGL marketing activities decreased \$241.7 million when compared to the same period in 2014. Gross operating margin from our natural gas processing plants decreased \$205.9 million period-to-period primarily due to lower processing margins. In addition, gross operating margin from our NGL marketing activities for the nine months ended September 30, 2015 decreased a net \$35.8 million when compared to the nine months ended September 30, 2014 primarily due to lower sales margins, which accounted for a \$149.7 million decrease, partially offset by a \$119.8 million increase due to higher sales volumes. During the nine months ended September 30, 2015, a higher percentage of volume in the LPG export business was associated with long-term, fee-based marketing contracts rather than spot business, which is typically contracted at higher margins and was prevalent in the nine months ended September 30, 2014.

NGL pipelines and related storage

Third Quarter of 2015 Compared to Third Quarter of 2014. Gross operating margin from NGL pipelines and related storage assets for the third quarter of 2015 increased \$88.4 million when compared to the third quarter of 2014. Gross operating margin from our Houston Ship Channel marine terminal and related pipeline increased \$32.7 million quarter-to-quarter, of which \$17.3 million of the increase is attributable to the addition of Oiltanking's operations in October 2014, and \$15.4 million to a combined 167 MBPD increase in volumes. In April 2015, we completed an expansion project at our Houston Ship Channel marine terminal that increased our ability to load cargos of LPGs from 7.5 MMBbls per month to approximately 9.0 MMBbls per month. In contrast, our LPG export terminal experienced a brief outage during the third quarter of 2014 for activities related to the terminal expansion project and maintenance, which reduced volumes during this period.

Gross operating margin from the Chaparral Pipeline, Mid-America Pipeline System, Seminole Pipeline and related terminals increased \$24.4 million quarter-to-quarter primarily due to higher transportation tariffs and other fees, which accounted for a \$21.9 million quarter-to-quarter increase in gross operating margin, and a \$2.9 million quarter-to-quarter decrease in operating expenses. Gross operating margin from our investments in the Front Range Pipeline, Texas Express Pipeline and Texas Express Gathering System for the third quarter of 2015 increased \$4.2 million primarily due to a combined 20 MBPD increase in transportation volumes (net to our interest) when compared to the third quarter of 2014. Gross operating margin from our ATEX and Aegis Ethane Pipelines increased \$7.9 million quarter-to-quarter primarily due to a combined 42 MBPD increase in transportation volumes. The first segment of our Aegis Ethane Pipeline was completed in September 2014, with the second segment placed into service in September 2015.

Gross operating margin from our South Texas NGL Pipeline System increased \$6.4 million quarter-to-quarter attributable to a 68 MBPD increase in transportation volumes, which was primarily due to increased production from the Eagle Ford Shale. Lastly, gross operating margin from our Tri-States NGL Pipeline increased \$6.0 million quarter-to-quarter due to higher tariffs, which accounted for a \$3.8 million increase, a \$1.1 million increase due to higher transportation volumes of 3 MBPD (net to our interest), and a \$1.1 million decrease in operating expenses.

Year-to-Date September 2015 Compared to Year-to-Date September 2014. For the nine months ended September 30, 2015, gross operating margin from NGL pipelines and related storage assets increased \$177.1 million when compared to the same period in 2014. Gross operating margin from our Houston Ship Channel marine terminal and related pipeline increased \$74.7 million period-to-period, of which \$45.8 million of the increase is attributable to our acquisition of Oiltanking and \$28.9 million due to a combined 109 MBPD increase in volumes.

For the nine months ended September 30, 2015, gross operating margin from the Chaparral Pipeline, Mid-America Pipeline System, Seminole Pipeline and related terminals increased \$43.2 million when compared to the same period in 2014. Higher transportation tariffs and other fees, which accounted for a \$57.5 million period-to-period increase in

gross operating margin, and a \$29.2 million period-to-period decrease in operating expenses were partially offset by a \$43.5 million decrease in gross operating margin attributable to lower transportation volumes. Transportation volumes on these three pipelines for the nine months ended September 30, 2015 decreased a combined 101 MBPD due in part to lower recoveries of ethane when compared to the same period in 2014. Lower recoveries of ethane at upstream natural gas processing plants served by these pipelines resulted in lower volumes of ethane available for transportation.

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For the nine months ended September 30, 2015, gross operating margin from our investments in the Front Range Pipeline, Texas Express Pipeline and Texas Express Gathering System increased \$15.4 million primarily due to a combined 31 MBPD increase in transportation volumes (net to our interest) when compared to the same period in 2014. Gross operating margin from our ATEX and Aegis Ethane Pipelines increased \$12.1 million period-to-period primarily due to a combined 43 MBPD increase in transportation volumes. Gross operating margin from our South Texas NGL Pipeline System increased \$12.6 million period-to-period primarily due to higher transportation volumes of 24 MBPD. Lastly, gross operating margin from our NGL pipelines and related storage assets increased \$14.5 million period-to-period as a result of net operational measurement losses during the nine months ended September 30, 2014 that did not reoccur in the same period in 2015.

NGL fractionation

Third Quarter of 2015 Compared to Third Quarter of 2014. Gross operating margin from NGL fractionation for the third quarter of 2015 decreased \$17.1 million when compared to the third quarter of 2014. This decrease in gross operating margin is primarily due to a combined \$18.6 million decrease in product blending and other fee revenues at our Mont Belvieu NGL fractionation facility. Certain of these revenues are influenced by energy commodity prices, which have generally declined since the beginning of 2014.

Year-to-Date September 2015 Compared to Year-to-Date September 2014. For the nine months ended September 30, 2015, gross operating margin from NGL fractionation decreased \$66.5 million when compared to the same period in 2014. Gross operating margin from our Mont Belvieu NGL fractionators decreased \$56.2 million period-to-period primarily due to lower product blending and other fee revenues. Gross operating margin from our Hobbs NGL fractionator in Gaines County, Texas decreased \$7.0 million period-to-period primarily due to lower fractionation volumes of 12 MBPD. Gross operating margin from our Norco NGL fractionator in Louisiana decreased a net \$4.7 million period-to-period primarily due to lower revenues from product blending and percent-of-liquids contracts attributable to lower energy commodity prices, which accounted for an \$11.8 million quarter-to-quarter decrease, partially offset by a \$7.2 million increase due to higher fractionation volumes of 13 MBPD.

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, 2015		For the Nine Months Ended September 30, 2014	
Segment gross operating margin	\$254.6	\$190.8	\$704.2	\$534.5
Selected volumetric data:				
Crude oil transportation volumes (MBPD)	1,535	1,266	1,507	1,274

Third Quarter of 2015 Compared to Third Quarter of 2014. Gross operating margin from our Crude Oil Pipelines & Services segment for the third quarter of 2015 increased \$63.8 million when compared to the third quarter of 2014. The EFS Midstream system, which we acquired effective July 1, 2015, contributed \$40.7 million of gross operating margin and 66 MBPD of throughput volumes for the third quarter of 2015. Gross operating margin from crude oil terminaling services at our Houston Ship Channel facility, which we acquired in October 2014 in connection with the Oiltanking acquisition, contributed \$35.6 million to our results in the third quarter of 2015. Gross operating margin from our equity investment in the Seaway Pipeline increased \$16.6 million quarter-to-quarter primarily due to contributions from the Seaway Loop, which commenced operations in December 2014. Seaway's transportation

volumes increased 161 MBPD quarter-to-quarter (net to our interest) primarily due to an increase in long-haul volumes. Gross operating margin from our West Texas System increased \$9.8 million quarter-to-quarter primarily due to higher volumes of 38 MBPD during the third quarter of 2015 when compared to the third quarter of 2014.

Gross operating margin from our South Texas Crude Oil Pipeline System decreased \$18.2 million quarter-to-quarter primarily due to a 32 MBPD decrease in volumes, which accounted for a \$12.1 million decrease, and a \$10.6 million decrease from the sale of excess crude oil volumes obtained through pipeline tariff allowances. The decrease in crude oil transportation volumes was primarily due to lower production volumes from legacy fields in South Texas and the abandonment of certain segments of pipeline. The decrease in revenues from the sale of excess crude oil volumes is attributable to the decline in crude oil prices since the third quarter of 2014.

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Gross operating margin from our crude oil marketing and related trucking activities decreased \$23.0 million quarter-to-quarter primarily due to lower crude oil sales margins.

Year-to-Date September 2015 Compared to Year-to-Date September 2014. For the nine months ended September 30, 2015, gross operating margin from our Crude Oil Pipelines & Services segment increased \$169.7 million when compared to the same period in 2014. Gross operating margin from crude oil terminaling services at our Houston Ship Channel facility contributed \$97.6 million during the nine months ended September 30, 2015. In addition, gross operating margin from our equity investment in the Seaway Pipeline increased \$67.2 million period-to-period primarily due to contributions from the Seaway Loop. Seaway's transportation volumes increased 117 MBPD period-to-period (net to our interest) primarily due to an increase in long-haul volumes. As noted previously, the EFS Midstream system contributed \$40.7 million of gross operating margin to our results along with 66 MBPD of throughput volumes. Gross operating margin from our West Texas System increased \$15.7 million period-to-period primarily due to a 33 MBPD increase in volumes during the 2015 period. Gross operating margin from our equity investment in the Eagle Ford Crude Oil Pipeline System increased \$12.9 million period-to-period primarily due to a 48 MBPD increase in volumes (net to our interest).

Gross operating margin from our South Texas Crude Oil Pipeline System decreased \$40.5 million period-to-period primarily due to a \$27.2 million decrease from the sale of excess crude oil volumes obtained through pipeline tariff allowances and a 14 MBPD decrease in volumes, which accounted for an additional \$16.1 million decrease.

Gross operating margin from our crude oil marketing and related trucking activities decreased \$32.5 million period-to-period primarily due to lower crude oil sales margins.

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,	
	2015	2014	2015	2014
Segment gross operating margin	\$192.4	\$195.4	\$588.3	\$618.8
Selected volumetric data:				
Natural gas transportation volumes (BBtus/d)	12,387	12,486	12,459	12,541

Third Quarter of 2015 Compared to Third Quarter of 2014. Gross operating margin from our Natural Gas Pipelines & Services segment for the third quarter of 2015 decreased \$3.0 million when compared to the third quarter of 2014. Gross operating margin from our Piceance Basin and Haynesville Gathering Systems decreased \$4.9 million quarter-to-quarter primarily due to a combined 258 BBtus/d decrease in gathering volumes, which accounted for a \$2.7 million decrease, and lower gathering fees, which accounted for an additional \$1.8 million decrease. Gross operating margin from our Texas Intrastate System decreased a net \$2.2 million quarter-to-quarter primarily due to a \$3.5 million increase in operating expenses, partially offset by a 224 BBtus/d increase in transportation volumes, which accounted for a \$1.5 million increase. Gross operating margin from our Acadian Gas System decreased \$2.0 million quarter-to-quarter primarily due to a decrease in fees.

Gross operating margin from our San Juan Gathering System increased a net \$4.9 million quarter-to-quarter primarily due to a \$15.6 million decrease in operating expenses. We recorded \$18.0 million of expense during the third quarter of 2014 for the settlement of a contract dispute with a producer. The quarter-to-quarter decrease in operating expenses

was partially offset by the impact of lower energy commodity prices in 2015. Lower gathering fees, which are indexed to natural gas prices, resulted in a \$4.1 million quarter-to-quarter decrease in gross operating margin. Likewise, condensate and natural gas sales margins on our San Juan Gathering System decreased a combined \$5.7 million quarter-to-quarter primarily due to lower commodity prices.

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Year-to-Date September 2015 Compared to Year-to-Date September 2014. For the nine months ended September 30, 2015, gross operating margin from our Natural Gas Pipelines & Services segment decreased \$30.5 million when compared to the same period in 2014. Gross operating margin from our Piceance Basin and Haynesville Gathering Systems decreased \$13.7 million period-to-period primarily due to a combined 261 BBtus/d decrease in gathering volumes, which accounted for a \$9.7 million decrease, and lower gathering fees, which accounted for an additional \$3.9 million decrease. Gross operating margin from our Texas Intrastate System decreased \$15.5 million period-to-period primarily due to an increase in maintenance and other operating expenses. Gross operating margin from our San Juan Gathering System decreased a net \$14.5 million period-to-period primarily due to a \$15.8 million decrease in gathering fees, which are indexed to natural gas prices, and a \$17.3 million decrease in condensate and natural gas sales primarily resulting from lower sales prices, partially offset by a \$21.1 million decrease in operating expenses.

Gross operating margin from our Jonah Gathering System increased a net \$12.4 million period-to-period primarily due to higher volumes of 99 BBtus/d, which accounted for a \$7.3 million increase, and higher gathering fees, which accounted for an additional \$9.1 million increase, partially offset by a \$2.8 million decrease in condensate sales.

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, 2015		For the Nine Months Ended September 30, 2014	
Segment gross operating margin:				
Propylene fractionation and related activities	\$46.7	\$65.4	\$145.3	\$156.4
Butane isomerization and related operations	18.1	11.6	44.1	65.8
Octane enhancement and related plant operations	57.5	48.2	126.8	94.7
Refined products pipelines and related activities	53.0	48.1	183.3	114.2
Marine transportation and other	16.2	17.0	47.9	51.3
Total	\$191.5	\$190.3	\$547.4	\$482.4
Selected volumetric data:				
Propylene fractionation volumes (MBPD)	72	73	71	72
Butane isomerization volumes (MBPD)	108	95	90	93
Standalone DIB processing volumes (MBPD)	89	86	79	81
Octane additive and related plant production volumes (MBPD)	20	20	17	15
Transportation volumes, primarily refined products and petrochemicals (MBPD)	904	809	862	782

Propylene fractionation and related activities

Third Quarter of 2015 Compared to Third Quarter of 2014. Gross operating margin from propylene fractionation and related activities for the third quarter of 2015 decreased \$18.7 million when compared to the third quarter of 2014. Gross operating margin from our Mont Belvieu propylene fractionation plants decreased \$19.1 million quarter-to-quarter primarily due to an \$8.3 million decrease in propylene sales and an \$8.0 million increase in maintenance and other operating expenses. The decrease in propylene sales is primarily due to lower sales margins, which accounted for a \$5.5 million decrease, and lower sales volumes, which accounted for an additional \$2.8 million decrease.

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Year-to-Date September 2015 Compared to Year-to-Date September 2014. For the nine months ended September 30, 2015, gross operating margin from propylene fractionation and related activities decreased \$11.1 million when compared to the same period in 2014. Gross operating margin from our Mont Belvieu propylene fractionation plants decreased \$22.1 million period-to-period. Operating expenses at these plants increased \$29.0 million period-to-period primarily due to maintenance activities we completed during the nine months ended September 30, 2015, partially offset by a \$6.9 million increase in gross operating margin period-to-period primarily due to higher propylene sales margins. Gross operating margin from our propylene rail terminal at Mont Belvieu increased \$4.0 million period-to-period primarily due to higher volumes, which accounted for a \$1.3 million increase, and higher fees, which accounted for an additional \$2.5 million increase. Gross operating margin from the remainder of this business increased \$7.0 million period-to-period primarily due to operational measurement losses in the 2014 period that did not reoccur in the 2015 period.

Butane isomerization and deisobutanizer operations

Third Quarter of 2015 Compared to Third Quarter of 2014. Gross operating margin from butane isomerization and deisobutanizer (“DIB”) operations for the third quarter of 2015 increased \$6.5 million when compared to the third quarter of 2014. Gross operating margin from our Mont Belvieu isomerization facility increased \$6.8 million quarter-to-quarter primarily due to a \$17.5 million decrease in operating expenses, partially offset by a \$10.1 million decrease in by-product sales attributable to lower sales prices. The quarter-to-quarter decrease in operating expenses is primarily due to higher maintenance costs we incurred during the third quarter of 2014 involving these assets.

Year-to-Date September 2015 Compared to Year-to-Date September 2014. For the nine months ended September 30, 2015, gross operating margin from our butane isomerization and DIB operations decreased \$21.7 million when compared to the same period in 2014 primarily due to lower by-product sales and isomerization revenues. By-product sales revenues decreased \$32.4 million period-to-period primarily due to lower sales prices. Isomerization revenues decreased \$10.5 million period-to-period, of which an \$8.2 million decrease is due to lower fees and a \$2.3 million decrease is due to lower isomerization volumes of 3 MBPD. Maintenance and other operating expenses at our isomerization facility decreased \$21.8 million period-to-period.

Octane enhancement and HPIB plant operations

Third Quarter of 2015 Compared to Third Quarter of 2014. Gross operating margin from our octane enhancement facility and high purity isobutylene (“HPIB”) plant for the third quarter of 2015 increased \$9.3 million when compared to the third quarter of 2014 primarily due to higher sales margins.

Year-to-Date September 2015 Compared to Year-to-Date September 2014. For the nine months ended September 30, 2015, gross operating margin from these operations increased \$32.1 million when compared to the same period in 2014. The period-to-period increase in gross operating margin is primarily due to higher sales volumes during the nine months ended September 30, 2015 when compared to the same period in 2014.

Refined products pipelines and related activities

Third Quarter of 2015 Compared to Third Quarter of 2014. Gross operating margin from refined products pipelines and related marketing activities for the third quarter of 2015 increased \$4.9 million when compared to the third quarter of 2014. Contributions from recently acquired and reactivated assets were partially offset by a \$12.5 million increase in expenses for pipeline integrity and related projects on our TE Products Pipeline and related refined products terminals. Gross operating margin for the third quarter of 2015 includes \$6.0 million and \$8.4 million from refined products terminaling services provided at our Beaumont Marine West terminal and Houston Ship Channel terminal, respectively. We acquired these terminals in October 2014 in connection with the Oiltanking acquisition. Gross

operating margin from our Beaumont Refined Products Export terminal, which we reactivated in May 2014, increased \$2.1 million quarter-to-quarter attributable to higher volumes of 57 MBPD.

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Year-to-Date September 2015 Compared to Year-to-Date September 2014. For the nine months ended September 30, 2015, gross operating margin from refined products pipelines and related marketing activities increased \$69.1 million when compared to the same period in 2014. Gross operating margin from our TE Products Pipeline and related refined products terminals increased \$12.3 million period-to-period primarily due to higher tariffs and other fees. Overall, transportation volumes on the TE Products Pipeline increased a net 36 MBPD period-to-period primarily due to higher refined products and petrochemical transportation volumes. Gross operating margin from our Beaumont Refined Products Export terminal increased \$14.6 million period-to-period on higher volumes of 47 MBPD. For the nine months ended September 30, 2015, gross operating margin includes \$21.4 million and \$18.8 million from refined products terminaling services provided at our Beaumont Marine West terminal and Houston Ship Channel terminal, respectively.

Offshore Pipelines & Services

As discussed in “Significant Recent Developments,” we sold our Offshore Business to Genesis 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, 2014	
Segment gross operating margin	\$7.1	\$47.1	\$97.5	\$120.0
Selected volumetric data:				
Natural gas transportation volumes (BBtus/d)	565	683	587	621
Crude oil transportation volumes (MBPD)	344	335	357	329
Platform natural gas processing (MMcf/d)	82	152	101	150
Platform crude oil processing (MBPD)	9	16	13	14

Gross operating margin from our Offshore Pipelines & Services segment for the third quarter and first nine months of 2015 decreased \$40.0 million and \$22.5 million, respectively, when compared to the same periods of 2014 due to the sale of our Offshore Business in July 2015.

Liquidity and Capital Resources

At September 30, 2015, we had \$4.71 billion of consolidated liquidity, which was comprised of \$80.5 million of unrestricted cash on hand and \$4.63 billion of available borrowing capacity under EPO’s revolving credit facilities. Based on current market conditions (as of the filing date of this quarterly report), we believe we will have sufficient liquidity, cash flow from operations and access to capital markets to fund our capital expenditures and working capital needs for the reasonably foreseeable future.

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

Consolidated Debt

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

		Scheduled Maturities of Debt					
		Remainder					
		of					
	Total	2015	2016	2017	2018	2019	Thereafter
Commercial Paper Notes	\$869.5	\$869.5	\$--	\$--	\$--	\$--	\$--
Senior Notes	20,150.0	--	750.0	800.0	1,100.0	1,500.0	16,000.0
Junior Subordinated Notes	1,478.3	--	--	--	--	--	1,478.3
Total	\$22,497.8	\$869.5	\$750.0	\$800.0	\$1,100.0	\$1,500.0	\$17,478.3

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

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Issuance of \$2.5 Billion of Senior Notes in May 2015

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

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

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

Partial Retirement of Junior Subordinated Notes During Third Quarter of 2015

During the third quarter of 2015, EPO retired \$28.1 million of its Junior Subordinated Notes A and \$26.3 million of its Junior Subordinated Notes C with cash from operations. A \$1.4 million gain on the extinguishment of these debt obligations is included in “Other, net” on our Unaudited Condensed Statements of Consolidated Operations.

364-Day Credit Agreement

In September 2015, EPO amended its 364-Day Credit Agreement to extend its maturity date to September 2016. 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 2017. 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 2014 Form 10-K.

Multi-Year Revolving Credit Facility

In September 2015, EPO amended its Multi-Year Revolving Credit Facility to increase its borrowing capacity from \$3.5 billion to \$4.0 billion and extend its maturity date from June 2018 to September 2020. The amended agreement also provides that EPO may increase its borrowing capacity to \$4.5 billion by allowing existing lenders under the facility to increase their respective commitments or by adding one or more new lenders to the agreement. The remaining terms of the Multi-Year Revolving Credit Facility, as amended, remain materially the same as those reported for the Multi-Year Revolving Credit Facility in our 2014 Form 10-K.

Issuance of Common Units

The following information describes significant transactions that affected our partners’ equity accounts during the nine months ended September 30, 2015:

Completion of Oiltanking Acquisition

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

additional information regarding the Oiltanking acquisition.

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At-The-Market (“ATM”) Program

On July 1, 2015, we filed a registration statement with the SEC covering the issuance of up to \$1.92 billion of our common units in amounts, at prices and on terms to be determined by market conditions and other factors at the time of such offerings. Pursuant to this 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 August 3, 2015 and replaced our prior registration statement with respect to the ATM program, which was filed with the SEC in October 2013 and covered the issuance of up to \$1.25 billion of our common units. After taking into account the aggregate sales price of common units sold under our ATM program through September 30, 2015 as described below, we now have the capacity to issue additional common units under our ATM program up to an aggregate sales price of \$1.92 billion.

During the nine months ended September 30, 2015, we issued 23,258,453 common units under the ATM program for aggregate gross proceeds of \$767.1 million. This includes 3,225,057 common units sold in March 2015 to a privately held affiliate of EPCO, which generated gross proceeds of \$100 million. After taking into account applicable costs, our transactions under the ATM program resulted in aggregate net cash proceeds of \$759.7 million for the nine months ended September 30, 2015.

DRIP and EUPP

We also have registration statements on file with the SEC collectively authorizing the issuance of up to 140,000,000 of our common units in connection with a distribution reinvestment plan (“DRIP”). We issued a total of 7,965,318 common units under our DRIP during the nine months ended September 30, 2015, which generated net cash proceeds of \$242.8 million. After taking into account the number of common units issued under the DRIP through September 30, 2015, we have the capacity to issue an additional 19,516,031 common units under this plan.

During the nine months ended September 30, 2015, affiliates of privately held EPCO reinvested \$50 million, resulting in the issuance of 1,543,581 common units under our DRIP (this amount being a component of the total common units issued under the DRIP for the nine months ended September 30, 2015). These same affiliates purchased an additional \$50 million of our common units under the DRIP in November 2015.

In addition to the DRIP, we have registration statements on file with the SEC authorizing the issuance of up to 8,000,000 of our common units in connection with our employee unit purchase plan (“EUPP”). We issued 285,997 common units under our EUPP during the nine months ended September 30, 2015, 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, 2015, we may issue an additional 6,867,071 common units under this plan.

Use of Proceeds

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

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

Credit Ratings

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

non-solicited ratings of BBB+ and F-2 for EPO's long-term senior unsecured debt securities and short-term senior unsecured debt securities, respectively.

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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,	
	2015	2014
Net cash flows provided by operating activities	\$2,591.2	\$2,704.4
Cash used in investing activities	2,308.2	2,268.1
Cash provided by (used in) financing activities	(276.9)	568.4

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

Comparison of Nine Months Ended September 30, 2015 with Nine Months Ended September 30, 2014

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

Operating Activities

Net cash flows provided by operating activities for the nine months ended September 30, 2015 decreased \$113.2 million when compared to the same period in 2014. The decrease in cash provided by operating activities was primarily due to:

§ a \$192.1 million period-to-period decrease in cash primarily due to the timing of cash receipts and payments related to operations; and

§ a \$22.8 million decrease in cash attributable to lower partnership income in the nine months ended September 30, 2015 compared to the same period in 2014 (after adjusting our \$287.5 million period-to-period decrease in net income for changes in the non-cash items identified on our Unaudited Condensed Statements of Consolidated Cash Flows); partially offset by

§ a \$101.7 million period-to-period increase in cash distributions received from unconsolidated affiliates primarily due to improved results from our investments in crude oil and NGL pipeline joint ventures.

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

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Investing Activities

Cash used in investing activities for the nine months ended September 30, 2015 increased \$40.1 million when compared to the same period in 2014 primarily due to:

§ a net \$1.05 billion cash outflow in July 2015 in connection with the acquisition of EFS Midstream (see “Significant Recent Developments – Acquisition of Eagle Ford Midstream Assets” under this Part I, Item 2);

§ a \$759.6 million period-to-period increase in capital spending for consolidated property, plant and equipment, net of contributions in aid of construction costs;

§ a \$105.2 million period-to-period change in restricted cash requirements; partially offset by

§ a \$1.42 billion period-to-period increase in proceeds from asset sales and insurance recoveries primarily due to the sale of our Offshore Business in July 2015, which generated proceeds of \$1.53 billion (see “Significant Recent Developments – Sale of Offshore Business” under this Part I, Item 2), partially offset by a \$95.0 million period-to-period decrease in cash proceeds from insurance recoveries (see Note 16 of the Notes to Unaudited Condensed Consolidated Financial Statements under Part I, Item 1 of this quarterly report for additional information regarding proceeds from insurance recoveries); and

§ a \$452.6 million period-to-period decrease in cash contributions to our unconsolidated affiliates primarily due to the completion of construction of the Front Range Pipeline and the Seaway Loop, partially offset by increased investments in the Eagle Ford Crude Oil Pipeline System.

Financing Activities

Our net cash used in financing activities for the nine months ended September 30, 2015 was \$276.9 million compared to net cash provided by financing activities of \$568.4 million for the same period in 2014. The \$845.3 million period-to-period change in cash flow from financing activities was primarily due to:

§ a \$1.34 billion period-to-period decrease in net borrowings under our consolidated debt agreements. EPO issued \$2.5 billion and repaid \$1.48 billion in principal amount of debt obligations during the nine months ended September 30, 2015 compared to the issuance of \$2.0 billion and repayment of \$500.0 million in principal amount of senior notes during the same period in 2014. In addition, net repayments under EPO’s commercial paper program were \$40.8 million during the nine months ended September 30, 2015 compared to net issuances of \$814.6 million during the same period in 2014; and

§ a \$236.9 million increase in cash distributions paid to limited partners during the nine months ended September 30, 2015 when compared to the same period in 2014. The increase in cash distributions is due to increases in both the number of distribution-bearing common units outstanding and the quarterly cash distribution rates per unit; partially offset by

§ a \$706.5 million period-to-period increase in net cash proceeds from the issuance of common units. We issued an aggregate 31,509,768 common units in connection with our ATM program, DRIP and EUPP during the nine months ended September 30, 2015, which generated \$1.01 billion of net cash proceeds. This compares to an aggregate 8,946,238 common units we issued in connection with our ATM program, DRIP and EUPP during the same period in 2014, which collectively generated \$304.9 million of net cash proceeds.

Cash Distributions to Limited Partners

Our partnership agreement requires us to make quarterly distributions to our unitholders of all available cash, after any cash reserves established by Enterprise GP in its sole discretion. Cash reserves include those for the proper conduct of

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

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

	Distribution Per Common Unit	Record Date	Payment Date
2014:			
1st Quarter	\$ 0.3550	4/30/2014	5/7/2014
2nd Quarter	\$ 0.3600	7/31/2014	8/7/2014
3rd Quarter	\$ 0.3650	10/31/2014	11/7/2014
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

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,	
	2015	2014	2015	2014
Net income attributable to limited partners (1)	\$649.3	\$691.1	\$1,836.4	\$2,127.6
Adjustments to GAAP net income attributable to limited partners to derive non-GAAP distributable cash flow:				
Add depreciation, amortization and accretion expenses	372.8	341.4	1,147.7	992.4
Add non-cash asset impairment charges	26.8	5.7	139.1	18.2
Add losses or subtract gains attributable to asset sales and insurance recoveries, net	12.3	(2.6)	14.7	(99.0)
Add cash proceeds from asset sales and insurance recoveries (2)	1,531.4	8.3	1,537.3	121.5
Add changes in fair value of Liquidity Option Agreement (3)	4.3	--	15.8	--
Add cash distributions received from unconsolidated affiliates (4)	96.9	103.6	362.4	260.7
Subtract equity in income of unconsolidated affiliates (4)	(103.1)	(72.3)	(302.5)	(179.1)
Subtract sustaining capital expenditures (5)	(84.3)	(106.8)	(195.8)	(262.0)
Add deferred income tax expense or subtract benefit	(1.6)	2.0	(13.3)	2.6
Other, net	(3.5)	4.4	(23.3)	32.7
Distributable cash flow	\$2,501.3	\$974.8	\$4,518.5	\$3,015.6
Total cash distributions paid to limited partners with respect to period	\$760.7	\$691.1	\$2,246.4	\$2,002.6
Cash distributions per unit declared by Enterprise GP with respect to period	\$0.385	\$0.365	\$1.14	\$1.08
Total distributable cash flow retained by partnership with respect to period (6)	\$1,740.6	\$283.7	\$2,272.1	\$1,013.0
Distribution coverage ratio (7)	3.3x	1.4x	2.0x	1.5x

- (1) For a discussion of significant changes in our comparative income statement amounts underlying net income attributable to limited partners, along with the primary drivers of such changes, see “Consolidated Income Statements Highlights” within this Part I, Item 2.
- (2) For a discussion of significant changes in cash proceeds from asset sales and insurance recoveries as presented in the investing activities section of our Unaudited Condensed Statements of Consolidated Cash Flows, see “Cash Flows from Operating, Investing and Financing Activities” within this Part I, Item 2.
- (3) For information regarding our Liquidity Option Agreement, see Note 15 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.
- (4) For information regarding our unconsolidated affiliates, see Note 7 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.
- (5) For purposes of this calculation, sustaining capital expenditures for each period include the impact of accruals.
- (6) At the sole discretion of Enterprise GP, cash retained by the partnership with respect to each of these periods 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.
- (7) 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.

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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 expires at the end of calendar year 2015; therefore, distributions to be paid, if any, during calendar year 2016 will include all common units owned by the privately held affiliates of EPCO.

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

Capital Spending

An important part of our business strategy involves expansion through growth capital projects, business combinations and investments in joint ventures. We believe that we are positioned to continue to expand our system of assets through the construction of new facilities and to capitalize on expected increases in natural gas, NGL and crude oil production resulting from development activities in the Rocky Mountains, Mid-Continent and Northeast regions, including the Niobrara, Barnett, Eagle Ford, Permian, Haynesville, Marcellus and Utica Shale plays.

Although our focus in recent years has been on expansion through growth capital projects, management continues to analyze potential business combinations, asset acquisitions, joint ventures and similar transactions with businesses that operate in complementary markets or geographic regions. In light of current business conditions, we expect that these opportunities will increase.

We placed approximately \$900 million of major capital projects into service during the nine months ended September 30, 2015. These projects included an expansion of our Houston Ship Channel LPG export terminal, our Rancho II pipeline and the second segment of our Aegis Ethane Pipeline. During the remainder of 2015, we expect to complete construction and begin commercial operations of growth capital projects costing approximately \$1.8 billion. These projects include another significant expansion of our Houston Ship Channel LPG export terminal and various crude oil pipeline and storage products.

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

	For the Nine Months Ended September 30,	
	2015	2014
Step 2 of Oiltanking acquisition (1)		
Equity instruments (36,827,517 common units of Enterprise)	\$1,408.7	\$--
Acquisition of EFS Midstream (2)	1,045.1	--
Capital spending for property, plant and equipment, net: (3)		
Growth capital projects (4)	2,420.3	1,598.3
Sustaining capital projects (5)	198.8	261.2
Investments in unconsolidated affiliates	130.7	583.3
Other investing activities	5.3	6.0
Total capital spending	\$5,208.9	\$2,448.8

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

(2) Amount represents the initial payment for EFS Midstream in July 2015. For a general description of the acquisition of EFS Midstream, see “Significant Recent Developments” within this Part I, Item 2.

(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 \$11.4 million and \$20.0 million for the nine months ended September 30, 2015 and 2014, respectively. Growth and sustaining capital amounts presented in the table above are presented net of related contributions in aid of construction costs.

(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, 2015 involved projects at our Houston LPG and ethane export terminals and Mont Belvieu complex.

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

Capital spending for the nine months ended September 30, 2015 includes \$1.4 billion of non-cash equity consideration we issued to complete Step 2 of the Oiltanking acquisition. Step 2 represented our acquisition of the noncontrolling

interests in Oiltanking; therefore, approximately \$1.4 billion of noncontrolling interests attributable to Oiltanking was reclassified to limited partners' equity to reflect the February 2015 issuance of 36,827,517 Enterprise common units.

We acquired EFS Midstream in July 2015 for approximately \$2.1 billion in cash, excluding \$125 million of EFS Midstream debt that was extinguished immediately after closing of the transaction on July 8, 2015. Of the \$2.1 billion purchase price, \$1.0 billion was deferred and will be paid no later than the first anniversary of the closing date. For additional information regarding the EFS Midstream acquisition, including an allocation of the purchase price to assets acquired and liabilities assumed, see Note 8 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

In total, capital spending for property, plant and equipment increased \$759.6 million period-to-period primarily due to higher growth capital spending during the nine months ended September 30, 2015. Growth capital spending at our Houston Ship Channel LPG and ethane export facilities increased a combined \$296.6 million period-to-period as work continued at both locations. We recently completed an expansion project at our Houston Ship Channel LPG export terminal that increased our ability to load cargoes of fully refrigerated, low-ethane propane from 7.5 MMBbls per month to approximately 9.0 MMBbls per month. Work continues at this marine terminal facility on another expansion project that will increase our loading capacity from 9.0 MMBbls per month to in excess of 16.0 MMBbls per month. This expansion project is expected to be in service by the end of 2015. Work also continues at our Houston Ship Channel ethane export facility, which we expect to begin operations in the third quarter of 2016.

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Growth capital spending on our Rancho II crude oil pipeline and the expansion of crude oil terminal assets at our ECHO, Houston Ship Channel and Beaumont Marine West terminals increased a combined \$308.4 million period-to-period. The Rancho II crude oil pipeline, which entered commercial service in September 2015, consists of 88 miles of pipeline extending from Sealy, Texas to our ECHO terminal. Current expansion projects at our ECHO, Houston Ship Channel and Beaumont Marine West terminals involve the construction of additional storage capacity and associated distribution pipelines. We continue to complete these terminal expansion projects in phases, with final completion expected in 2016.

Growth capital spending at our Mont Belvieu complex increased \$238.3 million period-to-period primarily due to construction of our PDH facility, which is expected to begin commercial operations in late 2016. In addition, growth capital spending on our Gulf Coast ethane header system increased \$153.8 million period-to-period. Our Gulf Coast ethane header system will be comprised of the newly constructed Aegis Ethane Pipeline and existing South Texas midstream infrastructure. In September 2015, we completed the second segment of our Aegis Ethane Pipeline from Beaumont, Texas to Lake Charles, Louisiana, and we expect to complete the third and final segment of the pipeline by the end of 2015. When completed, our Gulf Coast ethane header system will extend 500 miles from Corpus Christi, Texas to the Mississippi River in Louisiana.

Growth capital spending attributable to our ATEX pipeline and the Rocky Mountain expansion of our Mid-America Pipeline System decreased a combined \$258.8 million period-to-period. Expansion projects involving these assets were largely completed prior to the nine months ended September 30, 2015.

Investments in unconsolidated affiliates for the nine months ended September 30, 2015 decreased \$452.6 million when compared to same period in 2014 primarily due to completion of the Seaway Loop pipeline in December 2014.

Capital Spending Outlook

We currently expect our total capital spending for the remainder of 2015 to approximate \$1.25 billion, which includes \$95 million for sustaining capital expenditures. Our forecast of capital spending for the remainder of 2015 is based on our announced strategic operating and growth plans (through the filing date of this quarterly report), which are dependent upon our ability to generate the required funds from either operating cash flows or other means, including borrowings under debt agreements, the issuance of additional equity and debt securities, and potential divestitures. We may revise our forecast of capital spending due to factors beyond our control, such as adverse economic conditions, weather related issues and changes in supplier prices. Furthermore, our forecast of capital spending may change as a result of decisions made by management at a later date, which may include the addition of costs in connection with unforeseen acquisition opportunities.

Our success in raising capital, including the formation of joint ventures to share costs and risks, continues to be a significant factor in determining how much capital we can invest. We believe our access to capital resources is sufficient to meet the demands of our current and future growth needs and, although we currently expect to make the forecast capital expenditures noted above, we may adjust the timing and amounts of projected expenditures in response to changes in capital market conditions.

Pipeline Integrity Costs

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

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

	For the Three Months Ended September 30, 2015		For the Nine Months Ended September 30, 2014	
Expensed	\$10.7	\$17.6	\$40.9	\$44.4
Capitalized	15.0	11.5	29.6	30.5
Total	\$25.7	\$29.1	\$70.5	\$74.9

We expect the cost of our pipeline integrity program, regardless of whether such costs are capitalized or expensed, to approximate \$29 million for the remainder of 2015. The cost of our pipeline integrity program was \$99 million for the year ended December 31, 2014.

Critical Accounting Policies and Estimates

A discussion of our critical accounting policies and estimates is included in our 2014 Form 10-K. The following 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

Gross operating margin

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by our executive management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment

results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income. For additional information regarding gross operating margin, see Note 12 of the Notes to Unaudited Condensed Consolidated Financial Statements under Part I, Item 1 of this quarterly report.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2015	2014	2015	2014
Total segment gross operating margin	\$1,341.1	\$1,335.1	\$3,978.7	\$3,928.1
Adjustments to reconcile total segment gross operating margin to operating income:				
Subtract depreciation, amortization and accretion expense amounts not reflected in gross operating margin	(351.1)	(322.7)	(1,082.0)	(936.5)
Subtract impairment charges not reflected in gross operating margin	(26.8)	(5.7)	(139.1)	(18.2)
Add net gains or subtract net losses attributable to asset sales and insurance recoveries not reflected in gross operating margin	(12.3)	2.6	(14.7)	99.0
Subtract non-refundable deferred revenues attributable to shipper make-up rights on new pipeline projects reflected in gross operating margin	(3.4)	(21.6)	(39.3)	(66.8)
Add subsequent recognition of deferred revenues attributable to make-up rights not reflected in gross operating margin	10.9	--	45.3	--
Subtract general and administrative costs not reflected in gross operating margin	(49.0)	(50.0)	(143.2)	(150.9)
Operating income	\$909.4	\$937.7	\$2,605.7	\$2,854.7

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

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2015	2014	2015	2014
Distributable cash flow	\$2,501.3	\$974.8	\$4,518.5	\$3,015.6
Adjustments to reconcile distributable cash flow to net cash flows provided by operating activities:				
Add sustaining capital expenditures reflected in distributable cash flow	84.3	106.8	195.8	262.0
	(1,531.4)	(8.3)	(1,537.3)	(121.5)

Subtract cash proceeds from asset sales and insurance recoveries
reflected in distributable cash flow

Net effect of changes in operating accounts not reflected in distributable
cash flow

Other, net	(377.2)	(237.2)	(627.9)	(435.8)
	12.6	(3.6)	42.1	(15.9)
Net cash flows provided by operating activities	\$689.6	\$832.5	\$2,591.2	\$2,704.4

Contractual Obligations

Our consolidated principal debt obligations at September 30, 2015 were approximately \$22.5 billion compared to \$21.39 billion at December 31, 2014. For information regarding the scheduled maturities of such debt, see “Liquidity and Capital Resources – Consolidated Debt” within this Part I, Item 2. See Note 10 of the Notes to Unaudited Condensed Consolidated Financial Statements under Part I, Item 1 of this quarterly report for additional information regarding our consolidated debt obligations.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements that have or are reasonably expected to have a material current or future effect on our financial position, results of operations and cash flows.

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Related Party Transactions

For information regarding our related party transactions, see Note 13 of the Notes to Unaudited Condensed Consolidated Financial Statements included under Part I, Item 1 of this quarterly report.

Item 3. Quantitative and Qualitative Disclosures about Market Risk.

In the normal course of our business operations, we are exposed to certain risks, including changes in interest rates and commodity prices. In order to manage risks associated with assets, liabilities and certain anticipated future transactions, we use derivative instruments such as futures, forward contracts, swaps, options and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities.

Our exposures to market risk have not changed materially since those reported under Part II, Item 7A, “Quantitative and Qualitative Disclosures About Market Risk,” included in our 2014 Form 10-K.

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

§ the derivative instrument functions effectively as a hedge of the underlying risk;

§ the derivative instrument is not closed out in advance of its expected term; and

§ the hedged forecasted transaction occurs within the expected time period.

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

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

Interest Rate Hedging Activities

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

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

Interest rate swaps

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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, 2015 (dollars in millions):

	Number and Type of Derivatives	Notional Amount	Period of Hedge	Rate Swap	Accounting Treatment
Hedged Transaction Outstanding					
Senior Notes OO	10 fixed-to-floating swaps	\$ 750.0	5/2015 to 5/2018	1.65% to 0.79%	Fair value hedge

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

Scenario	Resulting Classification	Portfolio Fair Value at		
		December 31, 2014	September 30, 2015	October 15, 2015
Fair value assuming no change in underlying interest rates	Asset	\$--	\$ 7.6	\$ 9.0
Fair value assuming 10% increase in underlying interest rates	Asset	--	5.9	7.4
Fair value assuming 10% decrease in underlying interest rates	Asset	--	9.4	10.6

Commodity Hedging Activities

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

Derivative Purpose	Volume (1)	Accounting	
	Current (2)	Long-Term (2) Treatment	
<u>Derivatives designated as hedging instruments:</u>			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction (Bcf)	4.9	n/a	Cash flow hedge
Forecasted sales of NGLs (MMBbls) (3)	1.1	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchases of NGLs (MMBbls)	0.1	n/a	Cash flow hedge
Forecasted sales of octane enhancement products (MMBbls)	0.5	n/a	Cash flow hedge
Natural gas marketing:			
Forecasted purchases of natural gas for fuel (Bcf)	6.4	n/a	Cash flow hedge
Forecasted sales of natural gas (Bcf)	0.1	n/a	Cash flow hedge
Natural gas storage inventory management activities (Bcf)	10.2	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	34.6	0.5	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	49.8	n/a	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products (MMBbls)	0.4	n/a	Cash flow hedge
Forecasted sales of refined products (MMBbls)	0.7	n/a	Cash flow hedge
Refined products inventory management activities (MMBbls)	0.2	n/a	Fair value hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	9.0	1.6	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	11.9	1.6	Cash flow hedge
<u>Derivatives not designated as hedging instruments:</u>			
Natural gas risk management activities (Bcf) (4,5)	65.9	9.6	Mark-to-market
NGL risk management activities (MMBbls) (5)	14.9	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (5)	5.8	0.4	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, April 2016 and March 2018, respectively.

(3) Forecasted sales of NGL volumes under natural gas processing exclude 0.7 MMBbls of additional hedges executed under contracts that have been designated as normal sales agreements.

(4) Current and long-term volumes include 38.7 Bcf and 0.9 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.

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

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

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

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

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

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

Scenario	Resulting Classification	Portfolio Fair Value at		
		December 31, 2014	September 30, 2015	October 15, 2015
Fair value assuming no change in underlying commodity prices	Asset	\$5.8	\$ 4.2	\$ 3.8
Fair value assuming 10% increase in underlying commodity prices	Asset (Liability)	2.4	(0.1)	(0.5)
Fair value assuming 10% decrease in underlying commodity prices	Asset	9.2	8.5	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, 2014	September 30, 2015	October 15, 2015
Fair value assuming no change in underlying commodity prices	Asset	\$57.8	\$ 34.6	\$ 53.6
Fair value assuming 10% increase in underlying commodity prices	Asset	47.5	5.2	28.0
Fair value assuming 10% decrease in underlying commodity prices	Asset	68.2	64.0	79.3

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

Scenario	Resulting Classification	Portfolio Fair Value at		
		December 31, 2014	September 30, 2015	October 15, 2015

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Fair value assuming no change in underlying commodity prices	Asset	\$15.6	\$ 6.9	\$3.0
Fair value assuming 10% increase in underlying commodity prices	Asset (Liability)	6.5	(8.6)	(14.0)
Fair value assuming 10% decrease in underlying commodity prices	Asset	24.7	22.5	20.0

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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) Michael A. Creel, our general partner's chief executive officer, (ii) W. Randall Fowler, our general partner's chief administrative officer, 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. Creel 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. Creel, Fowler and Bulawa concluded:

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 (i) and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our principal executive and financial officers, as appropriate to allow for timely decisions regarding required disclosures; and

(ii) that our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

We are continuing to evaluate and implement changes to the processes, policies and other applicable components of our internal control over financial reporting due to our consolidation of the financial statements of Oiltanking effective October 1, 2014 and EFS Midstream effective July 1, 2015. Management continues to evaluate the effectiveness of our internal control procedures and the design of those control procedures as they relate to Oiltanking and EFS Midstream. In accordance with rules promulgated by the U.S. Securities and Exchange Commission, acquired businesses such as Oiltanking and EFS Midstream may be excluded from our assessment of internal control over financial reporting for one year while such businesses are being integrated with our legacy operations. We expect that the evaluation process will be completed for Oiltanking during the fourth quarter of 2015 and for EFS Midstream during the third quarter of 2016.

We followed our normal accounting procedures and internal control processes when recording and disclosing the accounting impacts of the Oiltanking and EFS Midstream acquisitions. In addition, management routinely reviews the results of operations of these acquired businesses prior to their consolidation with the results of operations of our other businesses.

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

The required certifications of Messrs. Creel, 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.

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

Item 1A. Risk Factors.

An investment in our securities involves certain risks. Security holders and potential investors in our securities should carefully consider the supplemental risk described below in addition to the risks described under “Risk Factors” set forth in Part I, Item 1A of our 2014 Form 10-K, in addition to other information in such annual report. The risk factors set forth in in this quarterly report and our 2014 Form 10-K are important factors that could cause our actual results to differ materially from those contained in any written or oral forward-looking statements made by us or on our behalf.

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

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

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

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

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

The following table summarizes our repurchase activity during the nine months ended September 30, 2015:

Period	Total Number of Units Purchased	Average Price Paid per Unit	Total Number of Units Purchased as Part of Publicly	Maximum Number of Units That May Yet
--------	--	--------------------------------------	--	--

			Announced Plans	Be Purchased Under the Plans
February 2015 (1)	628,750	\$ 33.68	--	--
May 2015 (2)	33,492	\$ 34.21	--	--
August 2015 (3)	18,254	\$ 26.93	--	--

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

(2) Of the 87,298 restricted common units that vested in May 2015 and converted to common units, 33,492 units were sold back to us by employees to cover related withholding tax requirements.

(3) Of the 57,150 restricted common units that vested in August 2015 and converted to common units, 18,254 units were sold back to us by employees to cover related withholding tax requirements.

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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 Odffjell 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*
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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
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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).

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- 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).

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- Certificate of Formation of Enterprise Products Holdings LLC (formerly named EPE Holdings, LLC)
3.6 (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).
Certificate of Amendment to Certificate of Formation of Enterprise Products Holdings LLC (formerly named
3.7 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).
Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products Holdings LLC dated
3.8 effective as of September 7, 2011 (incorporated by reference to Exhibit 3.1 to Form 8-K filed September 8, 2011).
Company Agreement of Enterprise Products Operating LLC dated June 30, 2007 (incorporated by reference to
3.9 Exhibit 3.3 to Form 10-Q filed August 8, 2007).
Certificate of Incorporation of Enterprise Products OLPGP, Inc., dated December 3, 2003 (incorporated by
3.10 reference to Exhibit 3.5 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
Bylaws of Enterprise Products OLPGP, Inc., dated December 8, 2003 (incorporated by reference to Exhibit 3.6 to
3.11 Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
Form of Common Unit certificate (incorporated by reference to Exhibit A to Exhibit 3.1 to Form 8-K filed
4.1 August 16, 2011).
Indenture, dated as of March 15, 2000, among Enterprise Products Operating L.P., as Issuer, Enterprise Products
4.2 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).
Second Supplemental Indenture, dated as of February 14, 2003, among Enterprise Products Operating L.P., as
4.3 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).
Third Supplemental Indenture, dated as of June 30, 2007, among Enterprise Products Operating L.P., as Original
4.4 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).
Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products
4.5 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).
Fourth Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as
4.6 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).
Fifth Supplemental Indenture, dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer,
4.7 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).
Sixth Supplemental Indenture, dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer,
4.8 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).
Eighth Supplemental Indenture, dated as of July 18, 2006, among Enterprise Products Operating L.P., as Issuer,
4.9 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).
Ninth Supplemental Indenture, dated as of May 24, 2007, among Enterprise Products Operating L.P., as Issuer,
4.10 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).

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- 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).

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- Twenty-Seventh Supplemental Indenture, dated as of May 7, 2015, among Enterprise Products Operating LLC, as
- 4.25 Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed May 7, 2015).
- 4.26 Form of Global Note representing \$499.2 million principal amount of 6.875% Series B Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.8 to Form 10-K filed March 31, 2003).
- Form of Global Note representing \$350.0 million principal amount of 6.65% Series B Senior Notes due 2034
- 4.27 with attached Guarantee (incorporated by reference to Exhibit 4.19 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005).
- Form of Global Note representing \$250.0 million principal amount of 5.00% Series B Senior Notes due 2015
- 4.28 with attached Guarantee (incorporated by reference to Exhibit 4.31 to Form 10-Q filed November 4, 2005).
- Form of Global Note representing \$250.0 million principal amount of 5.75% Series B Senior Notes due 2035
- 4.29 with attached Guarantee (incorporated by reference to Exhibit 4.32 to Form 10-Q filed November 4, 2005).
- Form of Junior Subordinated Note, including Guarantee (incorporated by reference to Exhibit 4.2 to Form 8-K
- 4.30 filed July 19, 2006).
- Form of Global Note representing \$800.0 million principal amount of 6.30% Senior Notes due 2017 with
- 4.31 attached Guarantee (incorporated by reference to Exhibit 4.38 to Form 10-Q filed November 9, 2007).
- Form of Global Note representing \$700.0 million principal amount of 6.50% Senior Notes due 2019 with
- 4.32 attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed April 3, 2008).
- Form of Global Note representing \$500.0 million principal amount of 5.25% Senior Notes due 2020 with
- 4.33 attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009).
- Form of Global Note representing \$600.0 million principal amount of 6.125% Senior Notes due 2039 with
- 4.34 attached Guarantee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009).
- Form of Global Note representing \$349.7 million principal amount of 6.65% Senior Notes due 2018 with
- 4.35 attached Guarantee (incorporated by reference to Exhibit 4.6 to Form 8-K filed October 28, 2009).
- Form of Global Note representing \$399.6 million principal amount of 7.55% Senior Notes due 2038 with
- 4.36 attached Guarantee (incorporated by reference to Exhibit 4.7 to Form 8-K filed October 28, 2009).
- Form of Global Note representing \$285.8 million principal amount of 7.000% Junior Subordinated Notes due
- 4.37 2067 with attached Guarantee (incorporated by reference to Exhibit 4.8 to Form 8-K filed October 28, 2009).
- Form of Global Note representing \$400.0 million principal amount of 3.70% Senior Notes due 2015 with
- 4.38 attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed May 20, 2010).
- Form of Global Note representing \$1.0 billion principal amount of 5.20% Senior Notes due 2020 with attached
- 4.39 Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed May 20, 2010).
- Form of Global Note representing \$600.0 million principal amount of 6.45% Senior Notes due 2040 with
- 4.40 attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed May 20, 2010).
- Form of Global Note representing \$750.0 million principal amount of 3.20% Senior Notes due 2016 with
- 4.41 attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed January 13, 2011).
- Form of Global Note representing \$750.0 million principal amount of 5.95% Senior Notes due 2041 with
- 4.42 attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed January 13, 2011).

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- 4.43 Form of Global Note representing \$650.0 million principal amount of 4.05% Senior Notes due 2022 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed August 24, 2011).
- 4.44 Form of Global Note representing \$600.0 million principal amount of 5.70% Senior Notes due 2042 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed August 24, 2011).
- 4.45 Form of Global Note representing \$750.0 million principal amount of 4.85% Senior Notes due 2042 with attached Guarantee (incorporated by reference to Exhibit 4.25 to Form 10-Q filed May 10, 2012).
- 4.46 Form of Global Note representing \$650.0 million principal amount of 1.25% Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed August 13, 2012).
- 4.47 Form of Global Note representing \$1.1 billion principal amount of 4.45% Senior Notes due 2043 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed August 13, 2012).
- 4.48 Form of Global Note representing \$1.25 billion principal amount of 3.35% Senior Notes due 2023 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed March 18, 2013).
- 4.49 Form of Global Note representing \$1.0 billion principal amount of 4.85% Senior Notes due 2044 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed March 18, 2013).
- 4.50 Form of Global Note representing \$850.0 million principal amount of 3.90% Senior Notes due 2024 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed February 12, 2014).
- 4.51 Form of Global Note representing \$1.15 billion principal amount of 5.10% Senior Notes due 2045 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed February 12, 2014).
- 4.52 Form of Global Note representing \$800.0 million principal amount of 2.55% Senior Notes due 2019 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 14, 2014).
- 4.53 Form of Global Note representing \$1.15 billion principal amount of 3.75% Senior Notes due 2025 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 14, 2014).
- 4.54 Form of Global Note representing \$400.0 million principal amount of 4.95% Senior Notes due 2054 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 14, 2014).
- 4.55 Form of Global Note representing \$400.0 million principal amount of 4.85% Senior Notes due 2044 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 14, 2014).
- 4.56 Form of Global Note representing \$750.0 million principal amount of 1.65% Senior Notes due 2018 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed May 7, 2015).
- 4.57 Form of Global Note representing \$875.0 million principal amount of 3.70% Senior Notes due 2026 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed May 7, 2015).
- 4.58 Form of Global Note representing \$875.0 million principal amount of 4.90% Senior Notes due 2046 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 8-K filed May 7, 2015).
- 4.59 Replacement Capital Covenant, dated July 18, 2006, executed by Enterprise Products Operating L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 99.1 to Form 8-K filed July 19, 2006).
- 4.60 First Amendment to Replacement Capital Covenant dated August 25, 2006, executed by Enterprise Products Operating L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 99.2 to Form 8-K filed August 25, 2006).
- 4.61 Replacement Capital Covenant, dated May 24, 2007, executed by Enterprise Products Operating L.P. and Enterprise Products Partners L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 99.1 to Form 8-K filed May 24, 2007).

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- Replacement Capital Covenant, dated October 27, 2009, executed by Enterprise Products Operating LLC and
- 4.62 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).
- Amendment to Replacement Capital Covenants, dated May 6, 2015, executed by Enterprise Products Operating
- 4.63 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).
- Indenture, dated February 20, 2002, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline
- 4.64 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).
- Second Supplemental Indenture, dated June 27, 2002, by and among TEPPCO Partners, L.P., as Issuer, TE
- 4.65 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).
- Full Release of Guarantee, dated July 31, 2006, by Wachovia Bank, National Association, as Trustee, in favor of
- 4.66 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).
- Fourth Supplemental Indenture, dated June 30, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE
- 4.67 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).
- Sixth Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE
- 4.68 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).
- Seventh Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE
- 4.69 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).
- Eighth Supplemental Indenture, dated October 27, 2009, by and among TEPPCO Partners, L.P., as Issuer, TE
- 4.70 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).
- Full Release of Guarantee, dated November 23, 2009, of TE Products Pipeline Company, LLC, TCTM, L.P.,
- 4.71 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).
- Indenture, dated May 14, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company,
- 4.72 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).

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4.73	First Supplemental Indenture, dated May 18, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TEPPCO Partners, L.P. on May 18, 2007).
4.74	Second Supplemental Indenture, dated as of June 30, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Existing Subsidiary Guarantors, TE Products Pipeline Company, LLC and TEPPCO Midstream Companies, LLC, as New Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TE Products Pipeline Company, LLC on July 6, 2007).
4.75	Third Supplemental Indenture, dated as of October 27, 2009, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TEPPCO Partners, L.P. on October 28, 2009).
4.76	Full Release of Guarantee, dated as of November 23, 2009, of TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P. by The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.70 to Form 10-K filed on March 1, 2010).
4.77	Registration Rights Agreement by and between Enterprise Products Partners L.P. and Oiltanking Holding Americas, Inc. dated as of October 1, 2014 (incorporated by reference to Exhibit 4.1 to Form 8-K filed on October 1, 2014).
10.1	Equity Distribution Agreement, dated August 10, 2015, 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, Mitsubishi UFJ Securities (USA), Inc., Mizuho Securities USA Inc., Morgan Stanley & Co. LLC, Raymond James & Associates, Inc., RBC Capital Markets, LLC, Scotia Capital (USA) Inc., SMBC Nikko Securities America, Inc., SunTrust Robinson Humphrey, Inc., UBS Securities LLC, USCA Securities LLC and Wells Fargo Securities, LLC (incorporated by reference to Exhibit 1.1 to Form 8-K filed August 10, 2015).
10.2	First Amendment to 364-Day Revolving Credit Agreement dated as of September 16, 2015, 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 September 16, 2015).
10.3	Second Amendment dated as of September 16, 2015 to Revolving Credit Agreement dated as of September 7, 2011, as amended by First Amendment to Revolving Credit Agreement dated as of June 19, 2013, among Enterprise Products Operating LLC, Wells Fargo Bank, National Association, as Administrative Agent, the Lenders and Issuing Banks party thereto, Citibank, N.A., 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 Wells Fargo Securities, LLC, Citigroup Global Markets Inc., 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 10.2 to Form 8-K filed September 16, 2015).

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12.1#	Computation of ratio of earnings to fixed charges for the nine months ended September 30, 2015 and each of the years ended December 31, 2014, 2013, 2012, 2011 and 2010.
31.1#	Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise Products Partners L.P.'s quarterly report on Form 10-Q for the nine months ended September 30, 2015.
31.2#	Sarbanes-Oxley Section 302 certification of W. Randall Fowler for Enterprise Products Partners L.P.'s quarterly report on Form 10-Q for the nine months ended September 30, 2015.
31.3#	Sarbanes-Oxley Section 302 certification of Bryan F. Bulawa for Enterprise Products Partners L.P.'s quarterly report on Form 10-Q for the nine months ended September 30, 2015.
32.1#	Sarbanes-Oxley Section 906 certification of Michael A. Creel for Enterprise Products Partners L.P.'s quarterly report on Form 10-Q for the nine months ended September 30, 2015.
32.2#	Sarbanes-Oxley Section 906 certification of W. Randall Fowler for Enterprise Products Partners L.P.'s quarterly report on Form 10-Q for the nine months ended September 30, 2015.
32.3#	Sarbanes-Oxley Section 906 certification of Bryan F. Bulawa for Enterprise Products Partners L.P.'s quarterly report on Form 10-Q for the nine months ended September 30, 2015.
101.CAL#	XBRL Calculation Linkbase Document
101.DEF#	XBRL Definition Linkbase Document
101.INS#	XBRL Instance Document
101.LAB#	XBRL Labels Linkbase Document
101.PRE#	XBRL Presentation Linkbase Document
101.SCH#	XBRL Schema Document

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

#Filed with this report.

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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 6, 2015.

ENTERPRISE PRODUCTS PARTNERS L.P.

(A Delaware Limited Partnership)

By: Enterprise Products Holdings LLC, as General Partner

By: /s/ Michael J. Knesek

Name: Michael J. Knesek

Title: Senior Vice President, Controller and Principal
Accounting Officer of the General Partner