Calumet Specialty Products Partners, L.P.
Form 10-Q
August 07, 2017

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

Form 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2017
OR
TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM TO
Commission File Number: 000-51734

Calumet Specialty Products Partners, L.P.
(Exact Name of Registrant as Specified in Its Charter)

Delaware	35-1811116
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification Number)

2780 Waterfront Parkway East Drive, Suite 200	
Indianapolis, Indiana	46214
(Address of Principal Executive Officers)	(Zip Code)

(317) 328-5660
(Registrant's Telephone Number, Including Area Code)
None
(Former Name, Former Address and Former Fiscal Year, If Changed Since Last Report)

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 Registration S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

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

Emerging growth company
If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).   Yes   No
On August 7, 2017, there were 76,729,706 common units outstanding.

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CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
QUARTERLY REPORT
For the Three and Six Months Ended June 30, 2017
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FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q (this “Quarterly Report”) includes certain “forward-looking statements.” These statements can be identified by the use of forward-looking terminology including “may,” “intend,” “believe,” “expect,” “anticipate,” “estimate,” “continue,” “plan,” “should,” “could,” “would,” or other similar words. The statements regarding (i) estimated capital expenditures as a result of required audits or required operational changes or other environmental and regulatory liabilities, (ii) our expectations regarding annual EBITDA contributions from our multi-year, self-help program, (iii) our anticipated levels of, use and effectiveness of derivatives to mitigate our exposure to crude oil price changes, natural gas price changes and fuel products price changes, (iv) estimated costs of complying with the U.S. Environmental Protection Agency’s (“EPA”) Renewable Fuel Standard (“RFS”), including the prices paid for Renewable Identification Numbers (“RINs”), (v) our ability to meet our financial commitments, minimum quarterly distributions to our unitholders, debt service obligations, debt instrument covenants, contingencies and anticipated capital expenditures and (vi) our access to capital to fund capital expenditures and our working capital needs and our ability to obtain debt or equity financing on satisfactory terms, as well as other matters discussed in this Quarterly Report that are not purely historical data, are forward-looking statements. These forward-looking statements are based on our current expectations and beliefs concerning future developments and their potential effect on us. While management believes that these forward-looking statements are reasonable as and when made, there can be no assurance that future developments affecting us will be those that we anticipate. All comments concerning our expectations for future sales and operating results are based on our forecasts for our existing operations and do not include the potential impact of any future acquisition or disposition transactions. Our forward-looking statements involve significant risks and uncertainties (some of which are beyond our control) and assumptions that could cause actual results to differ materially from our historical experience and our present expectations or projections. Known material factors that could cause our actual results to differ from those in the forward-looking statements are those described in (i) Part II, Item 7A “Quantitative and Qualitative Disclosures About Market Risk” and Part I, Item 1A “Risk Factors” in our Annual Report on Form 10-K for the fiscal year ended December 31, 2016 (“2016 Annual Report”), (ii) Part II, Item 1A “Risk Factors” in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2017 (“Q1 Quarterly Report”) and (iii) Part I, Item 3 “Quantitative and Qualitative Disclosures About Market Risk” and Part II, Item 1A “Risk Factors” in this Quarterly Report. Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly update or revise any forward-looking statements after the date they are made, whether as a result of new information, future events or otherwise.

References in this Quarterly Report to “Calumet Specialty Products Partners, L.P.,” “Calumet,” “the Company,” “we,” “our,” “
or like terms refer to Calumet Specialty Products Partners, L.P. and its subsidiaries. References in this Quarterly Report to “our general partner” refer to Calumet GP, LLC, the general partner of Calumet Specialty Products Partners, L.P.

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PART I
Item 1. Financial Statements
CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
CONDENSED CONSOLIDATED BALANCE SHEETS

	June 30, 2017	December 31, 2016
	(Unaudited)	
	(In millions, except unit data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$26.6	$ 4.2
Accounts receivable:		
Trade	277.5	216.4
Other	11.8	22.3
	289.3	238.7
Inventories	438.5	386.2
Derivative assets	1.0	0.8
Prepaid expenses and other current assets	13.9	11.0
Total current assets	769.3	640.9
Property, plant and equipment, net	1,633.2	1,678.0
Investment in unconsolidated affiliates	10.1	10.3
Goodwill	177.2	177.2
Other intangible assets, net	162.1	178.5
Other noncurrent assets, net	36.6	40.3
Total assets	$2,788.5	$ 2,725.2
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$312.2	$ 295.5
Accrued interest payable	52.4	52.5
Accrued salaries, wages and benefits	22.8	11.5
Other taxes payable	21.4	20.8
Obligations under inventory financing agreements	103.5	—
Other current liabilities	46.2	99.6
Current portion of long-term debt	3.4	3.5
Derivative liabilities	2.1	14.8
Total current liabilities	564.0	498.2
Deferred income taxes	2.3	2.3
Pension and postretirement benefit obligations	10.9	11.3
Other long-term liabilities	0.9	1.0
Long-term debt, less current portion	1,986.4	1,993.7
Total liabilities	2,564.5	2,506.5
Commitments and contingencies		
Partners' capital:		
Limited partners' interest 76,729,706 units and 76,392,258 units, issued and outstanding as of June 30, 2017 and December 31, 2016, respectively	216.3	211.2
General partner's interest	16.0	15.8
Accumulated other comprehensive loss	(8.3)	(8.3)

Total partners' capital	224.0	218.7
Total liabilities and partners' capital	$2,788.5	$ 2,725.2

See accompanying notes to unaudited condensed consolidated financial statements.

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CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In millions, except per unit and unit data)			
Sales	$1,030.9	$972.9	$1,968.3	$1,685.9
Cost of sales	870.5	841.6	1,668.4	1,468.4
Gross profit	160.4	131.3	299.9	217.5
Operating costs and expenses:				
Selling	28.2	26.2	55.7	56.7
General and administrative	33.6	24.8	65.4	52.4
Transportation	41.1	45.0	81.7	84.2
Taxes other than income taxes	4.9	4.2	10.4	9.9
Asset impairment	—	33.4	0.4	33.4
Other	1.1	0.3	3.0	2.3
Operating income (loss)	51.5	(2.6)	83.3	(21.4)
Other income (expense):				
Interest expense	(44.5)	(42.8)	(88.4)	(73.1)
Gain on derivative instruments	1.3	17.8	7.0	10.1
Loss from unconsolidated affiliates	(0.1)	(7.1)	(0.2)	(18.2)
Loss from sale of unconsolidated affiliates	—	(113.4)	—	(113.4)
Other	0.5	0.5	0.7	0.9
Total other expense	(42.8)	(145.0)	(80.9)	(193.7)
Net income (loss) before income taxes	8.7	(147.6)	2.4	(215.1)
Income tax expense (benefit)	(0.9)	0.3	(1.0)	0.5
Net income (loss)	$9.6	$(147.9)	$3.4	$(215.6)
Allocation of net income (loss):				
Net income (loss)	$9.6	$(147.9)	$3.4	$(215.6)
Less:				
General partner’s interest in net income (loss)	0.2	(2.9)	0.1	(4.3)
Non-vested share based payments	0.2	—	0.2	—
Net income (loss) available to limited partners	$9.2	$(145.0)	$3.1	$(211.3)
Weighted average limited partner units outstanding:				
Basic	77,554,815	76,761,504	77,485,058	76,491,775
Diluted	77,714,112	76,761,504	77,725,656	76,491,775
Limited partners’ interest basic and diluted net income (loss) per unit	$0.12	$(1.89)	$0.04	$(2.76)
Cash distributions declared per limited partner unit	$—	$—	$—	$0.685

See accompanying notes to unaudited condensed consolidated financial statements.

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CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In millions)			
Net income (loss)	$9.6	$(147.9)	$3.4	$(215.6)
Other comprehensive (income) loss:				
Cash flow hedges:				
Cash flow hedge gain reclassified to net income (loss)	—	(2.3)	—	(4.4)
Defined benefit pension and retiree health benefit plans	—	0.1	—	0.1
Total other comprehensive loss	—	(2.2)	—	(4.3)
Comprehensive income (loss) attributable to partners’ capital	$9.6	$(150.1)	$3.4	$(219.9)

See accompanying notes to unaudited condensed consolidated financial statements.

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CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL

	Accumulated Other Comprehensive Loss	Partners' Capital General Partner	Partners' Capital Limited Partners	Total
	(In millions)			
Balance at December 31, 2016	$(8.3)	$15.8	$211.2	$218.7
Net income	—	0.1	3.3	3.4
Amortization of phantom units	—	—	2.2	2.2
Settlement of tax withholdings on equity-based incentive compensation	—	—	(0.4)	(0.4)
Contributions from Calumet GP, LLC	—	0.1	—	0.1
Balance at June 30, 2017	$(8.3)	$16.0	$216.3	$224.0

See accompanying notes to unaudited condensed consolidated financial statements.

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CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Six Months Ended June 30,	
	2017	2016
	(In millions)	
Operating activities		
Net income (loss)	$3.4	$(215.6)
Adjustments to reconcile net income (loss) to net cash used in operating activities:		
Depreciation and amortization	82.0	82.6
Amortization of turnaround costs	14.0	17.4
Non-cash interest expense	4.8	4.6
Provision for doubtful accounts	0.1	0.5
Unrealized gain on derivative instruments	(11.9)	(28.4)
Asset impairment	0.4	33.4
(Gain) loss on disposal of fixed assets	1.5	(0.7)
Non-cash equity based compensation	3.3	2.9
Deferred income tax expense (benefit)	0.1	(0.2)
Lower of cost or market inventory adjustment	(8.0)	(44.4)
Loss from unconsolidated affiliates	0.2	18.2
Loss on sale of unconsolidated affiliates	—	113.4
Other non-cash activities	3.3	2.3
Changes in assets and liabilities:		
Accounts receivable	(50.7)	(60.0)
Inventories	(44.3)	(10.3)
Prepaid expenses and other current assets	(2.1)	(1.5)
Derivative activity	(0.3)	(10.4)
Turnaround costs	(10.3)	(8.1)
Other assets	—	(0.4)
Accounts payable	24.2	35.1
Accrued interest payable	(0.1)	9.1
Accrued salaries, wages and benefits	10.2	(16.0)
Other taxes payable	0.6	3.2
Other liabilities	(55.6)	22.5
Pension and postretirement benefit obligations	(0.4)	(0.9)
Net cash used in operating activities	(35.6)	(51.7)
Investing activities		
Additions to property, plant and equipment	(30.0)	(87.9)
Investment in unconsolidated affiliates	—	(41.8)
Proceeds from sale of unconsolidated affiliates	—	29.0
Proceeds from sale of property, plant and equipment	—	1.9
Net cash used in investing activities	(30.0)	(98.8)
Financing activities		
Proceeds from borrowings — revolving credit facility	606.9	479.0
Repayments of borrowings — revolving credit facility	(616.7)	(589.9)
Proceeds from borrowings — senior notes	—	393.1
Repayments of borrowings — related party note	—	(34.5)
Payments on capital lease obligations	(4.5)	(4.1)
Proceeds from inventory financing agreements	105.4	—

Other financing activities	(0.7)	2.4
Debt issuance costs	(2.1)	(9.9)
Contributions from Calumet GP, LLC	0.1	0.2
Taxes paid for phantom unit grants	(0.4)	(1.8)
Distributions to partners	—	(57.4)
Net cash provided by financing activities	88.0	177.1
Net increase in cash and cash equivalents	22.4	26.6
Cash and cash equivalents at beginning of period	4.2	5.6
Cash and cash equivalents at end of period	$26.6	$32.2
Supplemental disclosure of non-cash financing and investing activities		
Non-cash property, plant and equipment additions	$6.5	$20.5

See accompanying notes to unaudited condensed consolidated financial statements.

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CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

1. Description of the Business

Calumet Specialty Products Partners, L.P. (the “Company”) is a publicly traded Delaware limited partnership listed on the NASDAQ Global Select Market (“NASDAQ”) under the ticker symbol “CLMT.” The general partner of the Company is Calumet GP, LLC, a Delaware limited liability company. As of June 30, 2017, the Company had 76,729,706 limited partner common units and 1,565,912 general partner equivalent units outstanding. The general partner owns 2% of the Company and all of the incentive distribution rights (as defined in the Company’s partnership agreement), while the remaining 98% is owned by limited partners. The general partner employs all of the Company’s employees and the Company reimburses the general partner for certain of its expenses.

The Company is engaged in the production and marketing of crude oil-based specialty products including lubricating oils, white mineral oils, solvents, petrolatums and waxes and fuel and fuel related products including gasoline, diesel, jet fuel, asphalt and heavy fuel oils, in addition to oilfield services and products. The Company owns and leases additional facilities, primarily related to production and distribution of specialty, fuel and oilfield services products, throughout the United States (“U.S.”).

The unaudited condensed consolidated financial statements of the Company as of June 30, 2017, and for the three and six months ended June 30, 2017 and 2016, included herein have been prepared, without audit, pursuant to the rules and regulations of the Securities and Exchange Commission (“SEC”). Certain information and disclosures normally included in the consolidated financial statements prepared in accordance with generally accepted accounting principles (“GAAP”) in the U.S. have been condensed or omitted pursuant to such rules and regulations, although the Company believes that the following disclosures are adequate to make the information presented not misleading. The preparation of the unaudited condensed consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the unaudited condensed consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. These unaudited condensed consolidated financial statements reflect all adjustments that, in the opinion of management, are necessary to present fairly the results of operations for the interim periods presented. All adjustments are of a normal nature, unless otherwise disclosed. The results of operations for the three and six months ended June 30, 2017 are not necessarily indicative of the results that may be expected for the year ending December 31, 2017. These unaudited condensed consolidated financial statements should be read in conjunction with the Company’s 2016 Annual Report.

2. Summary of Significant Accounting Policies

Reclassifications

Certain amounts in the prior years’ unaudited condensed consolidated financial statements have been reclassified to conform to the current year presentation.

Other Current Liabilities

Other current liabilities consisted of the following as of June 30, 2017 and December 31, 2016 (in millions):

	June 30, 2017	December 31, 2016
RINs Obligation	$ 25.6	$ 79.3
Other	20.6	20.3
Total	$ 46.2	$ 99.6

The Company’s RINs obligation (“RINs Obligation”) represents a liability for the purchase of RINs to satisfy the EPA requirement to blend biofuels into the fuel products it produces pursuant to the EPA’s RFS. RINs are assigned to biofuels produced in the U.S. as required by the EPA. The EPA sets annual quotas for the percentage of biofuels that must be blended into transportation fuels consumed in the U.S. and, as a producer of motor fuels from petroleum, the Company is required to blend biofuels into the fuel products it produces at a rate that will meet the EPA’s annual quota. To the extent the Company is unable to blend biofuels at that rate, it must purchase RINs in the open market to satisfy the annual requirement. The Company’s RINs Obligation is based on the amount of RINs it must purchase and the price of those RINs as of the balance sheet date.

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The Company uses the inventory model to account for RINs, measuring acquired RINs at weighted-average cost. The cost of RINs used each period is charged to cost of sales with cash inflows and outflows recorded in the operating cash flow section of the unaudited condensed consolidated statements of cash flows. The liability is calculated by multiplying the RINs shortage (based on actual results) by the period end RIN spot price. The Company recognizes an asset at the end of each reporting period in which it has generated RINs in excess of its RINs Obligation. The asset is calculated by multiplying the RINs surplus (based on actual results) by the period end RIN spot price. The value of RINs in excess of the RINs Obligation, if any, would be reflected in other current assets on the condensed consolidated balance sheets. RINs generated in excess of the Company's current RINs Obligation may be sold or held to offset future RINs Obligations. Any such sales of excess RINs are recorded in cost of sales in the unaudited condensed consolidated statements of operations. The assets and liabilities associated with our RINs Obligation are considered recurring fair value measurements. See Note 5 for further information on the Company's RINs Obligation.

New Accounting Pronouncements

In May 2017, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2017-09, Compensation - Stock Compensation (Topic 718) - Scope of Modification Accounting ("ASU 2017-09"). ASU 2017-09 amends prior guidance by further defining when a change to the terms of a share-based award are required to be accounted for as a modification under the rules by providing specific criteria. ASU 2017-09 is effective for annual periods beginning after December 15, 2017. The adoption of ASU 2017-09 is not expected to have an impact on the Company's unaudited condensed consolidated financial statements.

In March 2017, the FASB issued ASU No. 2017-07, Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post-Retirement Benefit Cost ("ASU 2017-07"). The changes to the standard require employers to report the service cost component in the same line item as other compensation costs arising from services rendered by employees during the reporting period. The other components of net benefit costs will be presented in the statement of operations separately from the service cost and outside of a subtotal of operating income (loss). In addition, only the service cost component may be eligible for capitalization where applicable. ASU 2017-07 is effective for annual periods beginning after December 15, 2017. The adoption of ASU 2017-07 is not expected to have an impact on the Company's unaudited condensed consolidated financial statements.

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842) ("ASU 2016-02"), which supersedes the lease accounting requirements in Accounting Standards Codification ("ASC") Topic 840, Leases. ASU 2016-02 provides principles for the recognition, measurement, presentation and disclosure of leases for both lessees and lessors. The new standard requires lessees to apply a dual approach, classifying leases as either finance or operating leases based on the principle of whether or not the lease is effectively a financed purchase by the lessee. This classification will determine whether lease expense is recognized based on an effective interest method or on a straight-line basis over the term of the lease, respectively. A lessee is also required to record a right-of-use asset and a lease liability for all leases with a term of greater than twelve months regardless of classification. Leases with a term of twelve months or less will be accounted for similar to existing guidance for operating leases. The amendments in this standard are effective for fiscal years (including interim periods) beginning after December 15, 2018, with early adoption permitted and modified retrospective application required. The Company is currently evaluating the impact of this standard on its consolidated financial statements.

In January 2016, the FASB issued ASU No. 2016-01, Financial Instruments — Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities ("ASU 2016-01"). ASU 2016-01 requires that (i) equity investments in unconsolidated entities that are not accounted for under the equity method of accounting generally be measured at fair value with changes recognized in net income (loss) and (ii) when the fair value option has been elected for financial liabilities, changes in fair value due to instrument-specific credit risk be recognized separately in other comprehensive income (loss). Additionally, ASU 2016-01 changes the presentation and disclosure requirements for financial instruments. The amendments in this standard are generally effective for fiscal years (including interim periods) beginning after December 15, 2017, with early adoption not permitted. The adoption of ASU 2016-01 is not expected to have an impact on the Company's unaudited condensed consolidated financial statements.

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606) ("ASU 2014-09"), which supersedes the revenue recognition requirements in Accounting Standard Codification Topic 605, Revenue Recognition. ASU 2014-09 is based on the principle that revenue is recognized to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This ASU also requires enhanced disclosures. In August 2015, the FASB issued ASU No. 2015-14, Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date, which defers the original effective date by one year to annual and interim periods beginning after December 15, 2017, with early adoption permitted as of the original effective date. ASU 2014-09 allows for either a full retrospective or a modified retrospective transition method. In March, April, May and December 2016, the FASB clarified the implementation guidance on principal versus agent considerations, identifying performance obligations, licensing, collectibility, presentation of sales taxes, non-cash consideration, transition, the scope of Topic 606, impairment testing, policy elections over determining the provision for losses on certain types of contracts, the accrual of advertising costs and disclosure requirements.

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All amendments are effective with the same date as ASU 2014-09. The Company is currently evaluating the impact of these standards on its unaudited condensed consolidated financial statements. The Company is required to adopt ASU 2014-09 as of January 1, 2018, expects to use the modified retrospective approach and is in the process of evaluating the full impact of adoption on the Company's financial reporting. The Company has an implementation work team evaluating contracts from the various revenue streams across all of its business segments to evaluate and implement changes to business processes, systems and controls.

Based on the evaluation performed to date, the Company has identified some contracts within the oilfield services segment that include implicit arrangements that could be considered material rights under the new standard. Additionally, these contracts contain elements of variable consideration that may impact the total transaction price for these contracts. The Company does not believe that these elements would result in a material change to how revenue would be recognized for these contracts upon the adoption of ASU 2014-09.

Based on the evaluation performed to date, the Company has identified some agreements with distributors within the specialty products segment that are subject to rebate and incentive programs that could contain elements of material rights and/or variable consideration. The Company does not believe that these elements would result in a material change to how revenue would be recognized for these agreements upon the adoption of ASU 2014-09.

The Company continues to analyze the full impact on its operating segments of the adoption of ASU 2014-09, which may result in differences between current revenue recognition practices and those required by ASU 2014-09 that may be material. As part of the Company's evaluation, it has segregated its revenue streams into categories which will serve as the basis for the continuing accounting analysis on, and documentation of revenues, as it relates to the impact of ASU 2014-09. In addition, the Company continues to actively monitor outstanding issues currently being addressed by the American Institute of Certified Public Accountants' Revenue Recognition Working Group and the FASB's Transition Resource Group, since conclusions reached by these groups may impact its application of ASU 2014-09.

3. Inventories

The cost of inventory is recorded using the last-in, first-out ("LIFO") method. An actual valuation of inventory under the LIFO method can be made only at the end of each year based on the inventory levels and costs at that time. Accordingly, interim LIFO calculations are based on management's estimates of expected year-end inventory levels and costs and are subject to the final year-end LIFO inventory valuation. Costs include crude oil and other feedstocks, labor, processing costs and refining overhead costs. Inventories are valued at the lower of cost or market value. The replacement cost of these inventories, based on current market values, would have been $34.4 million and $14.4 million lower as of June 30, 2017, and December 31, 2016, respectively.

On March 31, 2017 and June 19, 2017, the Company sold inventory comprised of crude oil and refined products to Macquarie Energy North America Trading Inc. ("Macquarie") under Supply and Offtake Agreements as described in Note 6 — "Inventory Financing Agreements" related to the Great Falls and Shreveport refineries, respectively. The crude oil remains in the legal title of Macquarie and is stored in the Company's refinery storage tanks governed by storage agreements. Legal title to the crude oil passes to the Company at the storage tank outlet. After processing, Macquarie takes title to the refined products stored in the Company's storage tanks until sold to third parties. The Company records the inventory owned by Macquarie on the Company's behalf as inventory with a corresponding obligation on the Company's condensed consolidated balance sheets because Macquarie maintains the risk of loss until the refined products are sold to third parties and the Company is obligated to repurchase the inventory in certain scenarios. The agreements are accounted for similar to a product financing arrangement.

Inventories consist of the following (in millions):

	June 30, 2017			December 31, 2016		
	Titled Inventory	Supply and Offtake Agreements (1)	Total	Titled Inventory	Supply and Offtake Agreements (1)	Total
Raw materials	$49.0	$ 15.0	$64.0	$57.4	$ —	$57.4
Work in process	49.0	24.5	73.5	74.2	—	74.2
Finished goods	244.1	56.9	301.0	254.6	—	254.6

$342.1	$ 96.4	$438.5	$386.2	$ —	$386.2

[1] Amounts represent LIFO value and do not necessarily represent the value at which the inventory was sold. Refer to Note 6 for further information.
Under the LIFO method, the most recently incurred costs are charged to cost of sales and inventories are valued at the earliest acquisition costs. In addition, the use of the LIFO inventory method may result in increases or decreases to cost of sales in years

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that inventory volumes decline as the result of charging cost of sales with LIFO inventory costs generated in prior periods. In periods of rapidly declining prices, LIFO inventories may have to be written down to market value due to the higher costs assigned to LIFO layers in prior periods. Such write downs are subject to reversal in subsequent periods, not to exceed LIFO cost, if prices recover. During the three months ended June 30, 2017 and 2016, the Company recorded decreases of $4.0 million and $36.3 million, respectively, in cost of sales in the unaudited condensed consolidated statements of operations due to the lower of cost or market ("LCM") valuation. During the six months ended June 30, 2017 and 2016, the Company recorded decreases of $8.0 million and $44.4 million, respectively, in cost of sales in the unaudited condensed consolidated statements of operations due to the LCM valuation.

4. Investment In Unconsolidated Affiliates

The following table summarizes the Company's investments in unconsolidated affiliates as of June 30, 2017, and December 31, 2016 (in millions):

	June 30, 2017		December 31, 2016	
	Investment	Percent Ownership	Investment	Percent Ownership
Pacific New Investment Limited	$9.6	23.8 %	$9.6	23.8 %
Other	0.5		0.7	
Total	$10.1		$10.3	

Pacific New Investment Limited and Shandong Hi-Speed Hainan Development Co., Ltd.

On August 5, 2015, the Company and The Heritage Group, a related party, formed Pacific New Investment Limited ("PACNIL") for the purpose of investing in a joint venture with Shandong Hi-Speed Materials Group Corporation and China Construction Installation Engineering Co., Ltd. to construct, develop and operate a solvents refinery in mainland China. The joint venture is named Shandong Hi-Speed Hainan Development Co., Ltd. ("Hi-Speed"). The Company invested $4.8 million in June 2016 and $4.8 million in October 2016. As of June 30, 2017 and December 31, 2016, the Company owned an equity interest of approximately 23.8% in PACNIL, and through that ownership the Company owned an equity interest of approximately 6.0% in Hi-Speed. PACNIL wishes to exit its investment in Hi-Speed. The Company and PACNIL believe they will fully recover their investment in the Hi-Speed joint venture.

The Company accounts for its ownership in PACNIL under the equity method of accounting. As of June 30, 2017 and December 31, 2016, the Company had an investment of $9.6 million in PACNIL, primarily related to the purchase of equity in the Hi-Speed joint venture.

Dakota Prairie Refining, LLC

On June 27, 2016, the Company consummated the sale of its 50% equity interest in Dakota Prairie Refining, LLC ("Dakota Prairie") to joint venture partner WBI Energy, Inc. ("WBI"), a wholly owned subsidiary of MDU Resources Group, Inc. ("MDU"). Concurrent with the Company's sale of its equity interest in Dakota Prairie to WBI, Tesoro Refining & Marketing Company LLC ("Tesoro") acquired 100% of Dakota Prairie from WBI in a separate transaction that closed on June 27, 2016.

Under the terms of the definitive agreement with WBI, the Company received consideration of $28.5 million, which was offset by the Company's repayment of $36.0 million in borrowings under Dakota Prairie's revolving credit facility. In addition, the Company's $39.4 million letter of credit supporting the Dakota Prairie revolving credit facility was terminated. As part of the transaction, MDU and WBI released the Company from all liabilities arising out of or related to Dakota Prairie. In addition, Tesoro and Dakota Prairie released the Company from all liabilities arising out of the organization, management and operation of Dakota Prairie, subject to certain limited exceptions. Further, WBI agreed to indemnify the Company from all liabilities arising out of or related to Dakota Prairie, subject to certain limited exceptions. As a result of the sale of Dakota Prairie, the Company recorded a loss on sale of unconsolidated affiliate of $113.9 million during the six months ended June 30, 2016.

5. Commitments and Contingencies

From time to time, the Company is a party to certain claims and litigation incidental to its business, including claims made by various regulatory and taxation authorities, such as the EPA, various state environmental regulatory bodies, the Internal Revenue Service, various state and local departments of revenue and the federal Occupational Safety and Health Administration ("OSHA"), as the result of audits or reviews of the Company's business. In addition, the Company has property, business interruption, general liability and various other insurance policies that may result in certain losses or expenditures being reimbursed to the Company.

Environmental

The Company conducts crude oil and specialty hydrocarbon refining, blending and terminal operations in addition to providing oilfield services and products, and such activities are subject to stringent federal, state, regional and local laws and regulations

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governing worker health and safety, the discharge of materials into the environment and environmental protection. These laws and regulations impose obligations that are applicable to the Company’s operations, such as requiring the acquisition of permits to conduct regulated activities, restricting the manner in which the Company may release materials into the environment, requiring remedial activities or capital expenditures to mitigate pollution from former or current operations, requiring the application of specific health and safety criteria addressing worker protection and imposing substantial liabilities for pollution resulting from its operations. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil and criminal penalties; the imposition of investigatory, remedial or corrective action obligations or the incurrence of capital expenditures; the occurrence of delays in the permitting, development or expansion of projects and the issuance of injunctive relief limiting or prohibiting Company activities. Moreover, certain of these laws impose joint and several, strict liability for costs required to remediate and restore sites where petroleum hydrocarbons, wastes or other materials have been released or disposed. In addition, new laws and regulations, new interpretations of existing laws and regulations, increased governmental enforcement or other developments, some of which legal requirements are discussed below, could significantly increase the Company’s operational or compliance expenditures.

Remediation of subsurface contamination is in process at certain of the Company’s refinery sites and is being overseen by the appropriate state agencies. Based on current investigative and remedial activities, the Company believes that the soil and groundwater contamination at these refineries can be controlled or remediated without having a material adverse effect on the Company’s financial condition. However, such costs are often unpredictable and, therefore, there can be no assurance that the future costs will not become material.

San Antonio Refinery

In connection with the acquisition of the San Antonio refinery, the Company agreed to indemnify NuStar for an unlimited term and without consideration of a monetary deductible or cap from any environmental liabilities associated with the San Antonio refinery, except for any governmental penalties or fines that may result from NuStar’s actions or inactions during NuStar’s 20-month period of ownership of the San Antonio refinery. Anadarko Petroleum Corporation (“Anadarko”) and Age Refining, Inc. (“Age Refining”), a third party that has since entered bankruptcy, are subject to a 1995 Agreed Order from the Texas Natural Resource Conservation Commission, now known as the Texas Commission on Environmental Quality, pursuant to which Anadarko and Age Refining are obligated to assess and remediate certain contamination at the San Antonio refinery that predates the Company’s acquisition of the facility. The Company does not expect this pre-existing contamination at the San Antonio refinery to have a material adverse effect on its financial position or results of operations.

Great Falls Refinery

In connection with the acquisition of the Great Falls refinery from Connacher Oil and Gas Limited (“Connacher”), the Company became a party to an existing 2002 Refinery Initiative Consent Decree (the “Great Falls Consent Decree”) with the EPA and the Montana Department of Environmental Quality (the “MDEQ”). The material obligations imposed by the Great Falls Consent Decree have been completed. On September 27, 2012, Montana Refining Company, Inc. received a final Corrective Action Order on Consent, replacing the refinery’s previously held hazardous waste permit. This Corrective Action Order on Consent governs the investigation and remediation of contamination at the Great Falls refinery. The Company believes the majority of damages related to such contamination at the Great Falls refinery are covered by a contractual indemnity provided by HollyFrontier Corporation (“Holly”), the owner and operator of the Great Falls refinery prior to its acquisition by Connacher, under an asset purchase agreement between Holly and Connacher, pursuant to which Connacher acquired the Great Falls refinery. Under this asset purchase agreement, Holly agreed to indemnify Connacher and Montana Refining Company, Inc., subject to timely notification, certain conditions and certain monetary baskets and caps, for environmental conditions arising under Holly’s ownership and operation of the Great Falls refinery and existing as of the date of sale to Connacher. During 2014, Holly provided the Company a notice challenging the Company’s position that Holly is obligated to indemnify the Company’s remediation expenses for environmental conditions to the extent arising under Holly’s ownership and operation of the refinery and existing as of the date of sale to Connacher, which expenditures totaled approximately \$18.7 million as of June 30, 2017, of which \$14.6 million was capitalized into the cost of the Company’s recently completed refinery expansion project and \$4.1 million was expensed. The Company continues to believe that Holly is responsible to indemnify the Company for these remediation expenses disputed by Holly and on September 22, 2015, the Company initiated a lawsuit against Holly and the sellers of the Great Falls refinery under the asset purchase agreement. On November 24, 2015, Holly and the sellers of the Great Falls refinery under the asset purchase agreement filed a motion to dismiss the case pending arbitration. On February 10, 2016, the court ordered that all of the claims be addressed in arbitration. Arbitration is scheduled for early 2018. In the event the Company is unsuccessful in the legal dispute with Holly, the Company will be responsible for the remediation expenses. The Company expects that it may incur costs to remediate other environmental conditions at the Great Falls refinery; however, the costs cannot be estimated at this time. The Company believes at this time that these other costs it may incur will not be material to its financial position or results of operations.

Superior Refinery

In connection with the acquisition of the Superior refinery, the Company became a party to an existing Refinery Initiative Consent Decree ("Superior Consent Decree") with the EPA and the Wisconsin Department of Natural Resources ("WDNR") that applies, in part, to its Superior refinery. Under the Superior Consent Decree, the Company must complete certain reductions in air emissions at the Superior refinery as well as report upon certain emissions from the refinery to the EPA and the WDNR. As of June 30, 2017, the Company estimates costs of up to $6.0 million to make known equipment upgrades and conduct other discrete tasks in compliance with the Superior Consent Decree. Failure to perform these required tasks under the Superior Consent Decree could result in the imposition of stipulated penalties, which could be material. The Company is currently assessing certain past actions at the refinery for compliance with the terms of the Superior Consent Decree, which actions may be subject to stipulated penalties under the Superior Consent Decree but, in any event, the Company does not currently believe that the imposition of such penalties for those actions, should they be imposed, would be material. In addition, the Company is pursuing certain additional environmental and safety-related projects at the Superior refinery. Completion of these additional projects will result in the Company incurring additional costs, which could be substantial. For the three and six months ended June 30, 2017 and 2016, the Company incurred costs of $0.1 million and less than $0.1 million, respectively, related to installing process equipment at the Superior refinery pursuant to EPA fuel content regulations.

In June 2012, the EPA issued a Finding of Violation/Notice of Violation to the Superior refinery, which included a proposed penalty amount of $0.1 million. This finding is in response to information provided to the EPA by the Company in response to an information request. The EPA alleges that the efficiency of the flares at the Superior refinery is lower than regulatory requirements. The Company is contesting the allegations and is in settlement discussions with the EPA to resolve this issue. The Company has not yet received formal action from the EPA. The Company does not believe that the resolution of these allegations will have a material adverse effect on its financial position or results of operations.

The Company is contractually indemnified by Murphy Oil Corporation ("Murphy Oil") under an asset purchase agreement between the Company and Murphy Oil for specified environmental liabilities arising from the operation of the Superior refinery including: (i) certain obligations arising out of the Superior Consent Decree (including payment of a civil penalty required under the Superior Consent Decree), (ii) certain liabilities arising in connection with Murphy Oil's transport of certain wastes and other materials to specified offsite real properties for disposal or recycling prior to the acquisition of Superior and (iii) certain liabilities for certain third-party actions, suits or proceedings alleging exposure, prior to the acquisition of Superior, of an individual to wastes or other materials at the specified on-site real property, which wastes or other materials were spilled, released, emitted or otherwise discharged by Murphy Oil. The Company believes contractual indemnity by Murphy Oil for such specified environmental liabilities is unlimited in duration and not subject to any monetary deductibles or maximums. The amount of any damages payable by Murphy Oil pursuant to the contractual indemnities under the asset purchase agreement are net of any amount recoverable under an environmental insurance policy that the Company obtained in connection with the acquisition of the Superior refinery, which named the Company and Murphy Oil as insureds and covers environmental conditions existing at the Superior refinery prior to the Company's acquisition of the Superior refinery.

Shreveport, Cotton Valley and Princeton Refineries

On December 23, 2010, the Company entered into a settlement agreement with the Louisiana Department of Environmental Quality ("LDEQ") under LDEQ's "Small Refinery and Single Site Refinery Initiative," covering the Shreveport, Princeton and Cotton Valley refineries. This settlement agreement became effective on January 31, 2012. The settlement agreement, termed the "Global Settlement," resolved alleged violations of the federal Clean Air Act, as amended ("CAA"), and federal Clean Water Act regulations that arose prior to December 23, 2010. Among other things, the Company agreed to complete beneficial environmental programs and implement emissions reduction projects at the Company's Shreveport, Princeton and Cotton Valley refineries on an agreed-upon schedule. During the three months ended June 30, 2017, the Company incurred approximately $0.2 million of such capital expenditures. During the three months ended June 30, 2016, no such expenditures were incurred. During the six months ended June 30, 2017 and 2016, the Company incurred approximately $0.5 million and $0.4 million, respectively, of such capital expenditures. The Global Settlement is substantially complete and any remaining capital investment requirements will be incorporated into the Company's annual capital expenditures budget. The Company does not expect any additional capital expenditures included in the Global Settlement to have a material adverse effect on the Company's financial position or results of operations.

The Company is contractually indemnified by Shell Oil Company ("Shell"), as successor to Pennzoil-Quaker State Company, and Atlas Processing Company, under an asset purchase agreement between the Company and Shell, for specified environmental liabilities arising from the operations of the Shreveport refinery prior to the Company's acquisition of the facility. The Company believes the contractual indemnity is unlimited in amount and duration, but requires the Company to contribute $1.0 million of the first $5.0 million of indemnified costs for certain of the specified environmental liabilities. The Company has recorded the $1.0 million liability in the condensed consolidated balance sheets.

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Bel-Ray Facility

Bel-Ray executed an Administrative Consent Order ("ACO") with the New Jersey Department of Environmental Protection, effective January 4, 1994, which required investigation and remediation of contamination at or emanating from the Bel-Ray facility. In 2000, Bel-Ray entered into a fixed price remediation contract with Weston Solutions ("Weston"), a large remediation contractor, whereby Weston agreed to be fully liable for the remediation of the soil and groundwater issues at the facility, including an offsite groundwater plume pursuant to the ACO ("Weston Agreement"). The Weston Agreement set up a trust fund to reimburse Weston, administered by Bel-Ray's environmental counsel. As of June 30, 2017, the trust fund contained approximately $0.6 million. In addition, Weston has remediation cost containment insurance, should Weston be unable to complete the work required under the Weston Agreement. In connection with the acquisition of Bel-Ray, the Company became a party to the Weston Agreement.

Weston has been addressing the environmental issues at the Bel-Ray facility over time and the next phase will address the groundwater issues, which extend offsite.

Renewable Identification Numbers Obligation

On February 10, 2017 and on May 4, 2017, the EPA granted certain of the Company's refineries a "small refinery exemption" under the RFS for the full-year 2016, as provided for under the federal Clean Air Act, as amended ("CAA"). In granting those exemptions, the EPA determined that for the full-year 2016 compliance with the RFS would represent a "disproportionate economic hardship" for these refineries.

As of June 30, 2017 and December 31, 2016, the Company had a RINs Obligation of $25.6 million and $79.3 million, respectively. RINs gain for the three and six months ended June 30, 2017 was $16.5 million and $64.1 million, respectively, as compared to a RINs expense for the same periods in 2016 of $8.2 million and $25.0 million, respectively.

Occupational Health and Safety

The Company is subject to various laws and regulations relating to occupational health and safety, including OSHA and comparable state laws. These laws and regulations strictly govern the protection of the health and safety of employees. In addition, OSHA's hazard communication standard requires that information be maintained about hazardous materials used or produced in the Company's operations and that this information be provided to employees, contractors, state and local government authorities and customers. The Company maintains safety and training programs as part of its ongoing efforts to promote compliance with applicable laws and regulations. The Company conducts periodic audits of Process Safety Management ("PSM") systems at each of its locations subject to the PSM standard. The Company's compliance with applicable health and safety laws and regulations has required, and continues to require, substantial expenditures. Changes in occupational safety and health laws and regulations or a finding of non-compliance with current laws and regulations could result in additional capital expenditures or operating expenses, as well as civil penalties and, in the event of a serious injury or fatality, criminal charges.

In the first quarter of 2011, OSHA conducted an inspection of the Cotton Valley refinery's PSM program. On March 14, 2011, OSHA issued a Citation and Notification of Penalty (the "Cotton Valley Citation") to the Company as a result of the Cotton Valley inspection, which included a proposed penalty amount of $0.2 million. The Company has contested the Cotton Valley Citation and the parties have reached a tentative settlement with OSHA on the matter, which the Company does not believe will have a material adverse effect on its financial position or results of operations.

Legal Proceedings

The Company is subject to claims and litigation arising in the normal course of its business. The Company has recorded accruals with respect to certain of these matters, where appropriate, that are reflected in the unaudited condensed consolidated financial statements but are not individually considered material. For other matters, the Company has not recorded accruals because it has not yet determined that a loss is probable or because the amount of loss cannot be reasonably estimated. While the ultimate outcome of claims and litigation currently pending cannot be determined, the Company currently does not expect that these proceedings and claims, individually or in the aggregate (including matters for which the Company has recorded accruals), will have a material adverse effect on its financial position, results of operations or cash flows. The outcome of any litigation is inherently uncertain, however, and if decided adversely to the Company, or if the Company determines that settlement of particular litigation is appropriate, the Company may be subject to liability that could have a material adverse effect on its financial position, results of operations or cash flows.

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Standby Letters of Credit

The Company has agreements with various financial institutions for standby letters of credit, which have been issued primarily to vendors. As of June 30, 2017 and December 31, 2016, the Company had outstanding standby letters of credit of $97.1 million and $82.1 million, respectively, under its senior secured revolving credit facility (the “revolving credit facility”). Refer to Note 7 for additional information regarding the Company’s revolving credit facility. At June 30, 2017 and December 31, 2016, the maximum amount of letters of credit the Company could issue under its revolving credit facility was subject to borrowing base limitations, with a maximum letter of credit sublimit equal to $600.0 million, which amount may be increased to 90% of revolver commitments in effect ($900.0 million at June 30, 2017 and December 31, 2016) with the consent of the Agent (as defined in the revolving credit facility agreement). As of June 30, 2017 and December 31, 2016, the Company had availability to issue letters of credit of $342.1 million and $360.8 million, respectively, under its revolving credit facility.

6. Inventory Financing Agreements

On March 31, 2017, the Company entered into several agreements with Macquarie to support the operations of the Great Falls refinery (the “Great Falls Supply and Offtake Agreements”). The Great Falls Supply and Offtake Agreements expire on October 31, 2019. On July 27, 2017, the Company amended the Great Falls Supply and Offtake Agreements to provide Macquarie the option to terminate the Great Falls Supply and Offtake Agreements with nine months notice any time prior to June 2019.

On June 19, 2017, the Company entered into several agreements with Macquarie to support the operations of the Shreveport refinery (the “Shreveport Supply and Offtake Agreements”, and together with the Great Falls Supply and Offtake Agreements, the “Supply and Offtake Agreements”). The Shreveport Supply and Offtake Agreements expire on June 2020; however, Macquarie has the option to terminate the Shreveport Supply and Offtake Agreements with nine months notice any time prior to June 2019.

At the commencement of the Great Falls Supply and Offtake Agreements, the Company sold to Macquarie inventory comprised of 652,000 barrels of crude oil and refined products valued at $32.2 million.

At the commencement of the Shreveport Supply and Offtake Agreements, the Company sold to Macquarie inventory comprised of 987,000 barrels of crude oil and refined products valued at $54.8 million.

In addition, the Company incurred approximately $3.0 million of costs related to the Supply and Offtake Agreements. These capitalized costs are recorded in obligations under inventory financing agreements in the Company’s condensed consolidated balance sheets and amortized to interest expense over the term of the agreement.

During the terms of the Supply and Offtake Agreements, the Company may purchase crude oil from Macquarie or one of its affiliates. Per the Supply and Offtake Agreements, Macquarie will provide up to 30,000 barrels per day of crude oil to the Great Falls refinery and 60,000 barrels per day of crude oil to the Shreveport refinery. The Company agreed to purchase the crude oil on a just-in-time basis to support the production operations at the Great Falls and Shreveport refineries. Additionally, the Company agreed to sell, and Macquarie agreed to buy, at market prices, refined products produced at the Great Falls and Shreveport refineries. For Shreveport finished products consisting of finished fuel products (other than jet fuel), lubricants and waxes, Macquarie may (but is not required to) sell such products to the sales intermediation party (“SIP”), and the SIP may (but is not required to) sell such products to Shreveport, as applicable, for sale in turn to third parties. For jet fuel and certain intermediate products, Macquarie may (but is not required to) sell such products to Shreveport for sale thereby to third parties. The Company will then repurchase the refined products from Macquarie or the SIP prior to selling the refined products to third parties.

The Supply and Offtake Agreements are subject to minimum and maximum inventory levels. The agreements also provide for the lease to Macquarie of crude oil and certain refined product storage tanks located at the Great Falls and Shreveport refineries and certain offsite locations. Following expiration or termination of the agreements, Macquarie has the option to require the Company to purchase the crude oil and refined product inventories then owned by Macquarie and located at the leased storage tanks at then current market prices. In addition, barrels owned by the Company are pledged as collateral to support the Deferred Payment Arrangement (defined below) obligations under these agreements.

While title to certain inventories will reside with Macquarie, the Supply and Offtake Agreements are accounted for by the Company similar to a product financing arrangement; therefore, the inventories sold to Macquarie will continue to be included in the Company's condensed consolidated balance sheets until processed and sold to a third party. Each reporting period, the Company will record liabilities in an amount equal to the amount the Company expects to pay to repurchase the inventory held by Macquarie based on market prices at the termination date included in obligations under inventory financing agreements in the condensed consolidated balance sheets. The Company has determined that the redemption feature on the initially recognized liabilities related to the Supply and Offtake Agreements and the contingent interest feature are embedded derivatives indexed to commodity prices. As such, the Company has accounted for these embedded derivatives at fair value with changes in the fair value, if any, recorded in gain (loss) on derivative instruments in the Company's unaudited condensed consolidated statements of operations. For more information on the valuation of the associated derivatives, see Note 8 - "Derivatives" and Note 9 - "Fair Value Measurements."

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The embedded derivatives will be recorded in obligations under inventory financing agreements on the condensed consolidated balance sheets. The cash flow impact of the embedded derivatives will be classified as a change in derivative activity in the financing activities section in the unaudited condensed consolidated statements of cash flows. For the three and six months ended June 30, 2017, the Company incurred $0.4 million of financing costs related to the Supply and Offtake Agreements, which is included in interest expense in the Company's unaudited condensed consolidated statements of operations.

The Company has provided collateral of $5.0 million related to the initial purchase of Great Falls and Shreveport inventory to cover credit risk for future crude oil deliveries and potential liquidation risk if Macquarie exercises its rights and sells the inventory to third parties. The collateral was recorded as a reduction to the obligations under inventory financing agreements pursuant to a master netting agreement.

The Supply and Offtake Agreements also include a deferred payment arrangement ("Deferred Payment Arrangement") whereby the Company can defer payments on just-in-time crude oil purchases from Macquarie owed under the agreements up to the value of the collateral provided (90.0% of the collateral inventory) with the amount due always paid prior to the 20th of the month. The deferred amounts under the deferred payment arrangement will bear interest at a rate equal to LIBOR plus 3.25% or 2.65% per annum for Shreveport and Great Falls, respectively. Amounts outstanding under the Deferred Payment Arrangement are included in obligations under inventory financing agreements in the Company's condensed consolidated balance sheets. Changes in the amount outstanding under the Deferred Payment Arrangement are included within cash flows from financing activities on the unaudited condensed consolidated statements of cash flows. As of June 30, 2017, the capacity of the Deferred Payment Arrangement was $16.3 million and the Company had $15.1 million deferred payments outstanding.

7. Long-Term Debt

Long-term debt consisted of the following (in millions):

	June 30, 2017	December 31, 2016
Borrowings under amended and restated senior secured revolving credit agreement with third-party lenders, interest payments quarterly, borrowings due July 2019, weighted average interest rate of 6.1% and 4.8% for the six months ended June 30, 2017 and year ended December 31, 2016, respectively	$0.4	$ 10.2
Borrowings under 2021 Secured Notes, interest at a fixed rate of 11.50%, interest payments semiannually, borrowings due January 2021, effective interest rate of 12.3% and 12.2% for the six months ended June 30, 2017 and year ended December 31, 2016, respectively.	400.0	400.0
Borrowings under 2021 Notes, interest at a fixed rate of 6.50%, interest payments semiannually, borrowings due April 2021, effective interest rate of 6.8% for the six months ended June 30, 2017 and year ended December 31, 2016.	900.0	900.0
Borrowings under 2022 Notes, interest at a fixed rate of 7.625%, interest payments semiannually, borrowings due January 2022, effective interest rate of 8.0% for the six months ended June 30, 2017 and year ended December 31, 2016. (1)	352.3	352.5
Borrowings under 2023 Notes, interest at a fixed rate of 7.75%, interest payments semiannually, borrowings due April 2023, effective interest rate of 8.0% for the six months ended June 30, 2017 and year ended December 31, 2016.	325.0	325.0
Other	7.3	8.0
Capital lease obligations, at various interest rates, interest and principal payments monthly through November 2034	45.2	46.5
Less unamortized debt issuance costs (2)	(29.6)	(33.2)
Less unamortized discounts	(10.8)	(11.8)
Total long-term debt	$1,989.8	$ 1,997.2
Less current portion of long-term debt	3.4	3.5
	$1,986.4	$ 1,993.7

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(1) The balance includes a fair value interest rate hedge adjustment, which increased the debt balance by $2.3 million and $2.5 million as of June 30, 2017 and December 31, 2016, respectively (refer to Note 8 for additional information on the interest rate swap designated as a fair value hedge).

(2) Deferred debt issuance costs are being amortized by the effective interest rate method over the lives of the related debt instruments. These amounts are net of accumulated amortization of $18.0 million and $14.5 million at June 30, 2017 and December 31, 2016, respectively.

Senior Notes

11.50% Senior Secured Notes (the “2021 Secured Notes”)

On April 20, 2016, the Company issued and sold $400.0 million in aggregate principal amount of 11.50% Senior Secured Notes due January 15, 2021, in a private placement pursuant to Section 4(a)(2) of the Securities Act of 1933, as amended (the “Securities Act”), to eligible purchasers at a discounted price of 98.273 percent of par. Subject to certain exceptions, the 2021 Secured Notes are secured by a lien on all of the fixed assets that secure the Company’s obligations under its secured hedge agreements, including certain present and future real property, fixtures and equipment; all U.S. registered patents and patent license rights, trademarks and trademark license rights, copyrights and copyright license rights and trade secrets; chattel paper, documents and instruments; certain cash deposits in the property, plant and equipment proceeds account; certain books and records; and all accessions and proceeds of any of the foregoing. The Company received net proceeds of approximately $382.5 million net of discount, initial purchasers’ fees and estimated expenses, which it used to repay borrowings outstanding under its revolving credit facility and for general partnership purposes, including planned capital expenditures at its facilities and working capital. Interest on the 2021 Secured Notes is paid semiannually in arrears on January 15 and July 15 of each year, beginning on July 15, 2016.

7.75% Senior Notes (the “2023 Notes”)

On March 27, 2015, the Company issued and sold $325.0 million in aggregate principal amount of 7.75% Senior Notes due April 15, 2023, in a private placement pursuant to Section 4(a)(2) of the Securities Act, to eligible purchasers at a discounted price of 99.257 percent of par. The Company received net proceeds of approximately $317.0 million net of discount, initial purchasers’ fees and expenses, which the Company used to fund the redemption of $178.8 million in aggregate principal amount of outstanding 9.625% senior notes due 2020 on April 28, 2015, to repay borrowings outstanding under its revolving credit facility and for general partnership purposes, including planned capital expenditures at the Company’s facilities and working capital. Interest on the 2023 Notes is paid semiannually in arrears on April 15 and October 15 of each year, beginning on October 15, 2015.

6.50% Senior Notes (the “2021 Notes”)

On March 31, 2014, the Company issued and sold $900.0 million in aggregate principal amount of 6.50% Senior Notes due April 15, 2021, in a private placement pursuant to Section 4(a)(2) of the Securities Act, to eligible purchasers at par. The Company received net proceeds of approximately $884.0 million net of initial purchasers’ fees and expenses, which the Company used to fund the purchase price of ADF Holdings, Inc., the parent company of Anchor Drilling Fluids USA, Inc. (subsequently converted to ADF Holdings, LLC and Anchor Drilling Fluids USA, LLC), the redemption of $500.0 million in aggregate principal amount outstanding of 9.375% Senior Notes due 2019 and for general partnership purposes, including planned capital expenditures at the Company’s facilities. Interest on the 2021 Notes is paid semiannually in arrears on April 15 and October 15 of each year, beginning on October 15, 2014.

7.625% Senior Notes (the “2022 Notes”)

On November 26, 2013, the Company issued and sold $350.0 million in aggregate principal amount of 7.625% Senior Notes due January 15, 2022, in a private placement pursuant to Section 4(a)(2) of the Securities Act, to eligible purchasers at a discounted price of 98.494 percent of par. The Company received net proceeds of approximately $337.4 million, net of discount, initial purchasers’ fees and expenses, which the Company used for general partnership purposes, to fund previously announced organic growth projects, the purchase price of the Bel-Ray acquisition and the redemption of $100.0 million in aggregate principal amount outstanding of 9.375% Senior Notes due 2019. Interest on the 2022 Notes is paid semiannually in arrears on January 15 and July 15 of each year, beginning on July 15, 2014.

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2021 Secured Notes, 2021 Notes, 2022 Notes and 2023 Notes

In accordance with SEC Rule 3-10 of Regulation S-X, unaudited condensed consolidated financial statements of non-guarantors are not required. The Company has no assets or operations independent of its subsidiaries. Obligations under its 2021, 2022 and 2023 Notes are fully and unconditionally and jointly and severally guaranteed on a senior unsecured basis by the Company's current 100%-owned operating subsidiaries and certain of the Company's future operating subsidiaries, with the exception of the Company's "minor" subsidiaries (as defined by Rule 3-10 of Regulation S-X), including Calumet Finance Corp. (100%-owned Delaware corporation that was organized for the sole purpose of being a co-issuer of certain of the Company's indebtedness, including the 2021 Secured, 2021, 2022 and 2023 Notes). There are no significant restrictions on the ability of the Company or subsidiary guarantors for the Company to obtain funds from its subsidiary guarantors by dividend or loan. None of the subsidiary guarantors' assets represent restricted assets pursuant to SEC Rule 4-08(e)(3) of Regulation S-X.

The 2021 Secured, 2021, 2022 and 2023 Notes are subject to certain automatic customary releases, including the sale, disposition or transfer of capital stock or substantially all of the assets of a subsidiary guarantor, designation of a subsidiary guarantor as unrestricted in accordance with the applicable indenture, exercise of legal defeasance option or covenant defeasance option, liquidation or dissolution of the subsidiary guarantor and a subsidiary guarantor ceases to both guarantee other Company debt and to be an obligor under the revolving credit facility. The Company's operating subsidiaries may not sell or otherwise dispose of all or substantially all of their properties or assets to, or consolidate with or merge into, another company if such a sale would cause a default under the indentures governing the 2021 Secured, 2021, 2022 and 2023 Notes.

The indentures governing the 2021 Secured, 2021, 2022 and 2023 Notes contain covenants that, among other things, restrict the Company's ability and the ability of certain of the Company's subsidiaries to: (i) sell assets; (ii) pay distributions on, redeem or repurchase the Company's common units or redeem or repurchase its subordinated debt or, in the case of the 2021 Secured Notes, its unsecured notes; (iii) make investments; (iv) incur or guarantee additional indebtedness or issue preferred units; (v) create or incur certain liens; (vi) enter into agreements that restrict distributions or other payments from the Company's restricted subsidiaries to the Company; (vii) consolidate, merge or transfer all or substantially all of the Company's assets; (viii) engage in transactions with affiliates and (ix) create unrestricted subsidiaries. These covenants are subject to important exceptions and qualifications. At any time when the 2021 Secured, 2021, 2022 and 2023 Notes are rated investment grade by either Moody's Investors Service, Inc. ("Moody's") or S&P Global Ratings ("S&P") and no Default or Event of Default, each as defined in the indentures governing the 2021 Secured, 2021, 2022 and 2023 Notes, has occurred and is continuing, many of these covenants will be suspended. As of June 30, 2017, the Company's Fixed Charge Coverage Ratio (as defined in the indentures governing the 2021 Secured, 2021, 2022 and 2023 Notes) was 1.5 to 1.0. As of June 30, 2017, the Company was in compliance with all covenants under the indentures governing the 2021 Secured, 2021, 2022 and 2023 Notes.

Second Amended and Restated Senior Secured Revolving Credit Facility

The Company has a $900.0 million senior secured revolving credit facility, subject to borrowing base limitations, which includes a $500.0 million incremental uncommitted expansion feature. The revolving credit facility is the Company's primary source of liquidity for cash needs in excess of cash generated from operations. The revolving credit facility matures in July 2019 and currently bears interest at a rate equal to either the prime rate plus a basis points margin or the London Interbank Offered Rate ("LIBOR") plus a basis points margin, at the Company's option. As of June 30, 2017, the margin was 50 basis points for prime rate loans and 150 basis points for LIBOR rate loans; however, the margin can fluctuate quarterly based on the Company's average availability for additional borrowings under the revolving credit facility in the preceding fiscal quarter.

On March 31, 2017, the Company amended its revolving credit facility to allow for the entry into the Supply and Offtake Agreements at the Great Falls refinery. The amendment resulted in the release of certain Eligible Inventory (as defined in the revolving credit facility agreement) from the revolving credit facility as that inventory is now collateral under the Supply and Offtake Agreements. For additional discussion of the Supply and Offtake Agreements, refer to Note 6.

In addition to paying interest quarterly on outstanding borrowings under the revolving credit facility, the Company is required to pay a commitment fee to the lenders under the revolving credit facility with respect to the unutilized

commitments thereunder at a rate equal to 0.250% or 0.375% per annum, depending on the average daily available unused borrowing capacity for the preceding month. The Company also pays a customary letter of credit fee, including a fronting fee of 0.125% per annum of the stated amount of each outstanding letter of credit and customary agency fees.
The borrowing capacity as of June 30, 2017 under the revolving credit facility was $439.6 million. As of June 30, 2017, the Company had $0.4 million in outstanding borrowings under the revolving credit facility and outstanding standby letters of credit of $97.1 million, leaving $342.1 million available for additional borrowings based on specified availability limitations. Lenders under the revolving credit facility have a first priority lien on the Company’s accounts receivable, certain inventory and substantially all of its cash (collectively, the “Credit Agreement Collateral”). The revolving credit facility contains various covenants that limit, among other things, the Company’s ability to: incur indebtedness; grant liens; dispose of certain assets; make certain acquisitions and investments; redeem or prepay other debt or

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make other restricted payments such as distributions to unitholders; enter into transactions with affiliates and enter into a merger, consolidation or sale of assets. Further, the revolving credit facility contains one springing financial covenant which provides that only if the Company's availability under the revolving credit facility falls below the greater of (a) 12.5% of the Borrowing Base (as defined in the revolving credit agreement) then in effect and (b) $45.0 million (which amount is subject to increase in proportion to revolving commitment increases), then the Company will be required to maintain as of the end of each fiscal quarter a Fixed Charge Coverage Ratio (as defined in the revolving credit agreement) of at least 1.0 to 1.0.

As of June 30, 2017, the Company was in compliance with all covenants under the revolving credit facility.

Maturities of Long-Term Debt

As of June 30, 2017, principal payments on debt obligations and future minimum rentals on capital lease obligations are as follows (in millions):

Year	Maturity
2017	$1.7
2018	4.2
2019	3.2
2020	2.4
2021	1,303.3
Thereafter	713.1
Total	$2,027.9

8. Derivatives

The Company is exposed to price risks due to fluctuations in the price of crude oil, refined products (primarily in the Company's fuel products segment), natural gas and precious metals. The Company uses various strategies to reduce its exposure to commodity price risk. The strategies to reduce the Company's risk utilize both physical forward contracts and financially settled derivative instruments, such as swaps, collars, options and futures, to attempt to reduce the Company's exposure with respect to:

- crude oil purchases and sales;
- fuel product sales and purchases;
- natural gas purchases;
- precious metals purchases; and
- fluctuations in the value of crude oil between geographic regions and between the different types of crude oil such as New York Mercantile Exchange West Texas Intermediate ("NYMEX WTI"), Light Louisiana Sweet ("LLS"), Western Canadian Select ("WCS"), Mixed Sweet Blend ("MSW") and ICE Brent.

The Company manages its exposure to commodity markets, credit, volumetric and liquidity risks to manage its costs and volatility of cash flows as conditions warrant or opportunities become available. These risks may be managed in a variety of ways that may include the use of derivative instruments. Derivative instruments may be used for the purpose of mitigating risks associated with an asset, liability and anticipated future transactions and the changes in fair value of the Company's derivative instruments will affect its earnings and cash flows; however, such changes should be offset by price or rate changes related to the underlying commodity or financial transaction that is part of the risk management strategy. The Company does not speculate with derivative instruments or other contractual arrangements that are not associated with its business objectives. Speculation is defined as increasing the Company's natural position above the maximum position of its physical assets or trading in commodities, currencies or other risk bearing assets that are not associated with the Company's business activities and objectives. The Company's positions are monitored routinely by a risk management committee to maintain compliance with its stated risk management policy and documented risk management strategies. All strategies are reviewed on an ongoing basis by the Company's risk management committee, which will add, remove or revise strategies in anticipation of changes in market conditions and/or its risk profiles. Such changes in strategies are to position the Company in relation to its risk exposures in an attempt to capture market opportunities as they arise.

The Company is obligated to repurchase crude oil and refined products from Macquarie at the termination of the Supply and Offtake Agreements in certain scenarios. The Company has determined that the redemption feature on the initially recognized liability related to the Supply and Offtake Agreements and the contingent interest feature are embedded derivatives indexed to commodity prices. As such, the Company has accounted for these embedded derivatives at fair value with changes in the fair value, if any, recorded in gain (loss) on derivative instruments in the Company's unaudited condensed consolidated statements of operations.

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The Company recognizes all derivative instruments at their fair values (see Note 9) as either current assets or current liabilities in the condensed consolidated balance sheets. Fair value includes any premiums paid or received and unrealized gains and losses. Fair value does not include any amounts receivable from or payable to counterparties, or collateral provided to counterparties. Derivative asset and liability amounts with the same counterparty are netted against each other for financial reporting purposes.

The following tables summarize the Company's gross fair values of its derivative instruments, presenting the impact of offsetting derivative assets in the Company's condensed consolidated balance sheets as of June 30, 2017, and December 31, 2016 (in millions):

	Balance Sheet Location	June 30, 2017			December 31, 2016		
		Gross Amounts of Recognized Assets	Gross Amounts Offset in the Condensed Consolidated Balance Sheets	Net Amounts of Assets Presented in the Condensed Consolidated Balance Sheets	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Condensed Consolidated Balance Sheets	Net Amounts of Assets Presented in the Condensed Consolidated Balance Sheets
Derivative instruments not designated as hedges:							
Specialty products segment:							
Natural gas swaps	Derivative assets	$—	$ (0.8)	$ (0.8)	$0.1	$ (0.1)	$ —
Fuel products segment:							
Crude oil swaps	Derivative assets	1.2	(2.1)	(0.9)	10.3	(7.4)	2.9
Crude oil basis swaps	Derivative assets	2.2	0.1	2.3	—	(2.1)	(2.1)
Crude oil percentage basis swaps	Derivative assets	0.8	(0.4)	0.4	0.1	(0.1)	—
Total derivative instruments		$4.2	$ (3.2)	$ 1.0	$10.5	$ (9.7)	$ 0.8

The following tables summarize the Company's gross fair values of its derivative instruments, presenting the impact of offsetting derivative liabilities in the Company's condensed consolidated balance sheets as of June 30, 2017, and December 31, 2016 (in millions):

	Balance Sheet Location	June 30, 2017			December 31, 2016		
		Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Condensed Consolidated Balance Sheets	Net Amounts of Liabilities Presented in the Condensed Consolidated Balance Sheets	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Condensed Consolidated Balance Sheets	Net Amounts of Liabilities Presented in the Condensed Consolidated Balance Sheets
Derivative instruments not designated as hedges:							
Specialty products segment:							
Natural gas swaps	Derivative liabilities	$(1.6)	$ 0.8	$ (0.8)	$(1.2)	$ 0.1	$ (1.1)
Fuel products segment:							
Inventory financing obligation	Obligations under inventory financing agreements	(0.9)	—	(0.9)	—	—	—

Crude oil swaps	Derivative liabilities	(3.8)	2.1	(1.7)	(8.2)	7.4	(0.8)
Crude oil basis swaps	Derivative liabilities	0.1	(0.1)	—	(7.1)	2.1	(5.0)
Crude oil percentage basis swaps	Derivative liabilities	—	0.4	0.4	(0.6)	0.1	(0.5)
Gasoline crack spread swaps	Derivative liabilities	—	—	—	(3.5)	—	(3.5)
Diesel crack spread swaps	Derivative liabilities	—	—	—	(1.4)	—	(1.4)
2/1/1 crack spread swaps	Derivative liabilities	—	—	—	(2.5)	—	(2.5)
Total derivative instruments		$(6.2)	$ 3.2	$ (3.0)	$(24.5)	$ 9.7	$ (14.8)

The Company is exposed to credit risk in the event of nonperformance by its counterparties on these derivative transactions. The Company does not expect nonperformance on any derivative instruments, however, no assurances can be provided. The Company's

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credit exposure related to these derivative instruments is represented by the fair value of contracts reported as derivative assets. As of June 30, 2017, the Company had three counterparties in which the derivatives held were net assets, totaling $1.0 million. As of December 31, 2016, the Company had one counterparty in which the derivatives held were net assets, totaling $0.8 million. To manage credit risk, the Company selects and periodically reviews counterparties based on credit ratings. The Company primarily executes its derivative instruments with large financial institutions that have ratings of at least Baa2 and BBB+ by Moody’s and S&P, respectively. In the event of default, the Company would potentially be subject to losses on derivative instruments with mark-to-market gains. The Company requires collateral from its counterparties when the fair value of the derivatives exceeds agreed-upon thresholds in its master derivative contracts with these counterparties. No such collateral was held by the Company as of June 30, 2017 or December 31, 2016. Collateral received from counterparties is reported in other current liabilities, and collateral held by counterparties is reported in prepaid expenses and other current assets on the Company’s condensed consolidated balance sheets and is not netted against derivative assets or liabilities. Any outstanding collateral is released to the Company upon settlement of the related derivative instrument liability. As of June 30, 2017 and December 31, 2016, the Company had provided no collateral to its counterparties.

Certain of the Company’s outstanding derivative instruments are subject to credit support agreements with the applicable counterparties which contain provisions setting certain credit thresholds above which the Company may be required to post agreed-upon collateral, such as cash or letters of credit, with the counterparty to the extent that the Company’s mark-to-market net liability, if any, on all outstanding derivatives exceeds the credit threshold amount per such credit support agreement. The majority of the credit support agreements covering the Company’s outstanding derivative instruments also contain a general provision stating that if the Company experiences a material adverse change in its business, in the reasonable discretion of the counterparty, the Company’s credit threshold could be lowered by such counterparty. The Company does not expect that it will experience a material adverse change in its business.

The cash flow impact of the Company’s commodity derivative activities is classified primarily as a change in derivative activity in the operating activities section in the unaudited condensed consolidated statements of cash flows. The cash flow impact of the Company’s embedded derivatives included in the Supply and Offtake Agreements is classified as a change in derivative activity in the investing activities section in the unaudited condensed consolidated statements of cash flows.

Derivative Instruments Designated as Cash Flow Hedges

Prior to 2017, the Company accounted for certain derivatives hedging purchases of crude oil and sales of diesel swaps as cash flow hedges. As of June 30, 2017, the Company has no derivative instruments designated as cash flow hedges. The derivative instruments designated as cash flow hedges that are hedging sales and purchases are recorded to sales and cost of sales, respectively, in the unaudited condensed consolidated statements of operations upon recording the related hedged transaction in sales or cost of sales. The Company assesses, both at inception of the cash flow hedge and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items. Periodically, the Company may enter into crude oil and fuel product basis swaps to more effectively hedge its crude oil purchases, crude oil sales and fuel products sales. These derivatives can be combined with a swap contract in order to create a more effective cash flow hedge.

To the extent a derivative instrument designated as a cash flow hedge is determined to be effective as a cash flow hedge of an exposure to changes in the fair value of a future transaction, the change in fair value of the derivative is deferred in accumulated other comprehensive income (loss), a component of partners’ capital in the condensed consolidated balance sheets, until the underlying transaction hedged is recognized in the unaudited condensed consolidated statements of operations.

Ineffectiveness is inherent in the hedging of crude oil and fuel products. Due to the volatility in the markets for crude oil and fuel products, the Company is unable to predict the amount of ineffectiveness each period, determined on a derivative by derivative basis or in the aggregate for a specific commodity and has the potential for the future loss of cash flow hedge accounting. Ineffectiveness has resulted, and the loss of cash flow hedge accounting has resulted, in increased volatility in the Company’s financial results. However, even though certain derivative instruments may not qualify for cash flow hedge accounting, the Company intends to continue to utilize such instruments as management believes such derivative instruments continue to provide the Company with the opportunity to more effectively stabilize cash flows.

Cash flow hedge accounting is discontinued when it is determined that a derivative no longer qualifies as an effective hedge or when it is no longer probable that the hedged forecasted transaction will occur. When cash flow hedge accounting is discontinued because the derivative instrument no longer qualifies as an effective cash flow hedge, the derivative instrument is subject to the mark-to-market method of accounting prospectively. Changes in the mark-to-market fair value of the derivative instrument are recorded to gain (loss) on derivative instruments in the unaudited condensed consolidated statements of operations. Unrealized gains and losses related to discontinued cash flow hedges that were previously deferred in accumulated other comprehensive income (loss) will remain in accumulated other comprehensive income (loss) until the underlying transaction is reflected in earnings, unless it is probable that the hedged forecasted transaction will not occur, at which time, associated deferred amounts in accumulated other comprehensive income (loss) are immediately recognized in gain (loss) on derivative instruments in the unaudited condensed consolidated statements of operations.

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The Company recorded the following amounts in its condensed consolidated balance sheets, unaudited condensed consolidated statements of operations, unaudited condensed consolidated statements of comprehensive loss and unaudited condensed consolidated statements of partners' capital as of and for the three months ended June 30, 2017 and 2016, related to its derivative instruments that were designated as cash flow hedges (in millions):

Type of Derivative	Amount of Gain (Loss) Recognized in Accumulated Other Comprehensive Loss on Derivatives (Effective Portion)		Amount of Gain (Loss) Reclassified from Accumulated Other Comprehensive Loss into Net Income (Loss) (Effective Portion)			Amount of Gain (Loss) Recognized in Net Income (Loss) on Derivatives (Ineffective Portion)		
	Three Months Ended June 30,		Location of Gain (Loss)	Three Months Ended June 30,		Location of Gain (Loss)	Three Months Ended June 30,	
	2017	2016		2017	2016		2017	2016
Specialty products segment:								
Crude oil swaps	$ —	$ —	Cost of sales	$ —	$ (0.5)	Gain (loss) on derivative instruments	$ —	$ —
Fuel products segment:								
Crude oil swaps	—	(4.5)	Cost of sales	—	(12.3)	Gain (loss) on derivative instruments	—	—
Diesel swaps	—	4.5	Sales	—	15.1	Gain (loss) on derivative instruments	—	—
Total	$ —	$ —		$ —	$ 2.3		$ —	$ —

The Company recorded the following amounts in its condensed consolidated balance sheets, unaudited condensed consolidated statements of operations, unaudited condensed consolidated statements of comprehensive income (loss) and unaudited condensed consolidated statements of partners' capital as of and for the six months ended June 30, 2017 and 2016, related to its derivative instruments that were designated as cash flow hedges (in millions):

Type of Derivative	Amount of Gain (Loss) Recognized in Accumulated Other Comprehensive Loss on Derivatives (Effective Portion)		Amount of Gain (Loss) Reclassified from Accumulated Other Comprehensive Loss into Net Income (Loss) (Effective Portion)			Amount of Gain (Loss) Recognized in Net Income (Loss) on Derivatives (Ineffective Portion)		
	Six Months Ended June 30,		Location of Gain (Loss)	Six Months Ended June 30,		Location of Gain (Loss)	Six Months Ended June 30,	
	2017	2016		2017	2016		2017	2016

Specialty products segment:								
Crude oil swaps	$ —	$ —	Cost of sales	$ —	$ (1.2)	Gain (loss) on derivative instruments	$ —	$ —
Fuel products segment:								
Crude oil swaps	—	(5.8)	Cost of sales	—	(25.5)	Gain (loss) on derivative instruments	—	—
Diesel swaps	—	5.8	Sales	—	31.1	Gain (loss) on derivative instruments	—	—
Total	$ —	$ —		$ —	$ 4.4		$ —	$ —

As of June 30, 2017 and December 31, 2016, there was no effective portion of cash flow hedges classified in accumulated other comprehensive loss.

Derivative Instruments Designated as Fair Value Hedges

For derivative instruments that are designated and qualify as a fair value hedge (which are limited to interest rate swaps), the effective gain or loss on the derivative instrument, as well as the offsetting gain or loss on the hedged item attributable to the hedged risk are recognized as interest expense in the unaudited condensed consolidated statements of operations. No hedge ineffectiveness is recognized if the interest rate swap qualifies for the “shortcut” method and, as a result, changes in the fair value of the derivative instrument offset the changes in the fair value of the underlying hedged debt. In addition, the differential to be paid or received on the interest rate swap arrangement is accrued and recognized as an adjustment to interest expense in the unaudited condensed consolidated statements of operations. The Company assesses at the inception of the fair value hedge whether the derivatives that are used in the hedging transactions are highly effective in offsetting changes in fair values of hedged items.

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Fair value hedge accounting is discontinued when it is determined that a derivative no longer qualifies as an effective hedge or when it is no longer probable that the hedged forecasted transaction will occur. When fair value hedge accounting is discontinued because the derivative instrument no longer qualifies as an effective fair value hedge, the derivative instrument is still subject to mark-to-market method of accounting, however the Company will cease to adjust the hedged asset or liability for changes in fair value.

In 2014, the Company entered into an interest rate swap agreement which converted a portion of the Company's fixed rate debt to a floating rate. This agreement involved the receipt of fixed rate amounts in exchange for floating rate interest payments over the life of the agreement without an exchange of the underlying principal amount. Also, in connection with the interest rate swap agreement, the Company entered into an option that permits the counterparty to cancel the interest rate swap for a specified premium. The Company designated this interest rate swap and option as a fair value hedge. On January 13, 2015, the Company terminated its interest rate swap, which was designated as a fair value hedge, related to a notional amount of $200.0 million of 2022 Notes. In settlement of this swap, the Company recognized a net gain of approximately $3.3 million.

The Company recorded the following losses in its unaudited condensed consolidated statements of operations for the three and six months ended June 30, 2017 and 2016, related to its derivative instrument designated as a fair value hedge (in millions):

	Location of Loss of Derivative	Amount of Gain Recognized in Net Income (Loss) Three Months Ended June 30,		Six Months Ended June 30,		Hedged Item	Location of Gain on Hedged Item	Amount of Gain Recognized in Net Income (Loss) Three Months Ended June 30,		Six Months Ended June 30,	
		2017	2016	2017	2016			2017	2016	2017	2016
Swaps not allocated to a specific segment:											
Interest rate swap	Interest expense	$0.1	$0.1	$0.2	$0.2	2022 Notes	Interest income	$ —	$ —	$ —	$ —
Total		$0.1	$0.1	$0.2	$0.2			$ —	$ —	$ —	$ —

Derivative Instruments Not Designated as Hedges

For derivative instruments not designated as hedges, the change in fair value of the asset or liability for the period is recorded to gain (loss) on derivative instruments in the unaudited condensed consolidated statements of operations. Upon the settlement of a derivative not designated as a hedge, the gain or loss at settlement is realized in the unaudited condensed consolidated statements of operations in gain (loss) on derivative instruments. Additionally, the Company has entered into natural gas swaps and certain other crude oil swaps that do not qualify as cash flow hedges for accounting purposes as they are determined not to be highly effective in offsetting changes in the cash flows associated with crude oil purchases and natural gas purchases and gasoline and diesel sales at the Company's refineries.

The Company recorded the following gains (losses) in its unaudited condensed consolidated statements of operations for the three months ended June 30, 2017 and 2016, related to its derivative instruments not designated as hedges (in millions):

Type of Derivative	Amount of Realized Gain (Loss) Recognized in Gain (Loss) on Derivative Instruments Three Months Ended June 30,	Amount of Unrealized Gain (Loss) Recognized in Gain (Loss) on Derivative Instruments Three Months Ended June 30,

	2017	2016	2017	2016
Specialty products segment:				
Natural gas swaps	$ (0.9)	$ (3.2)	$ 0.2	$ 6.6
Natural gas collars	—	(0.4)	—	0.5
Fuel products segment:				
Inventory financing obligation	—	—	(0.9)	—
Crude oil swaps	(1.1)	0.1	(1.5)	11.5
Crude oil basis swaps	1.4	0.1	3.2	(2.3)
Crude oil percentage basis swaps	0.6	(0.5)	0.3	5.2
Crude oil options	—	(1.5)	—	0.8
Natural gas swaps	—	(0.6)	—	1.5
Total	$ —	$ (6.0)	$ 1.3	$ 23.8

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The Company recorded the following gains (losses) in its unaudited condensed consolidated statements of operations for the six months ended June 30, 2017 and 2016, related to its derivative instruments not designated as hedges (in millions):

Type of Derivative	Amount of Realized Loss Recognized in Gain (Loss) on Derivative Instruments		Amount of Unrealized Gain (Loss) Recognized in Gain (Loss) on Derivative Instruments	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Specialty products segment:				
Natural gas swaps	$ (1.7)	$ (6.6)	$ (0.6)	$ 8.5
Natural gas collars	—	(0.7)	—	0.6
Fuel products segment:				
Inventory financing obligation	—	—	(0.9)	—
Crude oil swaps	(1.5)	(0.8)	(4.8)	13.0
Crude oil basis swaps	0.6	0.1	9.4	(4.9)
Crude oil percentage basis swaps	0.6	(4.4)	1.3	5.4
Crude oil options	—	(1.5)	—	0.2
Crude oil futures	—	(2.0)	—	—
Gasoline crack spread swaps	(1.6)	(1.2)	4.8	4.3
Diesel crack spread swaps	(0.3)	—	2.7	—
2/1/1 crack spread swaps	(1.0)	—	—	—
Natural gas swaps	—	(1.2)	—	1.3
Total	$ (4.9)	$ (18.3)	$ 11.9	$ 28.4

Derivative Positions — Specialty Products Segment

Natural Gas Swap Contracts

At June 30, 2017, the Company had the following derivatives related to natural gas purchases in its specialty products segment, none of which are designated as hedges:

Natural Gas Swap Contracts by Expiration Dates	MMBtu	$/MMBtu
Third Quarter 2017	1,320,000	$ 3.87
Fourth Quarter 2017	960,000	$ 3.72
Total	2,280,000	
Average price		$ 3.81

At December 31, 2016, the Company had the following derivatives related to natural gas purchases in its specialty products segment, none of which are designated as hedges:

Natural Gas Swap Contracts by Expiration Dates	MMBtu	$/MMBtu
First Quarter 2017	1,350,000	$ 3.88
Second Quarter 2017	1,320,000	$ 3.87
Third Quarter 2017	1,320,000	$ 3.87
Fourth Quarter 2017	960,000	$ 3.72
Total	4,950,000	
Average price		$ 3.85

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Derivative Positions — Fuel Products Segment

Crude Oil Swap Contracts

At June 30, 2017, the Company had the following derivatives related to crude oil purchases in its fuel products segment, none of which are designated as hedges:

Crude Oil Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Swap ($/Bbl)
Third Quarter 2017	327,161	3,556	$ 48.87
Fourth Quarter 2017	327,161	3,556	$ 48.87
Total	654,322		
Average price			$ 48.87

At June 30, 2017, the Company had the following derivatives related to crude oil sales in its fuel products segment, none of which are designated as hedges:

Crude Oil Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
Third Quarter 2017	133,216	1,448	$ 41.56
Fourth Quarter 2017	133,216	1,448	$ 41.56
Total	266,432		
Average price			$ 41.56

At December 31, 2016, the Company had the following derivatives related to crude oil purchases in its fuel products segment, none of which are designated as hedges:

Crude Oil Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Swap ($/Bbl)
First Quarter 2017	320,049	3,556	$ 48.87
Second Quarter 2017	323,605	3,556	$ 48.87
Third Quarter 2017	327,161	3,556	$ 48.87
Fourth Quarter 2017	327,161	3,556	$ 48.87
Total	1,297,976		
Average price			$ 48.87

At December 31, 2016, the Company had the following derivatives related to crude oil sales in its fuel products segment, none of which are designated as hedges:

Crude Oil Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
First Quarter 2017	130,320	1,448	$ 41.56
Second Quarter 2017	131,768	1,448	$ 41.56
Third Quarter 2017	133,216	1,448	$ 41.56
Fourth Quarter 2017	133,216	1,448	$ 41.56
Total	528,520		
Average price			$ 41.56

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Crude Oil Basis Swap Contracts

The Company has entered into crude oil basis swaps to mitigate the risk of future changes in pricing differentials between WCS and NYMEX WTI. At June 30, 2017, the Company had the following derivatives related to crude oil basis swaps in its fuel products segment, none of which are designated as hedges:

Crude Oil Basis Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Differential to NYMEX WTI ($/Bbl)
Third Quarter 2017	644,000	7,000	$ (13.22)
Fourth Quarter 2017	644,000	7,000	$ (13.22)
Total	1,288,000		
Average differential			$ (13.22)

At December 31, 2016, the Company had the following derivatives related to crude oil basis swaps in its fuel products segment, none of which are designated as hedges:

Crude Oil Basis Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Differential to NYMEX WTI ($/Bbl)
First Quarter 2017	630,000	7,000	$ (13.22)
Second Quarter 2017	637,000	7,000	$ (13.22)
Third Quarter 2017	644,000	7,000	$ (13.22)
Fourth Quarter 2017	644,000	7,000	$ (13.22)
Total	2,555,000		
Average differential			$ (13.22)

Crude Oil Percentage Basis Swap Contracts

The Company has entered into derivative instruments to secure a percentage differential of WCS crude oil to NYMEX WTI. At June 30, 2017, the Company had the following derivatives related to crude oil percentage basis swaps in its fuel products segment, none of which are designated as hedges:

Crude Oil Percentage Basis Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Fixed Percentage of NYMEX WTI (Average % of WTI/Bbl)
Third Quarter 2017	276,000	3,000	72.3 %
Fourth Quarter 2017	276,000	3,000	72.3 %
Total	552,000		
Average percentage			72.3 %

At December 31, 2016, the Company had the following derivatives related to crude oil percentage basis swaps in its fuel products segment, none of which are designated as hedges:

Crude Oil Percentage Basis Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Fixed Percentage of NYMEX WTI

			(Average % of WTI/Bbl)	
First Quarter 2017	270,000	3,000	72.3	%
Second Quarter 2017	273,000	3,000	72.3	%
Third Quarter 2017	276,000	3,000	72.3	%
Fourth Quarter 2017	276,000	3,000	72.3	%
Total	1,095,000			
Average percentage			72.3	%

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Gasoline Crack Spread Swap Contracts

At June 30, 2017, the Company did not have any derivatives related to gasoline crack spread sales in its fuel products segment.

At December 31, 2016, the Company had the following derivatives related to gasoline crack spread sales in its fuel products segment, none of which are designated as hedges:

Gasoline Crack Spread Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
First Quarter 2017	590,000	6,556	$ 10.21
Total	590,000		
Average price			$ 10.21

Diesel Crack Spread Swap Contracts

At June 30, 2017, the Company did not have any derivatives related to diesel crack spread sales in its fuel products segment.

At December 31, 2016, the Company had the following derivatives related to diesel crack spread sales in its fuel products segment, none of which are designated as hedges:

Diesel Crack Spread Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
First Quarter 2017	590,000	6,556	$ 13.67
Total	590,000		
Average price			$ 13.67

2/1/1 Crack Spread Swap Contracts

At June 30, 2017, the Company did not have any derivatives related to 2/1/1 crack spread sales in its fuel products segment.

At December 31, 2016, the Company had the following derivatives related to 2/1/1 crack spread sales in its fuel products segment, none of which are designated as hedges:

2/1/1 Crack Spread Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
First Quarter 2017	590,000	6,556	$ 11.91
Total	590,000		
Average price			$ 11.91

9. Fair Value Measurements

The Company uses a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value. Observable inputs are from sources independent of the Company. Unobservable inputs reflect the Company's assumptions about the factors market participants would use in valuing the asset or liability developed based upon the best information available in the circumstances. These tiers include the following:

- Level 1 — inputs include observable unadjusted quoted prices in active markets for identical assets or liabilities
- Level 2 — inputs include other than quoted prices in active markets that are either directly or indirectly observable
- Level 3 — inputs include unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions

In determining fair value, the Company uses various valuation techniques and prioritizes the use of observable inputs. The availability of observable inputs varies from instrument to instrument and depends on a variety of factors including the type of instrument, whether the instrument is actively traded and other characteristics particular to the instrument. For many financial instruments, pricing inputs are readily observable in the market, the valuation methodology used is widely accepted by market participants and the valuation does not require significant management judgment. For other financial instruments, pricing inputs are less observable in the marketplace and may require management judgment.

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Recurring Fair Value Measurements

Derivative Assets and Liabilities

Derivative instruments are reported in the accompanying unaudited condensed consolidated financial statements at fair value. The Company’s commodity derivative instruments consist of over-the-counter (“OTC”) contracts, which are not traded on a public exchange. Substantially all of the Company’s commodity derivative instruments are with counterparties that have long-term credit ratings of at least Baa2 and BBB+ by Moody’s and S&P, respectively.

To estimate the fair values of the Company’s commodity derivative instruments, the Company uses the forward rate, the strike price, contractual notional amounts, the risk free rate of return and contract maturity. To estimate the fair value of the Company’s fixed-to-floating interest rate swap derivative instrument prior to settlement, the Company used discounted cash flows, which use observable inputs such as maturity and market interest rates. Various analytical tests are performed to validate the counterparty data. The fair values of the Company’s derivative instruments are adjusted for nonperformance risk and creditworthiness of the hedging entities through the Company’s credit valuation adjustment (“CVA”). The CVA is calculated at the counterparty level utilizing the fair value exposure at each payment date and applying a weighted probability of the appropriate survival and marginal default percentages. The Company uses the counterparty’s marginal default rate and the Company’s survival rate when the Company is in a net asset position at the payment date and uses the Company’s marginal default rate and the counterparty’s survival rate when the Company is in a net liability position at the payment date. As a result of applying the applicable CVA at June 30, 2017, the Company’s net assets were increased by approximately $0.2 million and net liabilities were reduced by approximately $0.2 million. As a result of applying the CVA at December 31, 2016, the Company’s net assets were increased by less than $0.1 million and net liabilities were reduced by approximately $0.5 million.

Observable inputs utilized to estimate the fair values of the Company’s derivative instruments were based primarily on inputs that are readily available in public markets or can be derived from information available in publicly quoted markets. Based on the use of various unobservable inputs, principally nonperformance risk, creditworthiness of the hedging entities and unobservable inputs in the forward rate, the Company has categorized these derivative instruments as Level 3. Significant increases (decreases) in any of those unobservable inputs in isolation would result in a significantly lower (higher) fair value measurement. The Company believes it has obtained the most accurate information available for the types of derivative instruments it holds. See Note 8 for further information on derivative instruments.

Pension Assets

Pension assets are reported at fair value in the accompanying unaudited condensed consolidated financial statements. At June 30, 2017, the Company’s investments associated with its pension plan (as such term is hereinafter defined) primarily consisted of mutual funds. The mutual funds are valued at the net asset value (“NAV”) of shares in each fund held by the pension plan at quarter end as provided by the respective investment sponsors or investment advisers. Plan investments can be redeemed within a short time frame (approximately 10 business days), if requested. See Note 10 for further information on pension assets.

Liability Awards

Unit based compensation liability awards are awards that are expected to be settled in cash on their vesting dates, rather than in equity units (“Liability Awards”). The Liability Awards are categorized as Level 1 because the fair value of the Liability Awards is based on the Company’s quoted closing unit price as of each balance sheet date.

Renewable Identification Numbers Obligation

The RINs Obligation is categorized as Level 2 and is measured at fair value using the market approach based on quoted prices from an independent pricing service. See Note 5 for further information on the Company’s RINs Obligation.

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Hierarchy of Recurring Fair Value Measurements

The Company's recurring assets and liabilities measured at fair value at June 30, 2017, and December 31, 2016, were as follows (in millions):

	June 30, 2017				December 31, 2016			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Derivative assets:								
Natural gas swaps	$—	$—	$(0.8)	$(0.8)	$—	$—	$—	$—
Crude oil swaps	—	—	(0.9)	(0.9)	—	—	2.9	2.9
Crude oil percentage basis swaps	—	—	0.4	0.4	—	—	—	—
Crude oil basis swaps	—	—	2.3	2.3	—	—	(2.1)	(2.1)
Total derivative assets	—	—	1.0	1.0	—	—	0.8	0.8
Pension plan investments	0.1	—	—	0.1	0.3	—	—	0.3
Total recurring assets at fair value	$0.1	$—	$1.0	$1.1	$0.3	$—	$0.8	$1.1
Liabilities:								
Derivative liabilities:								
Inventory financing obligation	$—	$—	$(0.9)	$(0.9)	$—	$—	$—	$—
Crude oil swaps	—	—	(1.7)	(1.7)	—	—	(0.8)	(0.8)
Crude oil basis swaps	—	—	—	—	—	—	(5.0)	$(5.0)
Crude oil percentage basis swaps	—	—	0.4	0.4	—	—	(0.5)	(0.5)
Gasoline crack spread swaps	—	—	—	—	—	—	(3.5)	(3.5)
Diesel crack spread swaps	—	—	—	—	—	—	(1.4)	(1.4)
2/1/1 crack spread swaps	—	—	—	—	—	—	(2.5)	(2.5)
Natural gas swaps	—	—	(0.8)	(0.8)	—	—	(1.1)	(1.1)
Total derivative liabilities	—	—	(3.0)	(3.0)	—	—	(14.8)	(14.8)
RINs Obligation	—	(25.6)	—	(25.6)	—	(79.3)	—	(79.3)
Liability Awards	(0.4)	—	—	(0.4)	—	—	—	—
Total recurring liabilities at fair value	$(0.4)	$(25.6)	$(3.0)	$(29.0)	$—	$(79.3)	$(14.8)	$(94.1)

The table below sets forth a summary of net changes in fair value of the Company's Level 3 financial assets and liabilities for the six months ended June 30, 2017 and 2016 (in millions):

	Six Months Ended June 30,	
	2017	2016
Fair value at January 1,	$(14.0)	$(33.9)
Realized loss on derivative instruments	4.9	18.3
Unrealized gain on derivative instruments	11.9	28.4
Settlements	(4.8)	(18.3)
Fair value at June 30,	$(2.0)	$(5.5)
Total gain included in net income (loss) attributable to changes in unrealized gain relating to financial assets and liabilities held as of June 30,	$11.9	$28.4

All settlements from derivative instruments designated as cash flow hedges and deemed "effective" are included in sales for gasoline, diesel and jet fuel derivatives, and cost of sales for crude oil derivatives in the unaudited condensed consolidated statements of operations in the period that the hedged cash flow occurs. Any "ineffectiveness" associated with these settlements from derivative instruments designated as cash flow hedges are recorded in earnings in gain (loss) on derivative instruments in

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the unaudited condensed consolidated statements of operations. All settlements from derivative instruments designated as fair value hedges are accrued and recorded as an adjustment to interest expense in the unaudited condensed consolidated statements of operations. All settlements from derivative instruments not designated as hedges are recorded in gain (loss) on derivative instruments in the unaudited condensed consolidated statements of operations. See Note 8 for further information on derivative instruments.

Nonrecurring Fair Value Measurements

Certain nonfinancial assets and liabilities are measured at fair value on a nonrecurring basis and are subject to fair value adjustments in certain circumstances, such as when there is evidence of impairment. Assets and liabilities acquired in business combinations are recorded at their fair value as of the date of acquisition.

The Company reviews for goodwill impairment annually on October 1 and whenever events or changes in circumstances indicate its carrying value may not be recoverable. The fair value of the reporting units is determined using the income approach. The income approach focuses on the income-producing capability of an asset, measuring the current value of the asset by calculating the present value of its future economic benefits such as cash earnings, cost savings, corporate tax structure and product offerings. Value indications are developed by discounting expected cash flows to their present value at a rate of return that incorporates the risk-free rate for the use of funds, the expected rate of inflation and risks associated with the reporting unit. These assets would generally be classified within Level 3, in the event that the Company were required to measure and record such assets at fair value within its unaudited condensed consolidated financial statements.

The Company periodically evaluates the carrying value of long-lived assets to be held and used, including indefinite-lived intangible assets and property, plant and equipment, when events or circumstances warrant such a review. Fair value is determined primarily using anticipated cash flows assumed by a market participant discounted at a rate commensurate with the risk involved and these assets would generally be classified within Level 3, in the event that the Company was required to measure and record such assets at fair value within its unaudited condensed consolidated financial statements.

Estimated Fair Value of Financial Instruments

Cash and Cash Equivalents

The carrying value of cash and cash equivalents is considered to be representative of its fair value.

Debt

The estimated fair value of long-term debt at June 30, 2017, and December 31, 2016, consists primarily of senior notes. The estimated aggregate fair value of the Company’s senior notes defined as Level 1 was based upon quoted market prices in an active market. The estimated aggregate fair value of the Company’s senior secured notes classified as Level 2 was based upon directly observable inputs. The carrying value of borrowings, if any, under the Company’s revolving credit facility, capital lease obligations and other obligations approximate their fair values as determined by discounted cash flows and are classified as Level 3. See Note 7 for further information on long-term debt.

The Company’s carrying and estimated fair value of the Company’s financial instruments, carried at adjusted historical cost, at June 30, 2017, and December 31, 2016, were as follows (in millions):

		June 30, 2017		December 31, 2016	
	Level	Fair Value	Carrying Value	Fair Value	Carrying Value
Financial Instrument:					
Senior notes	1	$1,379.3	$ 1,554.3	$1,334.1	$ 1,552.2
Senior secured notes	2	$463.2	$ 386.0	$458.8	$ 384.5
Revolving credit facility	3	$0.4	$ 0.4	$6.0	$ 6.0
Capital lease and other obligations	3	$52.5	$ 52.5	$54.5	$ 54.5

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10. Employee Benefit Plans

The components of net periodic benefit income for the three and six months ended June 30, 2017 and 2016, were as follows (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Interest cost	$0.6	$0.7	$1.2	$1.3
Expected return on assets	(0.8)	(0.8)	(1.6)	(1.6)
Amortization of net loss	—	0.1	—	0.1
Net periodic benefit income	$(0.2)	$—	$(0.4)	$(0.2)

At June 30, 2017, and December 31, 2016, the Company's investments associated with its pension plan primarily consisted of (i) cash and cash equivalents and (ii) mutual funds. Mutual funds are valued based on the NAV per share (or its equivalent) as a practical expedient to estimate fair value due to the absence of readily available market prices. NAV's are provided by the respective investment sponsors or investment advisers and are subsequently reviewed and necessary to make an adjustment at the balance sheet date. In determining whether an adjustment to the external valuation is required, the Company will review material factors that could affect the valuation, such as changes to the composition of performance of the underlying investments or comparable investments, overall market conditions, expected sale prices for private investments which are probable of being sold in the short-term and other economic factors that may possibly have a favorable or unfavorable effect on the reported external valuation. See Note 9 for the definition of Level 1.

The Company's pension plan assets measured at fair value at June 30, 2017, and December 31, 2016, were as follows (in millions):

	June 30, 2017		December 31, 2016	
	Level 1	Total	Level 1	Total
Plan assets subject to leveling:				
Cash and cash equivalents	$0.1	$0.1	$0.3	$0.3
Total plan assets subject to leveling	$0.1	0.1	$0.3	0.3
Plan assets measured at net asset value:				
Domestic equities		9.3		8.6
Foreign equities		9.3		8.7
Fixed income		34.0		32.2
Total plan assets measured at net asset value		52.6		49.5
Total plan assets		$52.7		$49.8

Investment Fund Strategies

Domestic equity funds include funds that invest in U.S. common and preferred stocks. Foreign equity funds invest in securities issued by companies listed on international stock exchanges. Certain funds have value and growth objectives and managers may attempt to profit from security mispricing in equity markets to meet these objectives. Short-term investments (including commercial paper, certificates of deposits and government repurchase agreements) and derivatives may be used for hedging purposes to limit exposure to various risk factors.

Fixed income funds invest in U.S. dollar-denominated, investment grade bonds, including U.S. Treasury and government agency securities, corporate bonds and mortgage and asset-backed securities. These funds may also invest in any combination of non-investment grade bonds, non-U.S. dollar-denominated bonds and bonds issued by issuers in emerging capital markets. Short-term investments (including commercial paper, certificates of deposits and government repurchase agreements) and derivatives may be used for hedging purposes to limit exposure to various risk factors.

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11. Accumulated Other Comprehensive Loss

The table below sets forth a summary of reclassification adjustments out of accumulated other comprehensive loss in the Company’s unaudited condensed consolidated statements of operations for the three and six months ended June 30, 2017 and 2016 (in millions):

Components of Accumulated Other Comprehensive Loss	Amount Reclassified From Accumulated Other Comprehensive Loss				Location of Gain (Loss)
	Three Months Ended June 30,		Six Months Ended June 30,		
	2017	2016	2017	2016	
Derivative gains (losses) reflected in gross profit:					
	$ —	$ 15.1	$ —	$ 31.1	Sales
	—	(12.8)	—	(26.7)	Cost of sales
	$ —	$ 2.3	$ —	$ 4.4	Total
Amortization of defined benefit pension plans:					
Amortization of net loss	$ —	$ (0.1)	$ —	$ (0.1)	[1]
	$ —	$ (0.1)	$ —	$ (0.1)	Total

[1] This accumulated other comprehensive loss component is included in the computation of net periodic benefit income. See Note 10 for additional details.

12. Earnings Per Unit

The following table sets forth the computation of basic and diluted earnings per limited partner unit for the three and six months ended June 30, 2017 and 2016 (in millions, except unit and per unit data):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Numerator for basic and diluted earnings per limited partner unit:				
Net income (loss)	$9.6	$ (147.9)	$3.4	$ (215.6)
General partner’s interest in net income (loss)	0.2	(2.9)	0.1	(4.3)
Non-vested share based payments	0.2	—	0.2	—
Net income (loss) available to limited partners	$9.2	$ (145.0)	$3.1	$ (211.3)
Denominator for basic and diluted earnings per limited partner unit:				
Basic weighted average limited partner units outstanding	77,554,815	76,761,504	77,485,068	76,491,775
Effect of dilutive securities:				
Participating securities — phantom units	159,297	—	240,598	—
Diluted weighted average limited partner units outstanding [1]	77,714,112	76,761,504	77,725,666	76,491,775
Limited partners’ interest basic and diluted net income (loss) per unit	$0.12	$ (1.89)	$0.04	$ (2.76)

[1] Total diluted weighted average limited partner units outstanding excludes 0.1 million and 0.2 million, respectively, of dilutive phantom units for the three and six months ended June 30, 2016.

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13. Segments and Related Information

a. Segment Reporting

The Company manages its business in multiple operating segments, which are grouped on the basis of similar product, market and operating factors into the following reportable segments:

- Specialty Products. The specialty products segment produces a variety of lubricating oils, solvents, waxes, synthetic lubricants and other products which are sold to customers who purchase these products primarily as raw material components for basic automotive, industrial and consumer goods. Specialty products also include synthetic lubricants used primarily in manufacturing, mining and automotive applications.
- Fuel Products. The fuel products segment produces primarily gasoline, diesel, jet fuel and asphalt which are primarily sold to customers located in the PADD 2, PADD 3 and PADD 4 areas within the U.S.
- Oilfield Services. The oilfield services segment markets its products and oilfield services including drilling fluids, completion fluids and solids control services to the oil and gas industry.

The accounting policies of the reporting segments are the same as those described in the summary of significant accounting policies as disclosed in Note 2 — "Summary of Significant Accounting Policies" in Part II, Item 8 "Financial Statements and Supplementary Data" of the Company's 2016 Annual Report, except that the disaggregated financial results for the reporting segments have been prepared using a management approach, which is consistent with the basis and manner in which management internally disaggregates financial information for the purposes of assisting internal operating decisions. The Company accounts for intersegment sales and transfers at cost plus a specified mark-up. The Company evaluates performance based upon Adjusted EBITDA (a non-GAAP financial measure). The Company defines Adjusted EBITDA for any period as: (1) net income (loss) plus (2)(a) interest expense; (b) income taxes; (c) depreciation and amortization; (d) impairment; (e) unrealized losses from mark to market accounting for hedging activities; (f) realized gains under derivative instruments excluded from the determination of net income (loss); (g) non-cash equity-based compensation expense and other non-cash items (excluding items such as accruals of cash expenses in a future period or amortization of a prepaid cash expense) that were deducted in computing net income (loss); (h) debt refinancing fees, premiums and penalties; (i) any net loss realized in connection with an asset sale that was deducted in computing net income (loss) and (j) all extraordinary, unusual or non-recurring items of gain or loss, or revenue or expense; minus (3)(a) unrealized gains from mark to market accounting for hedging activities; (b) realized losses under derivative instruments excluded from the determination of net income (loss) and (c) other non-recurring expenses and unrealized items that reduced net income (loss) for a prior period, but represent a cash item in the current period.

The Company manages its assets on a total company basis, not by segment. Therefore, management does not review any asset information by segment and, accordingly, the Company does not report asset information by segment.

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Reportable segment information for the three months ended June 30, 2017 and 2016, is as follows (in millions):

Three Months Ended June 30, 2017	Specialty Products	Fuel Products	Oilfield Services	Combined Segments	Eliminations	Consolidated Total
Sales:						
External customers	$ 343.1	$ 623.9	$ 63.9	$ 1,030.9	$ —	$ 1,030.9
Intersegment sales	0.1	17.4	—	17.5	(17.5)	—
Total sales	$ 343.2	$ 641.3	$ 63.9	$ 1,048.4	$ (17.5)	$ 1,030.9
Loss from unconsolidated affiliates	$ —	$ —	$ (0.1)	$ (0.1)	$ —	$ (0.1)
Adjusted EBITDA	$ 67.1	$ 34.0	$ 0.5	$ 101.6	$ —	$ 101.6
Reconciling items to net income:						
Depreciation and amortization	15.9	27.8	3.8	47.5	—	47.5
Unrealized gain on derivatives						(1.3)
Interest expense						44.5
Non-cash equity based compensation and other non-cash items						2.2
Income tax benefit						(0.9)
Net income						$ 9.6

Three Months Ended June 30, 2016	Specialty Products	Fuel Products	Oilfield Services	Combined Segments	Eliminations	Consolidated Total
Sales:						
External customers	$ 332.4	$ 619.2	$ 21.3	$ 972.9	$ —	$ 972.9
Intersegment sales	—	10.0	—	10.0	(10.0)	—
Total sales	$ 332.4	$ 629.2	$ 21.3	$ 982.9	$ (10.0)	$ 972.9
Loss from unconsolidated affiliates	$ —	$ (7.0)	$ (0.1)	$ (7.1)	$ —	$ (7.1)
Adjusted EBITDA	$ 59.0	$ 18.9	$ (7.9)	$ 70.0	$ —	$ 70.0
Reconciling items to net loss:						
Depreciation and amortization	18.8	28.5	4.8	52.1	—	52.1
Realized gain (loss) on derivatives, not reflected in net loss or settled in a prior period	0.5	(2.8)	—	(2.3)	—	(2.3)
Impairment charges	—	33.4	—	33.4	—	33.4
Loss on sale of unconsolidated affiliate	—	113.9	—	113.9	—	113.9
Unrealized gain on derivatives						(23.8)
Interest expense						42.8
Non-cash equity based compensation and other non-cash items						1.5
Income tax expense						0.3
Net loss						$ (147.9)

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Reportable segment information for the six months ended June 30, 2017 and 2016, is as follows (in millions):

Six Months Ended June 30, 2017	Specialty Products	Fuel Products	Oilfield Services	Combined Segments	Eliminations	Consolidated Total
Sales:						
External customers	$ 680.3	$ 1,173.2	$ 114.8	$ 1,968.3	$ —	$ 1,968.3
Intersegment sales	0.2	32.6	—	32.8	(32.8)	—
Total sales	$ 680.5	$ 1,205.8	$ 114.8	$ 2,001.1	$ (32.8)	$ 1,968.3
Loss from unconsolidated affiliates	$ —	$ —	$ (0.2)	$ (0.2)	$ —	$ (0.2)
Adjusted EBITDA	$ 112.7	$ 70.8	$ (3.2)	$ 180.3	$ —	$ 180.3
Reconciling items to net income:						
Depreciation and amortization	32.9	55.3	7.8	96.0	—	96.0
Impairment charges	0.4	—	—	0.4	—	0.4
Unrealized gain on derivatives						(11.9)
Interest expense						88.4
Non-cash equity based compensation and other non-cash items						5.0
Income tax benefit						(1.0)
Net income						$ 3.4

Six Months Ended June 30, 2016	Specialty Products	Fuel Products	Oilfield Services	Combined Segments	Eliminations	Consolidated Total
Sales:						
External customers	$ 633.1	$ 999.1	$ 53.7	$ 1,685.9	$ —	$ 1,685.9
Intersegment sales	0.4	13.7	—	14.1	(14.1)	—
Total sales	$ 633.5	$ 1,012.8	$ 53.7	$ 1,700.0	$ (14.1)	$ 1,685.9
Loss from unconsolidated affiliates	$ —	$ (18.0)	$ (0.2)	$ (18.2)	$ —	$ (18.2)
Adjusted EBITDA	$ 117.5	$ (27.1)	$ (13.8)	$ 76.6	$ —	$ 76.6
Reconciling items to net loss:						
Depreciation and amortization	37.2	53.2	9.6	100.0	—	100.0
Realized gain (loss) on derivatives, not reflected in net loss or settled in a prior period	1.2	(5.6)	—	(4.4)	—	(4.4)
Impairment charges	—	33.4	—	33.4	—	33.4
Loss on sale of unconsolidated affiliate	—	113.9	—	113.9	—	113.9
Unrealized gain on derivatives						(28.4)
Interest expense						73.1
Non-cash equity based compensation and other non-cash items						4.1
Income tax expense						0.5
Net loss						$ (215.6)

b. Geographic Information

International sales accounted for less than 10% of consolidated sales in each of the three and six months ended June 30, 2017 and 2016. Substantially all of the Company’s long-lived assets are domestically located.

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c. Product Information

The Company offers specialty products primarily in categories consisting of lubricating oils, solvents, waxes, packaged and synthetic specialty products and other. Fuel products categories primarily consist of gasoline, diesel, jet fuel, asphalt, heavy fuel oils and other. All oilfield services products are consolidated in a standalone category. The following table sets forth the major product category sales for the three months ended June 30, 2017 and 2016 (dollars in millions):

	Three Months Ended June 30,					
	2017			2016		
Specialty products:						
Lubricating oils	$153.1	14.9	%	$146.3	15.0	%
Solvents	68.6	6.7	%	61.1	6.3	%
Waxes	29.0	2.8	%	36.3	3.7	%
Packaged and synthetic specialty products	83.1	8.1	%	76.6	7.9	%
Other	9.3	0.8	%	12.1	1.3	%
Total	$343.1	33.3	%	$332.4	34.2	%
Fuel products:						
Gasoline	$247.4	24.0	%	$228.0	23.4	%
Diesel	210.2	20.4	%	238.6	24.5	%
Jet fuel	32.8	3.2	%	25.8	2.7	%
Asphalt, heavy fuel oils and other	133.5	12.9	%	126.8	13.0	%
Total	$623.9	60.5	%	$619.2	63.6	%
Oilfield services:						
Total	$63.9	6.2	%	$21.3	2.2	%
Consolidated sales	$1,030.9	100.0	%	$972.9	100.0	%

The following table sets forth the major product category sales for the six months ended June 30, 2017 and 2016 (dollars in millions):

	Six Months Ended June 30,					
	2017			2016		
Specialty products:						
Lubricating oils	$304.4	15.5	%	$275.5	16.3	%
Solvents	136.1	6.9	%	117.0	6.9	%
Waxes	60.0	3.0	%	63.5	3.8	%
Packaged and synthetic specialty products	161.5	8.2	%	157.5	9.3	%
Other	18.3	0.9	%	19.6	1.3	%
Total	$680.3	34.5	%	$633.1	37.6	%
Fuel products:						
Gasoline	$475.6	24.2	%	$390.2	23.1	%
Diesel	417.0	21.2	%	377.5	22.4	%
Jet fuel	70.4	3.6	%	49.2	2.9	%
Asphalt, heavy fuel oils and other	210.2	10.7	%	182.2	10.8	%
Total	$1,173.2	59.7	%	$999.1	59.2	%
Oilfield services:						
Total	$114.8	5.8	%	$53.7	3.2	%
Consolidated sales	$1,968.3	100.0	%	$1,685.9	100.0	%

d. Major Customers

During the three and six months ended June 30, 2017 and 2016, the Company had no customer that represented 10% or greater of consolidated sales.

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e. Major Suppliers

During the three months ended June 30, 2017 and 2016, the Company had two suppliers that supplied approximately 66.9% and 60.7%, respectively, of its crude oil supply. During the six months ended June 30, 2017 and 2016, the Company had two suppliers that supplied approximately 66.5% and 57.0%, respectively, of its crude oil supply.

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

The historical unaudited condensed consolidated financial statements included in this Quarterly Report reflect all of the assets, liabilities and results of operations of Calumet Specialty Products Partners, L.P. ("Calumet," the "Company," "we," "our," or "us"). The following discussion analyzes the financial condition and results of operations of the Company for the three and six months ended June 30, 2017 and 2016. Investors should read the following discussion and analysis of the financial condition and results of operations of the Company in conjunction with our 2016 Annual Report and the historical unaudited condensed consolidated financial statements and notes of the Company included elsewhere in this Quarterly Report.

Overview

We are a leading independent producer of high-quality, specialty hydrocarbon products in North America. We are headquartered in Indianapolis, Indiana, and own specialty and fuel products facilities primarily located in northwest Louisiana, northwest Wisconsin, northern Montana, western Pennsylvania, Texas, New Jersey, and eastern Missouri. We own and lease oilfield services locations in Texas, Oklahoma, Louisiana, Arkansas, Colorado, Utah, Wyoming, Montana, New Mexico, New York, North Dakota, Pennsylvania and Ohio. We own and lease additional facilities, primarily related to production and distribution of specialty, fuel and oilfield services products, throughout the United States ("U.S."). Our business is organized into three segments: specialty products, fuel products and oilfield services. In our specialty products segment, we process crude oil and other feedstocks into a wide variety of customized lubricating oils, white mineral oils, solvents, petrolatums and waxes. Our specialty products are sold to domestic and international customers who purchase them primarily as raw material components for basic industrial, consumer and automotive goods. We also blend and market specialty products through our Royal Purple, Bel-Ray, TruFuel and Quantum brands. In our fuel products segment, we process crude oil into a variety of fuel and fuel-related products, including gasoline, diesel, jet fuel, asphalt and heavy fuel oils, and from time to time resell purchased crude oil to third-party customers. Our oilfield services segment manufactures and markets products and provides oilfield services including drilling fluids, completion fluids and solids control services to the oil and gas exploration industry throughout the U.S.

Second Quarter 2017 Update

Outlook and Trends

Commodity markets and corresponding fluctuations in product margins have been mixed during the six months ended June 30, 2017, with the average price per barrel of New York Mercantile Exchange West Texas Intermediate ("NYMEX WTI") crude oil decreasing approximately 7% in the second quarter of 2017 as compared to the first quarter of 2017. We expect volatility to continue for the remainder of 2017. Below are factors that have impacted or may impact our results of operations during 2017:

- Gasoline margins have been volatile, but are expected to increase in response to the higher domestic demand associated with the summer driving season. Diesel margins have been negatively impacted by oversupply and decreases in drilling activities; however, margins are also expected to increase as we move into the summer driving season.
- Environmental regulations continue to affect our margins in the form of the cost of Renewable Identification Numbers ("RINs"). To the extent we are unable to blend biofuels, we must purchase RINs in the open market to satisfy our annual requirement. The 34% increase in the price of RINs during the second quarter 2017 unfavorably affected our results of operations. It is not possible to predict what future RINs volumes or costs may be given the volatile price of RINs, but we continue to anticipate that RINs have the potential to remain a significant expense for our fuel products segment (inclusive of the favorable impact of exemptions received), assuming current market prices for RINs continue.
- Asphalt demand is expected to increase due to the seasonality of the road construction and roofing industries, which have shown increased demand in prior years.

- Although heavy sour crude oil discounts have narrowed recently, they are expected to remain wide over the long term as sour crude oil remains oversupplied. Sweet crude oil discounts are expected to remain weak on lower domestic sweet crude oil production and higher foreign sweet and sour crude oil imports. Processing heavy sour crude oil in our refining system results in a lower overall delivered cost of crude oil.
- Specialty products margins have remained relatively stable and are expected to remain stable in the near term. We continue to consider our specialty products segment our core business, over the long term, and we plan to seek appropriate ways to invest in our specialty products segment while divesting in non-core businesses. Likewise, we are currently evaluating opportunities to divest non-core businesses and assets in line with our strategy of preserving liquidity and streamlining our business to better focus on the advancement of our core business. However, there can be no assurance as to the timing

or success of any such potential transactions, or that we will be able to sell these assets or non-core businesses on satisfactory terms, if at all. In addition, our acquisition program targets assets that management believes will be financially accretive, and we intend to focus on targeted strategic acquisitions of specialty products assets that leverage an existing core competency and that have an identifiable competitive advantage we can exploit as the new owner.

- Our oilfield services segment was positively impacted by a 43% increase in the land-based rig count during the six months ended June 30, 2017. We anticipate that the remainder of 2017 will remain challenging, and we plan to continue to align our cost structure with market conditions including rig count, which we believe will position us favorably when the drilling market ultimately recovers.

Financial Results

We reported net income of $9.6 million in the second quarter 2017, versus a net loss of $147.9 million in the second quarter 2016. We reported Adjusted EBITDA (as defined in "Non-GAAP Financial Measures") of $101.6 million in the second quarter 2017, versus $70.0 million in the second quarter 2016. We used cash from operations of $35.6 million in the six months ended June 30, 2017, versus cash used of $51.7 million in the six months ended June 30, 2016. Please read "— Non-GAAP Financial Measures" for a reconciliation of EBITDA, Adjusted EBITDA and Distributable Cash Flow to net income (loss), our most directly comparable financial performance measure and for a reconciliation of Distributable Cash Flow to net cash used in operating activities, our most directly comparable financial liquidity measure, both calculated and presented in accordance with GAAP.

Commodity markets remained volatile in the second quarter 2017, contributing to fluctuations in refined product margins. The average price of NYMEX WTI crude oil increased approximately 5% in the second quarter 2017, when compared to the prior year period. In the second quarter 2017, the average price differential per barrel between Western Canadian Select ("WCS") crude oil and NYMEX WTI averaged $9 per barrel below NYMEX WTI, versus $12 per barrel below NYMEX WTI in the second quarter 2016. Given our access to cost advantaged, heavy Canadian crude oil in our northern refining system, we have embarked on a multi-year plan to increase our ability to process this crude oil grade over time. In the second quarter 2017, we processed 41,600 bpd of heavy Canadian crude oil, versus 35,000 bpd in the second quarter 2016.

Specialty products segment Adjusted EBITDA was $67.1 million in the second quarter 2017, versus $59.0 million in the second quarter 2016, due primarily to widening margins partially offset by a decrease in the favorable lower of cost or market ("LCM") inventory adjustment and decreased sales volume. Second quarter 2017 results were impacted by a $0.4 million LCM inventory adjustment.

Fuel products segment Adjusted EBITDA was $34.0 million during the second quarter 2017, versus $18.9 million in the second quarter 2016, due primarily to a year-over-year increase in benchmark refined products margins and decreased RINs compliance costs, partially offset by a decrease in the favorable LCM inventory adjustment and decreased sales volume. Second quarter 2017 results were impacted by a $4.2 million favorable LCM inventory adjustment.

For benchmarking purposes, we compare our per barrel refined fuel products margin to the U.S. Gulf Coast 2/1/1 crack spread ("Gulf Coast crack spread"). The Gulf Coast crack spread represents the approximate gross margin per barrel that results from processing two barrels of crude oil into one barrel of gasoline and one barrel of ultra-low sulfur diesel fuel. The Gulf Coast crack spread is calculated using the near-month futures price of NYMEX WTI crude oil, the price of U.S. Gulf Coast Pipeline 87 Octane Conventional Gasoline and the price of U.S. Gulf Coast Pipeline Ultra-Low Sulfur Diesel ("ULSD"). During the second quarter 2017, the Gulf Coast crack spread averaged approximately $15 per barrel compared to approximately $13 per barrel in the prior year period, an approximate 17% increase. The Gulf Coast ULSD crack spread averaged approximately $14 per barrel during the second quarter 2017, compared to approximately $11 per barrel in the prior year period. The Gulf Coast gasoline crack spread averaged approximately $16 per barrel during the second quarter 2017, compared to approximately $14 per barrel in the prior year period. Total fuel products segment sales volumes decreased 7.9% in the second quarter 2017, when compared to the second quarter 2016 primarily as a result of turnaround activities at the Superior refinery.

The annual asphalt selling season historically begins in April and ends in October, subject to slight timing variations attributable to weather conditions that dictate the ability of customers to engage in roofing and road paving activities. Historically, we have sold higher volumes of asphalt produced in our system into the wholesale channel; however, beginning in 2016, we have increasingly focused efforts to expand into higher margin retail-oriented channels. Generally speaking, a declining crude oil price environment may allow for temporarily higher margins on our asphalt products, as product prices lag declines in feedstock costs, while rising crude oil prices may cause margins to temporarily contract, subject to market adjustments in product prices.

Our oilfield services segment was positively impacted by a 43% increase in the land-based rig count during the six months ended June 30, 2017 compared to the end of 2016. Increases in crude oil and natural gas prices impacted our customers' drilling and production activities during 2017, which resulted in a favorable impact on our sales and gross profit in 2017. Additionally, our oilfield services segment had a $0.2 million favorable LCM inventory adjustment in the second quarter 2017. We anticipate that the remainder of 2017 will remain challenging, and we plan to continue to align our cost structure with market conditions including rig count, which we believe will position us favorably when the drilling market ultimately recovers.

Liquidity Update

As of June 30, 2017, we had availability under our revolving credit facility of $342.1 million, based on a $439.6 million borrowing base, $97.1 million in outstanding standby letters of credit and $0.4 million in outstanding borrowings. In addition, we had $26.6 million of cash on hand as of June 30, 2017. We believe we will continue to have sufficient liquidity from cash on hand, projected cash flow from operations, borrowing capacity and other means by which to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures. Our revolving credit facility matures in July 2019. The inventory financing agreements used for the Great Falls refinery mature in October 2019; however Macquarie Energy North America Trading Inc. ("Macquarie") has the option to terminate the agreements with nine months notice any time prior to June 2019. The inventory financing agreements used for the Shreveport refinery mature in June 2020; however, Macquarie has the option to terminate the agreements with nine months notice any time prior to June 2019.

Renewable Fuel Standard Update

Along with the broader refining industry, we remain subject to compliance costs under the Renewable Fuel Standard ("RFS"). Under the regulation of the Environmental Protection Agency ("EPA"), the RFS provides annual requirements for the total volume of renewable fuels which are mandated to be blended into finished transportation fuels. If a refiner does not meet its required annual Renewable Volume Obligation, the refiner can purchase blending credits in the open market, referred to as RINs.

During the second quarter 2017, we recognized a RINs gain of $16.5 million, compared to an expense of $8.2 million for the second quarter 2016. For the full-year 2017, we anticipate our gross RINs obligation will increase to 128 million RINs, given recent production capacity expansions at two of our fuel products refineries. Estimated RINs obligations remain subject to fluctuations in fuels production volumes during the full-year 2017. The gross RINs obligations exclude the potential for any subsequent hardship waivers that may or may not be granted by the EPA to any of our fuel refineries.

We continue to anticipate that expenses related to RFS compliance have the potential to remain a significant expense for our fuel products segment, assuming current market prices for RINs continue.

In February 2017 and on May 4, 2017, the EPA granted certain of the Company's refineries a "small refinery exemption" under the RFS for the full-year 2016, as provided for under the federal Clean Air Act, as amended ("CAA"). In granting those exemptions, the EPA determined that for the full-year 2016, compliance with the RFS would represent a "disproportionate economic hardship" for these refineries.

Strategic Update

In August 2016, we announced a multi-year, self-help program that focuses on value creation through operations excellence and resource optimization. In connection with this program, we are exploring a number of strategic initiatives, including pursuing a series of cost reduction initiatives, margin enhancing measures, divestiture of non-core assets and low-to-no cost projects that are intended to reduce balance sheet leverage and increase free cash flow on a sustainable basis. By year-end 2018, the program is projected to generate an incremental $150 million to $200 million of annualized Adjusted EBITDA per year as compared to 2015, including $50 million to $60 million of which is expected to be realized by year-end 2017. For information on forward-looking non-GAAP Adjusted EBITDA, please read "— Non-GAAP Financial Measures."

Key Performance Measures

Our sales and net income are principally affected by the price of crude oil, demand for specialty products, fuel products and oilfield products and services, prevailing crack spreads for fuel products, the price of natural gas used as fuel in our operations and our results from derivative instrument activities.

Our primary raw materials are crude oil and other specialty feedstocks, and our primary outputs are specialty petroleum products, fuel products and oilfield services products. The prices of crude oil, specialty products, fuel products and oilfield products and services are subject to fluctuations in response to changes in supply, demand, market uncertainties and a variety of additional factors beyond our control. We monitor these risks and enter into derivative instruments designed to help mitigate the impact of commodity price fluctuations on our business. The primary purpose of our commodity risk management activities is to economically hedge our cash flow exposure to commodity price risk so that we can meet our debt service and capital expenditure requirements despite fluctuations in crude oil and fuel products prices. We enter into derivative contracts for future periods in quantities that do not exceed our projected purchases of crude oil and natural gas and sales of fuel products. Please read Part I, Item 3 "Quantitative and Qualitative Disclosures About Market Risk — Commodity Price Risk" and Note 8 — "Derivatives" under Part I, Item 1 "Financial Statements — Notes to Unaudited Condensed Consolidated Financial Statements."

Our management uses several financial and operational measurements to analyze our performance. These measurements include the following:

- sales volumes;
- production yields;
- specialty products, fuel products and oilfield services segment gross profit;
- specialty products, fuel products and oilfield services segment Adjusted EBITDA; and

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- selling, general and administrative expenses.

Sales volumes. We view the volumes of specialty products and fuel products sold as an important measure of our ability to effectively utilize our operating assets. Our ability to meet the demands of our customers is driven by the volumes of crude oil and feedstocks that we run at our facilities. Higher volumes improve profitability both through the spreading of fixed costs over greater volumes and the additional gross profit achieved on the incremental volumes.

Production yields. In order to maximize our gross profit and minimize lower margin products, we seek the optimal product mix for each barrel of crude oil we refine, or feedstocks we, or third parties, process, which we refer to as production yield.

Specialty products, fuel products and oilfield services segment gross profit. Specialty products, fuel products and oilfield services gross profit are important measures of our ability to maximize the profitability of our specialty products, fuel products and oilfield services segments. We define gross profit as sales less the cost of crude oil and other feedstocks and other production-related and service-related expenses, the most significant portion of which includes labor, plant fuel, utilities, contract services, maintenance, depreciation and processing materials. We use gross profit as an indicator of our ability to manage our business during periods of crude oil and natural gas price fluctuations, as the prices of our specialty products and fuel products generally do not change immediately with changes in the price of crude oil and natural gas. The increase or decrease in selling prices typically lags behind the rising or falling costs, respectively, of crude oil feedstocks for specialty products. Other than plant fuel, production-related expenses generally remain stable across broad ranges of specialty products and fuel products throughput volumes, but can fluctuate depending on maintenance activities performed during a specific period.

Our fuel products segment gross profit per barrel may differ from standard U.S. Gulf Coast, Group 3, PADD 4 Billings, Montana or 3/2/1 and 2/1/1 market crack spreads due to many factors, including derivative activities to hedge both our fuel products segment sales and the cost of crude oil reflected in gross profit, our fuel products mix as shown in our production table being different than the ratios used to calculate such market crack spreads, LCM inventory adjustments reflected in gross profit, RINs costs reflected in gross profit, operating costs including fixed costs, actual crude oil costs differing from market indices and our local market pricing differentials for fuel products in the Shreveport, Louisiana, San Antonio, Texas, Superior, Wisconsin and Great Falls, Montana vicinities as compared to U.S. Gulf Coast, Group 3 and PADD 4 Billings, Montana postings.

Specialty products, fuel products and oilfield services segment Adjusted EBITDA. We believe that specialty products, fuel products and oilfield services segment Adjusted EBITDA measures are useful as they exclude transactions not related to our core cash operating activities and provide metrics to analyze our ability to pay distributions to our unitholders and pay interest to our noteholders as Adjusted EBITDA is a component in the calculation of Distributable Cash Flow and allows us to meaningfully analyze the trends and performance of our core cash operations as well as make decisions regarding the allocation of resources to segments.

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Results of Operations for the Three and Six Months Ended June 30, 2017 and 2016

Production Volume. The following table sets forth information about our combined operations, excluding the results of the oilfield services segment. Facility production volume differs from sales volume due to changes in inventories and the sale of purchased fuel product blendstocks such as ethanol and biodiesel and the resale of crude oil in our fuel products segment.

	Three Months Ended June 30,			Six Months Ended June 30,		
	2017	2016	% Change	2017	2016	% Change
	(In bpd)			(In bpd)		
Total sales volume [1]	141,154	154,286	(8.5)%	135,343	139,363	(2.9)%
Total feedstock runs [2]	136,552	143,118	(4.6)%	134,370	135,751	(1.0)%
Facility production: [3]						
Specialty products:						
Lubricating oils	15,914	15,716	1.3 %	15,539	14,785	5.1 %
Solvents	8,239	7,823	5.3 %	7,794	7,587	2.7 %
Waxes	1,373	1,581	(13.2)%	1,425	1,458	(2.3)%
Packaged and synthetic specialty products [4]	2,648	2,110	25.5 %	2,684	2,117	26.8 %
Other	1,244	1,799	(30.9)%	1,567	1,354	15.7 %
Total	29,418	29,029	1.3 %	29,009	27,301	6.3 %
Fuel products:						
Gasoline	37,225	37,954	(1.9)%	37,395	37,999	(1.6)%
Diesel	34,787	40,057	(13.2)%	33,904	35,202	(3.7)%
Jet fuel	5,306	4,314	23.0 %	6,030	4,995	20.7 %
Asphalt, heavy fuels and other	33,699	32,941	2.3 %	31,569	30,590	3.2 %
Total	111,017	115,266	(3.7)%	108,898	108,786	0.1 %
Total facility production [3]	140,435	144,295	(2.7)%	137,907	136,087	1.3 %

(1) Total sales volume includes sales from the production at our facilities and certain third-party facilities pursuant to supply and/or processing agreements, sales of inventories and the resale of crude oil to third-party customers. Total sales volume includes the sale of purchased fuel product blendstocks, such as ethanol and biodiesel, as components of finished fuel products in our fuel products segment sales.

The decrease in total sales volume for the three and six months ended June 30, 2017, as compared to the same periods in 2016, is due primarily to decreased sale volumes of fuel products primarily as a result of turnaround activities at the Superior refinery. In addition, decreased sales volume of lubricating oils and waxes was partially offset by increased sales volume of branded and packaged products as a result of market conditions.

(2) Total feedstock runs represent the bpd of crude oil and other feedstocks processed at our facilities and at certain third-party facilities pursuant to supply and/or processing agreements.

The decrease in total feedstock runs for the three months ended June 30, 2017, as compared to the same period in 2016, is due primarily to decreased feedstock runs at the Superior refinery as a result of turnaround activities completed in the second quarter 2017.

The decrease in total feedstock runs for the six months ended June 30, 2017, as compared to the same period in 2016, is due primarily to decreased feedstock runs at the Superior refinery as a result of turnaround activities completed in the second quarter 2017 partially offset by improved operational reliability.

(3) Total facility production represents the bpd of specialty products and fuel products yielded from processing crude oil and other feedstocks at our facilities and at certain third-party facilities pursuant to supply and/or processing agreements. The difference between total facility production and total feedstock runs is primarily a result of the time lag between the input of feedstocks and production of finished products and volume loss.

The change in total facility production for the three and six months ended June 30, 2017, as compared to the same periods in 2016, is due primarily to the operational items discussed above in footnote 2.

(4) Packaged and synthetic specialty products include production at the Royal Purple, Bel-Ray, Calumet Packaging and Missouri facilities.

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The following table reflects our consolidated results of operations and includes the non-GAAP financial measures EBITDA, Adjusted EBITDA and Distributable Cash Flow. For a reconciliation of EBITDA, Adjusted EBITDA and Distributable Cash Flow to Net income (loss) and net cash used in operating activities, our most directly comparable financial performance and liquidity measures calculated and presented in accordance with GAAP, please read "—Non-GAAP Financial Measures."

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In millions)			
Sales	$1,030.9	$972.9	$1,968.3	$1,685.9
Cost of sales	870.5	841.6	1,668.4	1,468.4
Gross profit	160.4	131.3	299.9	217.5
Operating costs and expenses:				
Selling	28.2	26.2	55.7	56.7
General and administrative	33.6	24.8	65.4	52.4
Transportation	41.1	45.0	81.7	84.2
Taxes other than income taxes	4.9	4.2	10.4	9.9
Asset impairment	—	33.4	0.4	33.4
Other	1.1	0.3	3.0	2.3
Operating income (loss)	51.5	(2.6)	83.3	(21.4)
Other income (expense):				
Interest expense	(44.5)	(42.8)	(88.4)	(73.1)
Gain on derivative instruments	1.3	17.8	7.0	10.1
Loss from unconsolidated affiliates	(0.1)	(7.1)	(0.2)	(18.2)
Loss from sale of unconsolidated affiliates	—	(113.4)	—	(113.4)
Other	0.5	0.5	0.7	0.9
Total other expense	(42.8)	(145.0)	(80.9)	(193.7)
Net income (loss) before income taxes	8.7	(147.6)	2.4	(215.1)
Income tax expense (benefit)	(0.9)	0.3	(1.0)	0.5
Net income (loss)	$9.6	$(147.9)	$3.4	$(215.6)
EBITDA	$94.1	$(61.0)	$172.8	$(59.4)
Adjusted EBITDA	$101.6	$70.0	$180.3	$76.6
Distributable Cash Flow	$45.2	$31.7	$76.7	$6.6

Non-GAAP Financial Measures

We include in this Quarterly Report the non-GAAP financial measures EBITDA, Adjusted EBITDA and Distributable Cash Flow. We provide reconciliations of EBITDA, Adjusted EBITDA and Distributable Cash Flow to Net income (loss), our most directly comparable financial performance measure. We also provide a reconciliation of EBITDA, Adjusted EBITDA and Distributable Cash Flow to Net cash used in operating activities, our most directly comparable liquidity measure. Both Net loss and Net cash used in operating activities are calculated and presented in accordance with U.S. generally accepted accounting principles ("GAAP").

EBITDA, Adjusted EBITDA and Distributable Cash Flow are used as supplemental financial measures by our management and by external users of our financial statements such as investors, commercial banks, research analysts and others, to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness;
- our operating performance and return on capital as compared to those of other companies in our industry, without regard to financing or capital structure; and

- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

Management believes that these non-GAAP measures are useful to analysts and investors as they exclude transactions not related to our core cash operating activities and provide metrics to analyze our ability to pay distributions and interest costs. We believe that excluding these transactions allows investors to meaningfully analyze trends and performance of our core cash operations.

We define EBITDA for any period as net income (loss) plus interest expense (including debt issuance and extinguishment costs), income taxes and depreciation and amortization.

We define Adjusted EBITDA for any period as: (1) net income (loss) plus (2)(a) interest expense; (b) income taxes; (c) depreciation and amortization; (d) impairment; (e) unrealized losses from mark to market accounting for hedging activities; (f) realized gains under derivative instruments excluded from the determination of net income (loss); (g) non-cash equity based compensation expense and other non-cash items (excluding items such as accruals of cash expenses in a future period or amortization of a prepaid cash expense) that were deducted in computing net income (loss); (h) debt refinancing fees, premiums and penalties; (i) any net loss realized in connection with an asset sale that was deducted in computing net income (loss) and (j) all extraordinary, unusual or non-recurring items of gain or loss, or revenue or expense; minus (3)(a) unrealized gains from mark to market accounting for hedging activities; (b) realized losses under derivative instruments excluded from the determination of net income (loss) and (c) other non-recurring expenses and unrealized items that reduced net income (loss) for a prior period, but represent a cash item in the current period.

We define Distributable Cash Flow for any period as Adjusted EBITDA less replacement and environmental capital expenditures, turnaround costs, cash interest expense (consolidated interest expense less non-cash interest expense), income (loss) from unconsolidated affiliates, net of cash distributions and income tax expense (benefit). Distributable Cash Flow is used by us and our investors and analysts to analyze our ability to pay distributions. However, the indentures governing our senior notes contain covenants that, among other things, restrict our ability to pay distributions.

The definition of Adjusted EBITDA presented in this Quarterly Report is consistent with the calculation of “Consolidated Cash Flow” contained in the indentures governing our 2021 Secured, 2021, 2022 and 2023 Notes (as defined in this Quarterly Report). We are required to report Consolidated Cash Flow to the holders of our 2021 Secured, 2021, 2022 and 2023 Notes and Adjusted EBITDA to the lenders under our revolving credit facility, and these measures are used by them to determine our compliance with certain covenants governing those debt instruments. Please refer to “Liquidity and Capital Resources” within this item for additional details regarding the covenants governing our debt instruments.

The preliminary expected range for forward-looking non-GAAP Adjusted EBITDA contained in this Quarterly Report is provided only on a non-GAAP basis, due to the inherent difficulty of calculating items that would be included in Net income (loss) on a GAAP basis. Adjusted EBITDA guidance that does not include certain charges and costs, which in future periods are generally expected to be similar to the kinds of charges and costs excluded from Adjusted EBITDA in prior periods, such as interest and other non-operating items, depreciation and amortization and items that are unusual in nature or infrequently occurring. The exclusion of these charges and costs in future periods will have a significant impact on Calumet’s Adjusted EBITDA, and Calumet is not able to provide a reconciliation of its Adjusted EBITDA guidance to net income (loss) without unreasonable efforts due to the uncertainty and variability of the nature and amount of these future charges and costs.

EBITDA, Adjusted EBITDA and Distributable Cash Flow should not be considered alternatives to Net income (loss), Operating income (loss), Net cash used in operating activities or any other measure of financial performance presented in accordance with GAAP. In evaluating our performance as measured by EBITDA, Adjusted EBITDA and Distributable Cash Flow, management recognizes and considers the limitations of these measurements. EBITDA and Adjusted EBITDA do not reflect our obligations for the payment of income taxes, interest expense or other obligations such as capital expenditures. Accordingly, EBITDA, Adjusted EBITDA and Distributable Cash Flow are only three of several measurements that management utilizes. Moreover, our EBITDA, Adjusted EBITDA and Distributable Cash Flow may not be comparable to similarly titled measures of another company because all

companies may not calculate EBITDA, Adjusted EBITDA and Distributable Cash Flow in the same manner.
The following tables present a reconciliation of Net income (loss) to EBITDA, Adjusted EBITDA and Distributable Cash Flow, Segment Adjusted EBITDA to EBITDA and Net income (loss), and Distributable Cash Flow, Adjusted EBITDA and EBITDA to Net cash used in operating activities, our most directly comparable GAAP financial performance and liquidity measures, for each of the periods indicated.

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In millions)			
Reconciliation of Net income (loss) to EBITDA, Adjusted EBITDA and Distributable Cash Flow:				
Net income (loss)	$9.6	$(147.9)	$3.4	$(215.6)
Add:				
Interest expense	44.5	42.8	88.4	73.1
Depreciation and amortization	40.9	43.8	82.0	82.6
Income tax expense (benefit)	(0.9)	0.3	(1.0)	0.5
EBITDA	$94.1	$(61.0)	$172.8	$(59.4)
Add:				
Unrealized gain on derivative instruments	$(1.3)	$(23.8)	$(11.9)	$(28.4)
Realized loss on derivatives, not included in net income (loss) or settled in a prior period	—	(2.3)	—	(4.4)
Amortization of turnaround costs	6.6	8.3	14.0	17.4
Impairment charges	—	33.4	0.4	33.4
Loss on sale of unconsolidated affiliate	—	113.9	—	113.9
Non-cash equity based compensation and other non-cash items	2.2	1.5	5.0	4.1
Adjusted EBITDA	$101.6	$70.0	$180.3	$76.6
Less:				
Replacement and environmental capital expenditures [1]	$5.6	$3.3	$10.9	$11.1
Cash interest expense [2]	42.0	40.1	83.6	68.5
Turnaround costs	9.8	1.7	10.3	8.1
Loss from unconsolidated affiliates	(0.1)	(7.1)	(0.2)	(18.2)
Income tax expense (benefit)	(0.9)	0.3	(1.0)	0.5
Distributable Cash Flow	$45.2	$31.7	$76.7	$6.6

(1) Replacement capital expenditures are defined as those capital expenditures which do not increase operating capacity or reduce operating costs and exclude turnaround costs. Environmental capital expenditures include asset additions to meet or exceed environmental and operating regulations.

(2) Represents consolidated interest expense less non-cash interest expense.

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In millions)			
Reconciliation of Segment Adjusted EBITDA to EBITDA and Net income (loss):				
Segment Adjusted EBITDA				
Specialty products Adjusted EBITDA	$67.1	$59.0	$112.7	$117.5
Fuel products Adjusted EBITDA	34.0	18.9	70.8	(27.1)
Oilfield services Adjusted EBITDA	0.5	(7.9)	(3.2)	(13.8)
Total segment Adjusted EBITDA	$101.6	$70.0	$180.3	$76.6
Less:				
Unrealized gain on derivative instruments	$(1.3)	$(23.8)	$(11.9)	$(28.4)
Realized loss on derivatives, not included in net income (loss) or settled in a prior period	—	(2.3)	—	(4.4)
Amortization of turnaround costs	6.6	8.3	14.0	17.4
Impairment charges	—	33.4	0.4	33.4
Loss on sale of unconsolidated affiliate	—	113.9	—	113.9
Non-cash equity based compensation and other non-cash items	2.2	1.5	5.0	4.1
EBITDA	$94.1	$(61.0)	$172.8	$(59.4)
Less:				
Interest expense	$44.5	$42.8	$88.4	$73.1
Depreciation and amortization	40.9	43.8	82.0	82.6
Income tax expense (benefit)	(0.9)	0.3	(1.0)	0.5
Net income (loss)	$9.6	$(147.9)	$3.4	$(215.6)

	Six Months Ended June 30,	
	2017	2016
	(In millions)	
Reconciliation of Distributable Cash Flow, Adjusted EBITDA and EBITDA to Net cash used in operating activities:		
Distributable Cash Flow	$76.7	$6.6
Add:		
Replacement and environmental capital expenditures [1]	10.9	11.1
Cash interest expense [2]	83.6	68.5
Turnaround costs	10.3	8.1
Loss from unconsolidated affiliates	(0.2)	(18.2)
Income tax expense (benefit)	(1.0)	0.5
Adjusted EBITDA	$180.3	$76.6
Less:		
Unrealized gain on derivative instruments	$(11.9)	$(28.4)
Realized loss on derivatives, not included in net income (loss) or settled in a prior period	—	(4.4)
Amortization of turnaround costs	14.0	17.4
Impairment charges	0.4	33.4
Loss on sale of unconsolidated affiliate	—	113.9
Non-cash equity based compensation and other non-cash items	5.0	4.1
EBITDA	$172.8	$(59.4)
Add:		
Unrealized gain on derivative instruments	$(11.9)	$(28.4)
Cash interest expense [2]	(83.6)	(68.5)
Asset impairment	0.4	33.4
Non-cash equity based compensation	3.3	2.9
Lower of cost or market inventory adjustment	(8.0)	(44.4)
Deferred income tax (benefit) expense	0.1	(0.2)
Loss from unconsolidated affiliates	0.2	18.2
Loss on sale of unconsolidated affiliates	—	113.4
Amortization of turnaround costs	14.0	17.4
Income tax benefit (expense)	1.0	(0.5)
Provision for doubtful accounts	0.1	0.5
Changes in assets and liabilities:		
Accounts receivable	(50.7)	(60.0)
Inventories	(44.3)	(10.3)
Other current assets	(2.1)	(1.5)
Derivative activity	(0.3)	(10.4)
Turnaround costs	(10.3)	(8.1)
Other assets	—	(0.4)
Accounts payable	24.2	35.1
Accrued interest payable	(0.1)	9.1
Other current liabilities	(44.8)	9.7
Other, including changes in noncurrent liabilities	4.4	0.7
Net cash used in operating activities	$(35.6)	$(51.7)

[1] Replacement capital expenditures are defined as those capital expenditures which do not increase operating capacity or reduce operating costs and exclude turnaround costs. Environmental capital expenditures include asset

additions to meet or exceed environmental and operating regulations.

(2) Represents consolidated interest expense less non-cash interest expense.

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Changes in Results of Operations for the Three Months Ended June 30, 2017 and 2016

Sales. Sales increased $58.0 million, or 6.0%, to $1,030.9 million in the three months ended June 30, 2017, from $972.9 million in the same period in 2016. Sales for each of our principal product categories in these periods were as follows:

	Three Months Ended June 30,		
	2017	2016	% Change
	(Dollars in millions, except barrel and per barrel data)		
Sales by segment:			
Specialty products:			
Lubricating oils	$ 153.1	$ 146.3	4.6 %
Solvents	68.6	61.1	12.3 %
Waxes	29.0	36.3	(20.1)%
Packaged and synthetic specialty products (1)	83.1	76.6	8.5 %
Other (2)	9.3	12.1	(23.1)%
Total specialty products	$ 343.1	$ 332.4	3.2 %
Total specialty products sales volume (in barrels)	2,460,000	2,760,000	(10.9)%
Average specialty products sales price per barrel	$ 139.47	$ 120.43	15.8 %
Fuel products:			
Gasoline	$ 247.4	$ 228.0	8.5 %
Diesel	210.2	223.5	(6.0)%
Jet fuel	32.8	25.8	27.1 %
Asphalt, heavy fuel oils and other (3)	133.5	126.8	5.3 %
Hedging activities	—	15.1	(100.0)%
Total fuel products	$ 623.9	$ 619.2	0.8 %
Total fuel products sales volume (in barrels)	10,385,000	11,280,000	(7.9)%
Average fuel products sales price per barrel (excluding hedging activities)	$ 60.08	$ 53.55	12.2 %
Average fuel products sales price per barrel (including hedging activities)	$ 60.08	$ 54.89	9.5 %
Total oilfield services	$ 63.9	$ 21.3	200.0 %
Total sales	$ 1,030.9	$ 972.9	6.0 %
Total specialty and fuel products sales volume (in barrels)	12,845,000	14,040,000	(8.5)%

(1) Represents packaged and synthetic specialty products at the Royal Purple, Bel-Ray, Calumet Packaging and Missouri facilities.

(2) Represents fuels and asphalt, produced in connection with the production of specialty products at the Princeton and Cotton Valley refineries and Dickinson and Karns City facilities.

(3) Represents asphalt, heavy fuel oils and other products produced in connection with the production of fuels at the Shreveport, Superior, San Antonio and Great Falls refineries and crude oil sales from the Superior and San Antonio refineries to third-party customers.

The components of the $10.7 million increase in specialty products segment sales for the three months ended June 30, 2017, as compared to the three months ended June 30, 2016, were as follows:

	Dollar Change (In millions)
Sales price	$ 46.8

Volume	(36.1)
Total specialty products segment sales increase	$ 10.7

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Specialty products segment sales increased $10.7 million period over period, or 3.2%, primarily due to an increase in the average selling price per barrel, partially offset by decreased sales volume. Sales increased $46.8 million compared to the second quarter 2016 due to a 15.8% increase in the average selling price per barrel primarily as a result of higher lubricating oils and solvents average selling prices due to market conditions, while the average cost of crude oil per barrel increased 7.1%. The decrease in sales volume is due primarily to lower sales volume of lubricating oils and waxes, partially offset by increased sales volume of branded and packaged products due to market conditions.

The components of the $4.7 million increase in fuel products segment sales for the three months ended June 30, 2017, as compared to the three months ended June 30, 2016, were as follows:

	Dollar Change (In millions)
Sales price	$ 67.8
Hedging activities	(15.1)
Volume	(48.0)
Total fuel products segment sales increase	$ 4.7

Fuel products segment sales increased $4.7 million period over period, or 0.8%, primarily due to an increase in the average selling price per barrel, partially offset by decreased sales volume and a $15.1 million decrease in realized derivative gains recorded in sales on our fuel products. The average selling price per barrel (excluding the impact of hedging activities reflected in sales) increased $6.53, or 12.2%, resulting in a $67.8 million increase in sales, compared to a 9.1% increase in the average cost of crude oil per barrel. The increase in the average selling price per barrel is primarily due to market conditions. Sales volume decreased 7.9% primarily due to decreased sales volume of diesel and asphalt as a result of turnaround activities at the Superior refinery.

Oilfield services segment sales increased $42.6 million period over period, or 200.0%, primarily due to higher sales volume driven by an increase in rig count. Our rig count increased 145% primarily as a result of a 112.0% increase in the U.S. land-based rig count. Currently, we sell to approximately 10% of the U.S. land-based rigs. Increases in crude oil and natural gas prices impacted our customers' drilling and production activities during 2017, which resulted in a favorable impact on our sales in 2017.

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Gross Profit. Gross profit increased $29.1 million, or 22.2%, to $160.4 million in the three months ended June 30, 2017, from $131.3 million in the same period in 2016. Gross profit for our specialty products, fuel products and oilfield services segments were as follows:

	Three Months Ended June 30,					
	2017		2016		% Change	
	(Dollars in millions, except per barrel data)					
Gross profit by segment:						
Specialty products:						
Gross profit	$ 103.0		$ 98.5		4.6	%
Percentage of sales	30.0	%	29.6	%		
Specialty products gross profit per barrel	$ 41.87		$ 35.69		17.3	%
Fuel products:						
Gross profit excluding hedging activities	$ 40.7		$ 29.2		39.4	%
Hedging activities	—		2.8		(100.0	)%
Gross profit	$ 40.7		$ 32.0		27.2	%
Percentage of sales	6.5	%	5.2	%		
Fuel products gross profit per barrel (excluding hedging activities)	$ 3.92		$ 2.59		51.4	%
Fuel products gross profit per barrel (including hedging activities)	$ 3.92		$ 2.84		38.0	%
Oilfield services:						
Gross profit	$ 16.7		$ 0.8		1,987.5	%
Percentage of sales	26.1	%	3.8	%		
Total gross profit	$ 160.4		$ 131.3		22.2	%
Percentage of sales	15.6	%	13.5	%		

The components of the $4.5 million increase in specialty products segment gross profit for the three months ended June 30, 2017, as compared to the three months ended June 30, 2016, were as follows:

	Dollar Change (In millions)	
Three months ended June 30, 2016 reported gross profit	$ 98.5	
Sales price	46.8	
LCM inventory adjustment	(17.8	)
Volume	(15.8	)
Cost of materials	(6.9	)
Operating costs	(1.8	)
Three months ended June 30, 2017 reported gross profit	$ 103.0	

The increase in specialty products segment gross profit of $4.5 million for the three months ended June 30, 2017, as compared to the same period in 2016, was due primarily to an increase in the average selling price per barrel, partially offset by a $17.8 million decrease in the favorable LCM inventory adjustment, decreased sales volume and increased cost of materials. Sales price and cost of materials, net, increased gross profit by $39.9 million, as the average selling price per barrel increased 15.8%, while the average cost of crude oil per barrel only increased 7.1%. The decrease in sales volume is due primarily to lower sales volume of lubricating oils and waxes, partially offset by increased sales volume of branded and packaged products due to market conditions.

The components of the $8.7 million increase in fuel products segment gross profit for the three months ended June 30, 2017, as compared to the three months ended June 30, 2016, were as follows:

	Dollar Change (In millions)
Three months ended June 30, 2016 reported gross profit	$ 32.0
Sales price	67.8
RINs expense	24.5
Cost of materials	(53.4)
LCM inventory adjustment	(13.6)
Volume	(9.8)
Operating costs	(4.0)
Hedging activities	(2.8)
Three months ended June 30, 2017 reported gross profit	$ 40.7

The increase in fuel products segment gross profit of $8.7 million for the three months ended June 30, 2017, as compared to the same period in 2016, was due primarily to widening crack spreads and a $24.5 million decrease in RINs expense, partially offset by a $13.6 million decrease in the favorable LCM inventory adjustment and decreased sales volume. During the second quarter 2017 period, the average cost of crude oil per barrel increased 9.1% and the average selling price per barrel (excluding the impact of hedging activities reflected in sales) increased by 12.2%. The $24.5 million decrease in RINs expense primarily resulted from a reduction of the RINs liability as result of an approval from the EPA of the small refinery exemption from the requirements of the RFS for certain of our refineries for the 2016 calendar year and decreased RINs market pricing. The increase in operating costs was primarily due to increased repairs and maintenance and natural gas costs, partially offset by lower depreciation and amortization expense. The decrease in sales volume is due primarily to turnaround activities at the Superior refinery.

The increase in oilfield services segment gross profit of $15.9 million for the three months ended June 30, 2017, as compared to the same period in 2016, was due primarily to increased sales volume driven by an increase in rig count. Increases in crude oil and natural gas prices resulted in improvement in our customers' drilling and production activities, which had a favorable impact on gross profit in 2017. In addition, the continued increase in crude oil prices created pricing expansion in the basins in which we operate.

Selling. Selling expenses increased $2.0 million, or 7.6%, to $28.2 million in the three months ended June 30, 2017, from $26.2 million in the same period in 2016. The increase was due primarily to a $4.5 million increase in contract services as a result of increased rig count, partially offset by a decrease of $1.4 million in depreciation and amortization and a $1.1 million decrease in salaries and benefits.

General and administrative. General and administrative expenses increased $8.8 million, or 35.5%, to $33.6 million in the three months ended June 30, 2017, from $24.8 million in the same period in 2016. The increase was primarily due to a $7.1 million increase in incentive compensation costs and a $1.9 million increase in professional fees expense.

Transportation. Transportation expenses decreased $3.9 million, or 8.7%, to $41.1 million in the three months ended June 30, 2017, from $45.0 million in the same period in 2016. This decrease was due primarily to decreased freight rates and decreased specialty products sales volume, partially offset by increased drilling and production activities by our customers in the oilfield services segment.

Asset impairment. During the three months ended June 30, 2016, we recorded a goodwill impairment charge of $33.4 million related to the fuel products segment. The impairment charge was primarily a result of the reduced outlook on crack spreads. There was no impairment charge in the comparable 2017 period.

Interest expense. Interest expense increased $1.7 million, or 4.0%, to $44.5 million in the three months ended June 30, 2017, from $42.8 million in the same period in 2016, due primarily to an increase in interest related to the senior secured notes issued in April 2016, partially offset by increased capitalized interest as a result of increased capital spending.

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Derivative activity. The following table details the impact of our derivative instruments on the unaudited condensed consolidated statements of operations for the three months ended June 30, 2017 and 2016:

	Three Months Ended June 30, 2017	2016
	(In millions)	
Derivative gain reflected in sales	$—	$15.1
Derivative loss reflected in cost of sales	—	(12.8)
Derivative gain reflected in gross profit	$—	$2.3
Realized loss on derivative instruments	$—	$(6.0)
Unrealized gain on derivative instruments	1.3	23.8
Total derivative gain reflected in the unaudited condensed consolidated statements of operations	$1.3	$20.1
Total loss on commodity derivative settlements	$—	$(6.0)

Gain on derivative instruments. Gain on derivative instruments decreased $16.5 million to $1.3 million in the three months ended June 30, 2017, from $17.8 million in the prior year period. The change was primarily due to a $22.5 million decrease in unrealized gains, partially offset by a $6.0 million decrease in realized losses. The decrease in realized losses was primarily related to settlements of derivative instruments used to economically hedge crude oil and natural gas swaps in the 2016 period that are not classified as hedges for accounting purposes. The decrease in unrealized gains was primarily related to derivative instruments used to economically hedge natural gas, crack spreads and crude oil that are not classified as hedges for accounting purposes.

Loss from unconsolidated affiliates. Loss from unconsolidated affiliates decreased $7.0 million to $0.1 million in the three months ended June 30, 2017, from $7.1 million in the same period in 2016, due primarily to the sale of our 50% interest in Dakota Prairie Refining, LLC (“Dakota Prairie”) in June 2016.

Loss on sale of unconsolidated affiliates. Loss on sale of unconsolidated affiliates was $113.4 million in the three months ended June 30, 2016. The loss on sale of unconsolidated affiliates was primarily due to the $113.9 million loss on sale of Dakota Prairie in June 2016. There was no loss on sale of unconsolidated affiliates in the three months ended June 30, 2017.

Income tax expense (benefit). Income tax benefit increased $1.2 million to a benefit of $0.9 million in the three months ended June 30, 2017, from an expense of $0.3 million in the prior year period. The change was due primarily to a state income tax refund received in the 2017 period.

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Changes in Results of Operations for the Six Months Ended June 30, 2017 and 2016

Sales. Sales increased $282.4 million, or 16.8%, to $1,968.3 million in the six months ended June 30, 2017, from $1,685.9 million in the same period in 2016. Sales for each of our principal product categories in these periods were as follows:

	Six Months Ended June 30,		
	2017	2016	% Change
	(Dollars in millions, except barrel and per barrel data)		
Sales by segment:			
Specialty products:			
Lubricating oils	$ 304.4	$ 275.5	10.5 %
Solvents	136.1	117.0	16.3 %
Waxes	60.0	63.5	(5.5)%
Packaged and synthetic specialty products [(1)]	161.5	157.5	2.5 %
Other [(2)]	18.3	19.6	(6.6)%
Total specialty products	$ 680.3	$ 633.1	7.5 %
Total specialty products sales volume (in barrels)	5,010,000	5,120,000	(2.1)%
Average specialty products sales price per barrel	$ 135.79	$ 123.65	9.8 %
Fuel products:			
Gasoline	$ 475.6	$ 390.2	21.9 %
Diesel	417.0	346.4	20.4 %
Jet fuel	70.4	49.2	43.1 %
Asphalt, heavy fuel oils and other [(3)]	210.2	182.2	15.4 %
Hedging activities	—	31.1	(100.0)%
Total fuel products	$ 1,173.2	$ 999.1	17.4 %
Total fuel products sales volume (in barrels)	19,487,000	20,244,000	(3.7)%
Average fuel products sales price per barrel (excluding hedging activities)	$ 60.20	$ 47.82	25.9 %
Average fuel products sales price per barrel (including hedging activities)	$ 60.20	$ 49.35	22.0 %
Total oilfield services	$ 114.8	$ 53.7	113.8 %
Total sales	$ 1,968.3	$ 1,685.9	16.8 %
Total specialty and fuel products sales volume (in barrels)	24,497,000	25,364,000	(3.4)%

(1) Represents packaged and synthetic specialty products at the Royal Purple, Bel-Ray, Calumet Packaging and Missouri facilities.

(2) Represents fuels and asphalt produced in connection with the production of specialty products at the Princeton and Cotton Valley refineries and Dickinson and Karns City facilities.

(3) Represents asphalt, heavy fuel oils and other products produced in connection with the production of fuels at the Shreveport, Superior, San Antonio and Great Falls refineries and crude oil sales from the Superior, San Antonio and Shreveport refineries to third-party customers.

The components of the $47.2 million increase in specialty products segment sales for the six months ended June 30, 2017, as compared to the six months ended June 30, 2016, were as follows:

	Dollar Change (In millions)
Sales price	$ 60.8

Volume	(13.6)
Total specialty products segment sales increase	$ 47.2

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Specialty products segment sales increased $47.2 million period over period, or 7.5%, primarily due to an increase in the average selling price per barrel, partially offset by lower sales volume. Sales increased $60.8 million compared to the same period in 2016 due to a 9.8% increase in the average selling price per barrel, primarily as a result of increased lubricating oils and solvents average selling prices due to market conditions, while the average cost of crude oil per barrel increased 25.6%. The decrease in sales volume is due primarily to lower sales volume of lubricating oils, solvents and waxes, partially offset by higher sales volume of branded and packaged products due to market conditions.

The components of the $174.1 million increase in fuel products segment sales for the six months ended June 30, 2017, as compared to the six months ended June 30, 2016, were as follows:

	Dollar Change (In millions)
Sales price	$ 241.4
Volume	(36.2)
Hedging activities	(31.1)
Total fuel products segment sales increase	$ 174.1

Fuel products segment sales increased $174.1 million period over period, or 17.4%, primarily due to an increase in the average selling price per barrel, partially offset by a decrease in sales volume and a $31.1 million decrease in realized derivative gains recorded in sales on our fuel products. The average selling price per barrel (excluding the impact of hedging activities reflected in sales) increased $12.38, or 25.9%, resulting in a $241.4 million increase in sales, compared to a 30.0% increase in the average cost of crude oil per barrel. The increase in the average selling price per barrel is primarily due to market conditions. Sales volume decreased 3.7% primarily due to decreased sales volume of gasoline, diesel and asphalt, partially offset by increased sales volume of jet fuel primarily due to market conditions and turnaround activities at the Superior refinery.

Oilfield services segment sales increased $61.1 million period over period, or 113.8%, primarily due to increased sales volume driven by an increase in rig count. Our rig count increased 104% primarily as a result of a 69% increase in the U.S. land-based rig count. Currently, we sell to approximately 10% of the U.S. land-based rigs. Increases in crude oil and natural gas prices impacted our customers' drilling and production activities during 2017, resulting in an increase in net sales year-over-year.

Gross Profit. Gross profit increased $82.4 million, or 37.9%, to $299.9 million in the six months ended June 30, 2017, from $217.5 million in the same period in 2016. Gross profit for our specialty, fuel products and oilfield services segments was as follows:

	Six Months Ended June 30,		
	2017	2016	% Change
	(Dollars in millions, except per barrel data)		
Gross profit by segment:			
Specialty products:			
Gross profit	$ 185.3	$ 197.8	(6.3)%
Percentage of sales	27.2 %	31.2 %	
Specialty products gross profit per barrel	$ 36.99	$ 38.63	(4.2)%
Fuel products:			
Gross profit excluding hedging activities	$ 87.9	$ 7.4	1,087.8 %
Hedging activities	—	5.6	(100.0)%
Gross profit	$ 87.9	$ 13.0	576.2 %
Percentage of sales	7.5 %	1.3 %	
Fuel products gross profit per barrel (excluding hedging activities)	$ 4.51	$ 0.37	1,118.9 %
Fuel products gross profit per barrel (including hedging activities)	$ 4.51	$ 0.64	604.7 %
Oilfield services:			

Gross profit	$ 26.7		$ 6.7		298.5	%
Percentage of sales	23.3	%	12.5	%		
Total gross profit	$ 299.9		$ 217.5		37.9	%
Percentage of sales	15.2	%	12.9	%		

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The components of the $12.5 million decrease in specialty products segment gross profit for the six months ended June 30, 2017, as compared to the six months ended June 30, 2016, were as follows:

	Dollar Change (In millions)
Six months ended June 30, 2016 reported gross profit	$ 197.8
Cost of materials	(44.1)
LCM inventory adjustment	(21.9)
Volume	(6.4)
Operating costs	(0.9)
Sales price	60.8
Six months ended June 30, 2017 reported gross profit	$ 185.3

The decrease in specialty products segment gross profit of $12.5 million for the six months ended June 30, 2017, as compared to the same period in 2016, was primarily due to increased cost of materials, a $21.9 million decrease in the favorable LCM inventory adjustment and decreased sales volume, partially offset by an increase in the average selling price per barrel. Sales price and cost of materials, net, increased gross profit by $16.7 million, as the average selling price per barrel increased 9.8%, while the average cost of crude oil per barrel increased 25.6%. The decrease in sales volume is primarily related to decreased lubricating oils, waxes and solvents sales volume, partially offset by increased branded and packaged sales volume due to market conditions.

The components of the $74.9 million increase in fuel products segment gross profit for the six months ended June 30, 2017, as compared to the six months ended June 30, 2016, were as follows:

	Dollar Change (In millions)
Six months ended June 30, 2016 reported gross profit	$ 13.0
Sales price	241.4
RINs expense	88.5
Cost of materials	(224.8)
LCM inventory adjustment	(11.8)
Volume	(7.7)
Hedging activities	(5.6)
Operating costs	(5.1)
Six months ended June 30, 2017 reported gross profit	$ 87.9

The increase in fuel products segment gross profit of $74.9 million for the six months ended June 30, 2017, as compared to the same period in 2016, was primarily due to widening crack spreads and an $88.5 million decrease in RINs expense, partially offset by an $11.8 million decrease in the favorable LCM inventory adjustment, a $5.6 million decrease in realized derivative gains on our fuel products and a $5.1 million increase in operating costs. During the 2017 period, the average cost of crude oil per barrel increased 30.0%, while the average selling price per barrel (excluding the impact of hedging activities reflected in sales) increased by 25.9%. The $88.5 million decrease in RINs expense primarily resulted from decreased a reduction of the RINs liability as result of an approval from the EPA of the small refinery exemption from the requirements of the RFS for certain of our refineries for the 2016 calendar year and decreased RINs market pricing. The increase in operating costs was primarily due to increased depreciation expense and natural gas costs, partially offset by decreased repairs and maintenance.

The increase in oilfield services segment gross profit of $20.0 million for the six months ended June 30, 2017, as compared to the same period in 2016, was primarily due to increased sales volume driven by an increase in rig count, partially offset by a $2.7 million decrease in the favorable LCM inventory adjustment. Increases in crude oil and natural gas prices resulted in improvement in our customers’ drilling and production activities, which had a favorable impact on our gross profit in 2017. In addition, the continued increase in crude oil prices created pricing expansion in the basins in which we operate.

Selling. Selling expenses decreased $1.0 million, or 1.8% to $55.7 million in the six months ended June 30, 2017, from $56.7 million in the same period in 2016. The decrease was primarily due to a $4.1 million decrease in salaries and benefits primarily as a result of workforce reductions, a $2.8 million decrease in depreciation and amortization and a $0.6 million decrease in advertising expenses, partially offset by a $7.0 million increase in contract services as a result of increased rig count.

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General and administrative. General and administrative expenses increased $13.0 million, or 24.8%, to $65.4 million in the six months ended June 30, 2017, from $52.4 million in the same period in 2016. The increase was primarily due to an $11.9 million increase in incentive compensation costs, a $1.1 million increase in salaries and benefits and a $1.1 million increase in professional fees, partially offset by a $2.0 million decrease in depreciation and amortization.

Transportation. Transportation expenses decreased $2.5 million, or 3.0%, to $81.7 million in the six months ended June 30, 2017, from $84.2 million in the same period in 2016. This decrease was primarily due to decreased freight rates and decreased specialty products sales volume, partially offset by increased drilling and production activities by our customers in the oilfield services segment.

Asset impairment. Asset impairment decreased $33.0 million, or 98.8%, to $0.4 million in six months ended June 30, 2017, from $33.4 million in same period in 2016. The change was primarily due to a goodwill impairment charge of $33.4 million in the 2016 period related to the fuel products segment. The impairment charge was primarily a result of the reduced outlook on crack spreads.

Interest expense. Interest expense increased $15.3 million, or 20.9%, to $88.4 million in the six months ended June 30, 2017, from $73.1 million in the same period in 2016, primarily due to an increase in the amount of our outstanding long-term debt, higher interest rates on senior secured notes issued in April 2016 compared to other outstanding long-term debt and decreased capitalized interest as a result of decreased capital spending.

Derivative activity. The following table details the impact of our derivative instruments on the unaudited condensed consolidated statements of operations for the six months ended June 30, 2017 and 2016:

	Six Months Ended June 30,	
	2017	2016
	(In millions)	
Derivative gain reflected in sales	$—	$31.1
Derivative loss reflected in cost of sales	—	(26.7)
Derivative gain reflected in gross profit	$—	$4.4
Realized loss on derivative instruments	$(4.9)	$(18.3)
Unrealized gain on derivative instruments	11.9	28.4
Total derivative gain reflected in the unaudited condensed consolidated statements of operations	$7.0	$14.5
Total loss on commodity derivative settlements	$(4.9)	$(18.3)

Gain on derivative instruments. Gain on derivative instruments decreased $3.1 million to $7.0 million in the six months ended June 30, 2017, from $10.1 million in the prior year period. The change was primarily due to a $16.5 million decrease in unrealized gains, partially offset by a $13.4 million decrease in realized losses. The decrease in unrealized gains was primarily related to market conditions associated with derivative instruments used to economically hedge natural gas, crack spreads and crude oil that are not classified as hedges for accounting purposes. The decrease in realized losses was primarily related to settlements of derivative instruments used to economically hedge natural gas, crude oil and natural gas swaps that are not classified as hedges for accounting purposes.

Loss from unconsolidated affiliates. Loss from unconsolidated affiliates decreased $18.0 million to $0.2 million in the six months ended June 30, 2017, from $18.2 million in the same period in 2016, primarily due to the sale of our 50% interest in Dakota Prairie in June 2016.

Loss on sale of unconsolidated affiliates. Loss on sale of unconsolidated affiliates was $113.4 million in the six months ended June 30, 2016. The loss on sale of unconsolidated affiliates was primarily due to the $113.9 million loss on sale of Dakota Prairie in June 2016. There was no loss on sale of unconsolidated affiliates in the six months ended June 30, 2017.

Income tax expense (benefit). Income tax expense (benefit) increased $1.5 million to a benefit of $1.0 million in the six months ended June 30, 2017, from an expense of $0.5 million in the prior year period. The change was due primarily to a state income tax refund received in the 2017 period.

Seasonality

The operating results for the fuel products segment, including the selling prices of asphalt products we produce, generally follow seasonal demand trends. Asphalt demand is generally lower in the first and fourth quarters of the year, as compared to the second and third quarters, due to the seasonality of the road construction and roofing industries we supply. Demand for gasoline and diesel is generally higher during the summer months than during the winter months due to seasonal increases in highway

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traffic. In addition, our natural gas costs can be higher during the winter months, as demand for natural gas as a heating fuel increases during the winter. As a result, our operating results for the first and fourth calendar quarters may be lower than those for the second and third calendar quarters of each year due to seasonality related to these and other products that we produce and sell.

The operating results for the oilfield services segment follow seasonal changes in weather and significant weather events can temporarily affect the performance and delivery of our oilfield services and products. The severity and duration of the winter can have a significant impact on drilling activity. Additionally, customer spending patterns for other oilfield services and products can result in lower activity in the fourth quarter.

Liquidity and Capital Resources

General

The following should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources" included under Part II, Item 7 in our 2016 Annual Report. There have been no material changes in that information other than as discussed below. Also, see Note 6 — "Inventory Financing Agreements" and Note 7 — "Long-Term Debt" under Part I, Item 1 "Financial Statements — Notes to Unaudited Condensed Consolidated Financial Statements" in this Quarterly Report for additional discussions related to our Supply and Offtake Agreements and our long-term debt.

Our principal sources of cash have historically included cash flow from operations, proceeds from public equity offerings, proceeds from notes offerings and bank borrowings. Principal uses of cash have included capital expenditures, acquisitions, distributions to our limited partners and general partner and debt service.

In general, we expect that our short-term liquidity needs including debt service, working capital, replacement and environmental capital expenditures and capital expenditures related to internal growth projects, will be met primarily through projected cash flow from operations, borrowings under our revolving credit facility and asset sales.

Cash Flows from Operating, Investing and Financing Activities

We are subject to business and operational risks that could materially adversely affect our cash flows. A material decrease in our cash flow from operations, including a significant, sudden decrease in crude oil prices, would likely produce a corollary material adverse effect on our borrowing capacity under our revolving credit facility and potentially our ability to comply with the covenants under our revolving credit facility. A significant, sudden increase in crude oil prices, if sustained, would likely result in increased working capital requirements which would be funded by borrowings under our revolving credit facility. In addition, our cash flow from operations may be impacted by the timing of settlement of our derivative activities. Gains and losses from derivative instruments that qualify as effective cash flow hedges are deferred in accumulated other comprehensive loss, but may impact operating cash flow in the period settled. Gains and losses from derivative instruments that do not qualify as hedges will impact operating cash flow in the period settled.

The following table summarizes our primary sources and uses of cash in each of the periods presented:

	Six Months Ended June 30,	
	2017	2016
	(In millions)	
Net cash used in operating activities	$(35.6)	$(51.7)
Net cash used in investing activities	(30.0)	(98.8)
Net cash provided by financing activities	88.0	177.1
Net increase in cash and cash equivalents	$22.4	$26.6

Operating Activities. Operating activities used cash of $35.6 million during the six months ended June 30, 2017, compared to using cash of $51.7 million during the same period in 2016. The change is primarily due to increased net income of $219.0 million, partially offset by increased working capital requirements of $91.1 million and a decrease in non-cash items of $111.8 million. Working capital increases were primarily driven by decreased other liabilities due to decreased RINs costs and increased inventories, partially offset by increased accrued salaries and wages.

Investing Activities. Cash used in investing activities decreased to $30.0 million during the six months ended June 30, 2017, compared to $98.8 million used during the prior year period. The decrease is primarily due to a decrease in capital expenditures of $57.9 million primarily due to the completion of several capital improvement projects in 2016 and decreased net investments in unconsolidated affiliates of $12.8 million.

Financing Activities. Financing activities provided cash of $88.0 million in the six months ended June 30, 2017, compared to providing $177.1 million during the prior year period. This decrease is primarily due to net proceeds from the private placement

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of senior notes of $385.3 million in 2016 with no comparable transaction in 2017, partially offset by $105.4 million of proceeds from inventory financing agreements in 2017, decreased repayments on the revolving credit facility of $101.1 million, a decrease in distributions to unitholders of $57.4 million and repayment on the related party debt of $34.5 million in 2016.

Supply and Offtake Agreements

On March 31, 2017, we entered into several agreements with Macquarie Energy North America Trading Inc. (“Macquarie”) to support the operations of our Great Falls refinery (the “Great Falls Supply and Offtake Agreements”). The Great Falls Supply and Offtake Agreements expire on October 31, 2019. On July 27, 2017, we amended the Great Falls Supply and Offtake Agreements to provide Macquarie the option to terminate the Great Falls Supply and Offtake Agreements with nine months notice any time prior to June 2019.

On June 19, 2017, we entered into several agreements with Macquarie to support the operations of the Shreveport refinery (the “Shreveport Supply and Offtake Agreements”, and together with the Great Falls Supply and Offtake Agreements, the “Supply and Offtake Agreements”). The Shreveport Supply and Offtake Agreements expire on June 2020; however, Macquarie has the option to terminate the Shreveport Supply and Offtake Agreements with nine months notice any time prior to June 2019.

At the commencement of the Great Falls Supply and Offtake Agreements, we sold to Macquarie inventory comprised of 652,000 barrels of crude oil and refined products valued at $32.2 million.

At the commencement of the Shreveport Supply and Offtake Agreements, we sold to Macquarie inventory comprised of 987,000 barrels of crude oil and refined products valued at $54.8 million.

In addition, we incurred approximately $3.0 million of costs related to the Supply and Offtake Agreements.

The Supply and Offtake Agreements are subject to minimum and maximum inventory levels. The agreements also provide for the lease to Macquarie of crude oil and certain refined product storage tanks located at the Great Falls and Shreveport refineries. Following expiration or termination of the agreements, Macquarie has the option to require us to purchase the crude oil and refined product inventories then owned by Macquarie and located at the leased storage tanks at then current market prices. Our obligations under the agreements are secured by the inventory included in these agreements.

Capital Expenditures

Our property, plant and equipment capital expenditure requirements consist of capital improvement expenditures, replacement capital expenditures, environmental capital expenditures and turnaround capital expenditures. Capital improvement expenditures include expenditures to acquire assets to grow our business, to expand existing facilities, such as projects that increase operating capacity, or to reduce operating costs. Replacement capital expenditures replace worn out or obsolete equipment or parts. Environmental capital expenditures include asset additions to meet or exceed environmental and operating regulations. Turnaround capital expenditures represent capitalized costs associated with our periodic major maintenance and repairs.

The following table sets forth our capital improvement expenditures, replacement capital expenditures, environmental capital expenditures, turnaround capital expenditures and joint venture contributions in each of the periods shown (including capitalized interest):

	Six Months Ended June 30,	
	2017	2016
	(In millions)	
Capital improvement expenditures	$11.6	$40.8
Replacement capital expenditures	6.5	7.9
Environmental capital expenditures	4.4	3.2
Turnaround capital expenditures	10.3	8.1
Joint venture contributions, net [1]	—	12.8
Total	$32.8	$72.8

(1) Includes proceeds from sale of unconsolidated affiliates.

We estimate our capital expenditures will be between $110 million and $130 million in 2017. We anticipate that capital expenditure requirements will be provided primarily through cash flow from operations, cash on hand, available borrowings under our revolving credit facility and by accessing capital markets as necessary. If future capital expenditures require expenditures in excess of our then-current cash flow from operations and borrowing availability under our existing revolving credit facility, we may be required to issue debt or equity securities in public or private offerings or incur additional borrowings under bank credit facilities to meet those costs.

Debt and Credit Facilities

As of June 30, 2017, our primary debt and credit instruments consisted of a:

- $900.0 million senior secured revolving credit facility maturing in July 2019, subject to borrowing base limitations, with a maximum letter of credit sublimit equal to $600.0 million, which amount may be increased to 90% of revolver commitments in effect with the consent of the Agent ("revolving credit facility");
- $400.0 million of 11.50% senior secured notes due 2021 ("2021 Secured Notes");
- $900.0 million of 6.50% senior notes due 2021 ("2021 Notes");
- $350.0 million of 7.625% senior notes due 2022 ("2022 Notes"); and
- $325.0 million of 7.75% senior notes due 2023 ("2023 Notes").

We were in compliance with all covenants under the debt instruments in place as of June 30, 2017, and believe we have adequate liquidity to conduct our business.

Short Term Liquidity

As of June 30, 2017, our principal sources of short-term liquidity were (i) $342.1 million of availability under our revolving credit facility, (ii) inventory financing agreements related to the Great Falls and Shreveport refineries and (iii) $26.6 million of cash. Borrowings under our revolving credit facility can be used for, among other things, working capital, capital expenditures and other lawful partnership purposes including acquisitions.

Borrowings under the revolving credit facility are limited to a borrowing base that is determined based on advance rates of percentages of Eligible Accounts and Eligible Inventory (each as defined in the revolving credit agreement). As such, the borrowing base can fluctuate based on changes in selling prices of our products and our current material costs, primarily the cost of crude oil. On June 30, 2017, we had availability on our revolving credit facility of $342.1 million, based on a $439.6 million borrowing base, $97.1 million in outstanding standby letters of credit and $0.4 million of outstanding borrowings. The borrowing base cannot exceed the revolving credit facility commitments then in effect. The lender group under our revolving credit facility is comprised of a syndicate of fifteen lenders with total commitments of $900.0 million. The lenders under our revolving credit facility have a first priority lien on our accounts receivable, certain inventory and substantially all of our cash.

Amounts outstanding under our revolving credit facility can fluctuate materially during each quarter mainly due to cash flow from operations, normal changes in working capital, payments of quarterly distributions to unitholders, capital expenditures and debt service costs. Specifically, the amount borrowed under our revolving credit facility is typically at its highest level after we pay for the majority of our crude oil supply on the 20th day of every month per standard industry terms. The maximum revolving credit facility borrowings during the quarter ended June 30, 2017, were $112.5 million. Our availability under our revolving credit facility during the peak borrowing days of the quarter has been sufficient to support our operations and service upcoming requirements. During the quarter ended June 30, 2017, availability for additional borrowings under our revolving credit facility was approximately $273.1 million at its lowest point.

The revolving credit facility currently bears interest at a rate equal to the prime rate plus a basis points margin or the LIBOR rate plus a basis points margin, at our option. As of June 30, 2017, this margin was 50 basis points for prime rate loans and 150 basis points for LIBOR rate loans; however, the margin can fluctuate quarterly based on our average availability for additional borrowings under the revolving credit facility during the preceding fiscal quarter.

In addition to paying interest on outstanding borrowings under the revolving credit facility, we are required to pay a commitment fee to the lenders under the revolving credit facility with respect to the unutilized commitments thereunder at a rate equal to either 0.250% or 0.375% per annum, depending on the average daily available unused borrowing capacity for the preceding month. We also pay a customary letter of credit fee, including a fronting fee of 0.125% per annum of the stated amount of each outstanding letter of credit, and customary agency fees.

Our revolving credit facility contains various covenants that limit, among other things, our ability to: incur indebtedness; grant liens; dispose of certain assets; make certain acquisitions and investments; redeem or prepay other debt or make other restricted payments such as distributions to unitholders; enter into transactions with affiliates; and enter into a merger, consolidation or sale of assets. The revolving credit facility generally permits us to make cash distributions to our unitholders as long as immediately after giving effect to such a cash distribution we have restricted cash and availability under the revolving credit facility totaling at least the greater of (i) 15% of the Borrowing Base (as defined in the credit agreement) then in effect and (ii) $70.0 million (which amount is subject to increase in proportion to revolving commitment increases). Further, the revolving credit facility contains one springing financial covenant which provides that only if our availability under the revolving credit facility falls below the greater of (a) 12.5% of the Borrowing Base (as defined in the credit agreement) then in effect and (b) $45.0 million (which amount is subject to increase in proportion to revolving commitment increases), we will be required to maintain as of the end of each fiscal quarter a Fixed Charge Coverage Ratio (as defined in the revolving credit agreement) of at least 1.0 to 1.0.

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If an event of default exists under the revolving credit facility, the lenders will be able to accelerate the maturity of the credit facility and exercise other rights and remedies. An event of default includes, among other things, the nonpayment of principal, interest, fees or other amounts; failure of any representation or warranty to be true and correct when made or confirmed; failure to perform or observe covenants in the revolving credit facility or other loan documents, subject, in limited circumstances, to certain grace periods; cross-defaults in other indebtedness if the effect of such default is to cause, or permit the holders of such indebtedness to cause, the acceleration of such indebtedness under any material agreement; bankruptcy or insolvency events; monetary judgment defaults; asserted invalidity of the loan documentation; and a Change of Control (as defined in the revolving credit agreement).

For additional information regarding our revolving credit facility, see Note 7 of Part I, Item 1 "Financial Statements — Long-Term Debt" in this Quarterly Report.

Long-Term Financing

In addition to our principal sources of short-term liquidity listed above, subject to market conditions, we may meet our cash requirements (other than distributions of Available Cash (as defined in our partnership agreement) to our common unitholders) through the issuance of long-term notes or additional common units.

From time to time we issue long-term debt securities, referred to as our senior notes. All of our outstanding senior notes, other than the 2021 Secured Notes, are unsecured obligations that rank equally with all of our other senior debt obligations to the extent they are unsecured. As of June 30, 2017 and December 31, 2016, we had $400.0 million in 2021 Secured Notes, $900.0 million in 2021 Notes, $350.0 million in 2022 Notes and $325.0 million in 2023 Notes outstanding.

The indentures governing our senior notes contain covenants that, among other things, restrict our ability and the ability of certain of our subsidiaries to: (i) sell assets; (ii) pay distributions on, redeem or repurchase our common units or redeem or repurchase our subordinated debt and, in the case of the 2021 Secured Notes, our unsecured notes; (iii) make investments; (iv) incur or guarantee additional indebtedness or issue preferred units; (v) create or incur certain liens; (vi) enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us; (vii) consolidate, merge or transfer all or substantially all of our assets; (viii) engage in transactions with affiliates and (ix) create unrestricted subsidiaries. These covenants are subject to important exceptions and qualifications. At any time when the senior notes are rated investment grade by either Moody's Investors Service, Inc. ("Moody's") or S&P Global Ratings ("S&P") and no Default or Event of Default, each as defined in the indentures governing the senior notes, has occurred and is continuing, many of these covenants will be suspended. As of June 30, 2017, our Fixed Charge Coverage Ratio (as defined in the indentures governing the 2021 Secured, 2021, 2022 and 2023 Notes) was 1.5 to 1.0.

Upon the occurrence of certain change of control events, each holder of the senior notes will have the right to require that we repurchase all or a portion of such holder's senior notes in cash at a purchase price equal to 101% of the principal amount thereof, plus any accrued and unpaid interest to the date of repurchase.

To date, our debt balances have not adversely affected our operations or our ability to repay or refinance our indebtedness. Based on our historical record, we believe that our capital structure will continue to allow us to achieve our business objectives.

We are subject, however, to conditions in the equity and debt markets for our common units and long-term senior notes, and there can be no assurance we will be able or willing to access the public or private markets for our common units and/or senior notes in the future. If we are unable or unwilling to issue additional common units, we may be required to either restrict capital expenditures and/or potential future acquisitions or pursue debt financing alternatives, some of which could involve higher costs or negatively affect our credit ratings. Furthermore, our ability to access the public and private debt markets is affected by our credit ratings.

For additional information regarding our senior notes, see Note 7 — "Long-Term Debt" under Part I, Item 1 "Financial Statements — Notes to Unaudited Condensed Consolidated Financial Statements" in this Quarterly Report and Note 7 — "Long-Term Debt" in Part II, Item 8 "Financial Statements and Supplementary Data" of our 2016 Annual Report.

Master Derivative Contracts and Collateral Trust Agreement

Under our credit support arrangements, our payment obligations under all of our master derivatives contracts for commodity hedging generally are secured, on a ratable basis with the 2021 Secured Notes, by a first priority lien on our and our subsidiaries' real property, plant and equipment, fixtures, intellectual property, certain financial assets, certain investment property, commercial tort claims, chattel paper, documents, instruments and proceeds of the foregoing (including proceeds of hedge arrangements). We had no additional letters of credit or cash margin posted with any hedging counterparty as of June 30, 2017. Our master derivatives contracts continue to impose a number of covenant limitations on our operating and financing activities, including limitations on liens on collateral, limitations on dispositions of collateral and collateral maintenance and insurance requirements. For financial reporting purposes, we do not offset the collateral provided to a counterparty against the fair value of our obligation to that counterparty. Any outstanding collateral is released to us upon settlement of the related derivative instrument liability.

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All credit support thresholds with our hedging counterparties are at levels such that it would take a substantial increase in fuel products crack spreads or interest rates to require significant additional collateral to be posted. As a result, we do not expect further increases in fuel products crack spreads or interest rates to significantly impact our liquidity. Additionally, we have a collateral trust agreement (the "Collateral Trust Agreement") which governs how the holders of the 2021 Secured Notes and secured hedging counterparties share collateral pledged as security for the payment obligations owed by us to the holders of the 2021 Secured Notes and secured hedging counterparties under their respective master derivatives contracts. The Collateral Trust Agreement limits to $150.0 million the extent to which forward purchase contracts for physical commodities are covered by, and secured under, the Collateral Trust Agreement and the Parity Lien Security Documents (as defined in the Collateral Trust Agreement). There is no such limit on financially settled derivative instruments used for commodity hedging. Subject to certain conditions set forth in the Collateral Trust Agreement, we have the ability to add secured hedging counterparties from time to time.

Contractual Obligations and Commercial Commitments

A summary of our total contractual cash obligations as of June 30, 2017, at current maturities and reflecting only those line items that have materially changed since December 31, 2016, is as follows:

	Payments Due by Period				
	Total	Less Than 1 Year	1–3 Years	3–5 Years	More Than 5 Years
	(In millions)				
Operating activities:					
Interest on long-term debt at contractual rates and maturities [1]	$789.5	$167.6	$328.5	$220.0	$73.4
Operating lease obligations [2]	129.4	37.9	51.8	23.5	16.2
Letters of credit [3]	93.4	93.4	—	—	—
Purchase commitments [4]	1,604.2	634.7	832.7	42.1	94.7
Employment agreements	3.4	2.1	1.0	0.3	—
Financing activities:					
Obligations under inventory financing agreements	106.3	106.3	—	—	—
Capital lease obligations	45.2	2.0	3.6	2.0	37.6
Long-term debt obligations, excluding capital lease obligations	1,982.7	1.4	3.3	1,653.0	325.0
Total obligations	$4,754.1	$1,045.4	$1,220.9	$1,940.9	$546.9

(1) Interest on long-term debt at contractual rates and maturities relates primarily to interest on our senior notes, revolving credit facility interest and fees and interest on our capital lease obligations, which excludes the adjustment for the interest rate swap agreement.

(2) We have various operating leases primarily for railcars, the use of land, storage tanks, compressor stations, equipment, precious metals and office facilities.

(3) Letters of credit primarily supporting crude oil purchases and precious metals leasing.

(4) Purchase commitments consist primarily of obligations to purchase fixed volumes of crude oil, other feedstocks and finished products for resale from various suppliers based on current market prices at the time of delivery.

In connection with the closing of the acquisition of Penreco on January 3, 2008, we entered into a feedstock purchase agreement with Phillips 66 related to the LVT unit at its Lake Charles, Louisiana refinery (the "LVT Feedstock Agreement"). Pursuant to the LVT Feedstock Agreement, Phillips 66 is obligated to supply a minimum quantity (the "Base Volume") of feedstock for the LVT unit for a term of ten years. Based upon the Base Volume, we expect to purchase $34.2 million of feedstock for the LVT unit in each fiscal year of the term based on pricing estimates as of June 30, 2017. This amount is not included in the table above.

For additional information regarding our expected capital and turnaround expenditures for the remainder of 2017, for which we have not contractually committed, refer to "Capital Expenditures" above.

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Off-Balance Sheet Arrangements

We did not enter into any material off-balance sheet debt or operating lease transactions during the three and six months ended June 30, 2017.

Critical Accounting Policies and Estimates

For additional discussion regarding our critical accounting policies and estimates, see “Critical Accounting Policies and Estimates” under Part II, Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations” of our 2016 Annual Report.

Recent Accounting Pronouncements

For additional discussion regarding recent accounting pronouncements, see Note 2 — “New and Recently Adopted Accounting Pronouncements” under Part I, Item 1 “Financial Statements — Notes to Unaudited Condensed Consolidated Financial Statements.”

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

The following should be read in conjunction with "Quantitative and Qualitative Disclosures About Market Risk" included under Part II, Item 7A in our 2016 Annual Report. There have been no material changes in that information other than as discussed below. Also, see Note 8 — "Derivatives" under Part I, Item 1 "Financial Statements — Notes to Unaudited Condensed Consolidated Financial Statements" in this Quarterly Report for additional discussion related to derivative instruments and hedging activities.

Commodity Price Risk

Derivative Instruments

We are exposed to price risks due to fluctuations in the price of crude oil, refined products (primarily in our fuel products segment), natural gas and precious metals. We use various strategies to reduce our exposure to commodity price risk. We do not attempt to eliminate all of our risk as the costs of such actions are believed to be too high in relation to the risk posed to our future cash flows, earnings and liquidity. The strategies we use to reduce our risk utilize both physical forward contracts and financially settled derivative instruments, such as swaps, collars, options and futures, to attempt to reduce our exposure with respect to:

- crude oil purchases and sales;
- refined product sales and purchases;
- natural gas purchases;
- precious metals; and
- fluctuations in the value of crude oil between geographic regions and between the different types of crude oil such as NYMEX WTI, Light Louisiana Sweet ("LLS"), WCS, Mixed Sweet Blend ("MSW") and ICE Brent.

The following table provides a summary of crude oil swap purchases as of June 30, 2017 in our fuel products segment:

Crude Oil Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Swap ($/Bbl)
Third Quarter 2017	327,161	3,556	$ 48.87
Fourth Quarter 2017	327,161	3,556	$ 48.87
Total	654,322		
Average price			$ 48.87

The following table provides a summary of crude oil swap sales as of June 30, 2017 in our fuel products segment:

Crude Oil Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
Third Quarter 2017	133,216	1,448	$ 41.56
Fourth Quarter 2017	133,216	1,448	$ 41.56
Total	266,432		
Average price			$ 41.56

We have entered into crude oil basis swaps to mitigate the risk of future changes in pricing differentials between WCS and NYMEX WTI. The following table provides a summary of crude oil basis swap contracts as of June 30, 2017 in our fuel products segment:

Crude Oil Basis Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Differential to NYMEX WTI ($/Bbl)
Third Quarter 2017	644,000	7,000	$ (13.22)
Fourth Quarter 2017	644,000	7,000	$ (13.22)
Total	1,288,000		
Average differential			$ (13.22)

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We have entered into derivative instruments to secure a percentage differential on WCS crude oil to NYMEX WTI. The following table provides a summary of crude oil percentage basis swap contracts related to crude oil purchases as of June 30, 2017 in our fuel products segment:

Crude Oil Percentage Basis Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Fixed Percentage of NYMEX WTI (Average % of WTI/Bbl)
Third Quarter 2017	276,000	3,000	72.3 %
Fourth Quarter 2017	276,000	3,000	72.3 %
Total	552,000		
Average percentage			72.3 %

The following table provides a summary of natural gas swaps as of June 30, 2017 in our specialty products segment:

Natural Gas Swap Contracts by Expiration Dates	MMBtu	$/MMBtu
Third Quarter 2017	1,320,000	$ 3.87
Fourth Quarter 2017	960,000	$ 3.72
Total	2,280,000	
Average price		$ 3.81

Please read Note 8 — "Derivatives" in the notes to our unaudited condensed consolidated financial statements under Part I, Item 1 "Financial Statements — Notes to Unaudited Condensed Consolidated Financial Statements" for a discussion of the accounting treatment for the various types of derivative instruments and a further discussion of our hedging policies.

Our derivative instruments and overall specialty products segment and fuel products segment hedging positions are monitored regularly by our risk management committee, which includes executive officers. The risk management committee reviews market information and our hedging positions regularly to determine if additional derivatives activity is advised. A summary of derivative positions and a summary of hedging strategy are presented to our general partner's Board of Directors quarterly.

We believe that the fair values of our derivative instruments may diverge materially from the amounts currently recorded at fair value at settlement due to the volatility of commodity prices. Holding all other variables constant, we expect a $1.00 increase in the applicable commodity prices would change our recorded mark-to-market valuation by the following amounts based upon the volumes hedged as of June 30, 2017:

	In millions
Crude oil swaps	$ 0.4
Crude oil basis swaps	$ 1.3
Crude oil percentage basis swaps	$ 0.6
Natural gas swaps	$ 2.3

Compliance Price Risk

Renewable Identification Numbers

We are exposed to market risks related to the volatility in the price of credits needed to comply with governmental programs. The EPA sets annual quotas for the percentage of biofuels that must be blended into transportation fuels consumed in the U.S., and as a producer of motor fuels from petroleum, we are required to blend biofuels into the fuel products we produce at a rate that will meet the EPA's annual quota. To the extent we are unable to blend biofuels at that rate, we must purchase RINs in the open market to satisfy the annual requirement. We have not entered into any derivative instruments to manage this risk, but we have purchased RINs when the price of these instruments is deemed favorable.

Holding other variables constant (RINs requirements), a $1.00 increase in the price of RINs as of June 30, 2017, would be expected to have a negative impact on net income for 2017 of approximately $58.5 million.

Interest Rate Risk

We use various strategies to reduce our exposure to interest rate risk, including the use of financially settled derivative instruments, such as interest rate swaps and options, to minimize significant unplanned fluctuations in earnings that are caused by interest rate volatility. Our goal is to manage interest rate sensitivity by modifying the pricing characteristics of certain debt instruments so that earnings are not adversely affected by movement in interest rates. During 2014, we entered into an interest

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rate swap agreement that converted a portion of our senior notes from a fixed interest rate to a variable rate that fluctuates based on changes in the one-month London Interbank Offered Rate ("LIBOR"). During the first quarter 2015, we terminated this interest rate swap agreement. We have disclosed this interest rate swap designated as a fair value hedge in Note 8 — "Derivatives" under Part I, Item 1 "Financial Statements—Notes to Unaudited Condensed Consolidated Financial Statements."

For the balance of our long-term debt that is not subject to interest rate swap arrangements, our exposure to interest rate changes on this fixed rate debt is limited to the fair value of the debt issued, which would not have a material impact on our earnings or cash flows. The following table provides information about the fair value of our fixed rate debt obligations as of June 30, 2017, and December 31, 2016, which we disclose in Note 7 — "Long-Term Debt" and Note 9 — "Fair Value Measurements" under Part I, Item 1 "Financial Statements — Notes to Unaudited Condensed Consolidated Financial Statements."

	June 30, 2017		December 31, 2016	
	Fair Value	Carrying Value	Fair Value	Carrying Value
	(In millions)			
Financial Instrument:				
2021 Secured Notes	$463.2	$ 386.0	$458.8	$ 384.5
2021 Notes	$783.9	$ 891.4	$763.9	$ 890.2
2022 Notes	$308.7	$ 344.2	$296.0	$ 343.7
2023 Notes	$286.7	$ 318.7	$274.2	$ 318.3

For our variable rate debt, if any, changes in interest rates generally do not impact the fair value of the debt instrument, but may impact our future earnings and cash flows. We had a $900.0 million revolving credit facility as of June 30, 2017, with borrowings bearing interest at the prime rate or LIBOR, at our option, plus the applicable margin. Borrowings under this facility are variable. We had $0.4 million and $10.2 million of variable rate debt as of June 30, 2017, and December 31, 2016, respectively. Holding other variables constant (such as debt levels), a 100 basis point change in interest rates on our variable rate debt as of June 30, 2017, would have an immaterial impact on net income and cash flows for the 2017 period.

Foreign Currency Risk

We have minimal exposure to foreign currency risk and as such the cost of hedging this risk is viewed to be in excess of the benefit of further reductions in our exposure to foreign currency exchange rate fluctuations.

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Item 4. Controls and Procedures

(a) Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) of the Securities Exchange Act of 1934, as amended (the “Exchange Act”), we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Quarterly Report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of June 30, 2017, at the reasonable assurance level.

(b) Changes in Internal Control over Financial Reporting

There was no change in our internal control over financial reporting during the second quarter 2017 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART II

Item 1. Legal Proceedings

We are not a party to, and our property is not the subject of, any pending legal proceedings other than ordinary routine litigation incidental to our business. Our operations are subject to a variety of risks and disputes normally incidental to our business. As a result, we may, at any given time, be a defendant in various legal proceedings and litigation arising in the ordinary course of business. The information provided under Note 5 — "Commitments and Contingencies" in Part I, Item 1 "Financial Statements — Notes to Unaudited Condensed Consolidated Financial Statements" is incorporated herein by reference.

Item 1A. Risk Factors

In addition to the other information set forth in this Quarterly Report, you should carefully consider the risks discussed in Part I, Item 1A "Risk Factors" in our 2016 Annual Report. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition or future results. There have been no material changes in the risk factors discussed in Part I, Item 1A "Risk Factors" in our 2016 Annual Report or in Part II, Item 1A "Risk Factors" in our Q1 Quarterly Report other than with respect to the risk factors discussed below.

Our Supply and Offtake Agreements with Macquarie include provisions for early termination and could represent a refinancing risk.

When we executed the Supply and Offtake Agreements, the inventories associated with such agreements were taken out of our revolving credit facility borrowing base. As such, these inventories are not part of our revolving credit facility. Should Macquarie choose to exercise its option to terminate the Supply and Offtake Agreements by giving nine months notice of such termination, we would need to seek alternative sources of financing, including putting the inventory back into our revolving credit facility, to meet our obligation to repurchase the inventory at then current market prices. Should we be unable to include the inventory in our borrowing base, we could suffer significant reductions in liquidity when Macquarie terminates the Supply and Offtake Agreements and we have to repurchase the inventories.

Our arrangement with Macquarie exposes us to Macquarie-related credit and performance risk.

We have Supply and Offtake Agreements with Macquarie, pursuant to which Macquarie will intermediate crude oil supplies and refined product inventories at our Great Falls and Shreveport refineries. Macquarie will own all of the crude oil in our tanks and substantially all of our refined product inventories prior to our sale of the inventories. Upon termination of the Supply and Offtake Agreements, which may be terminated by Macquarie as early as October 2017 for the Great Falls inventory, we are obligated in certain scenarios to repurchase all crude oil and refined product inventories then owned by Macquarie and located at the specified storage facilities at then current market prices. Relying on Macquarie's ability to honor its supply and offtake obligations exposes us to Macquarie's credit and business risks. An adverse change in Macquarie's business, results of operations, liquidity or financial condition could adversely affect its ability to perform its obligations, which could consequently have a material adverse effect on our business, results of operations or liquidity and, as a result, our business and operating results. In addition, we may be required to use substantial capital to repurchase crude oil and refined product inventories from Macquarie upon termination of the agreements, which could have a material adverse effect on our business, results of operations or financial condition.

Inadequate liquidity could materially and adversely affect our business operations in the future.

If our cash flow and capital resources are insufficient to fund our obligations, we may be forced to reduce our capital expenditures, seek additional equity or debt capital or restructure our indebtedness. We cannot assure you that any of these remedies could, if necessary, be affected on commercially reasonable terms, or at all. Our liquidity is constrained by our need to satisfy our obligations under our credit agreements and our Supply and Offtake Agreements. The availability of capital when the need arises will depend upon a number of factors, some of which are beyond our control. These factors include general economic and financial market conditions, the crack spread, natural gas and crude oil prices, our credit ratings, interest rates, market perceptions of us or the industries in which we operate, our market value and our operating performance. We may be unable to execute our long-term operating strategy if we cannot obtain capital from these or other sources when the need arises.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

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Item 5. Other Information

None.

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Item 6. Exhibits

The following documents are filed as exhibits to this Quarterly Report:

Exhibit Number	Description
3.1	Certificate of Limited Partnership of Calumet Specialty Products Partners, L.P. (incorporated by reference to Exhibit 3.1 to the Registrant's Registration Statement on Form S-1 filed with the Commission on October 7, 2005 (File No. 333-128880)).
3.2	Amended and Restated Limited Partnership Agreement of Calumet Specialty Products Partners, L.P. (incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the Commission on February 13, 2006 (File No. 000-51734)).
3.3	Amendment No. 1 to the First Amended and Restated Agreement of Limited Partnership of Calumet Specialty Products Partners, L.P. (incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the Commission on July 11, 2006 (File No. 000-51734)).
3.4	Amendment No. 2 to First Amended and Restated Agreement of Limited Partnership of Calumet Specialty Products Partners, L.P. (incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the Commission on April 18, 2008 (File No. 000-51734)).
3.5	Certificate of Formation of Calumet GP, LLC (incorporated by reference to Exhibit 3.3 of Registrant's Registration Statement on Form S-1 filed with the Commission on October 7, 2005 (File No. 333-128880)).
3.6	Amended and Restated Limited Liability Company Agreement of Calumet GP, LLC (incorporated by reference to Exhibit 3.2 to the Registrant's Current Report on Form 8-K filed with the Commission on February 13, 2006 (File No. 000-51734)).
10.1*	Employment and Transition Agreement, dated as of April 17, 2017, by and among the Company and R. Patrick Murray, II.
10.2*	Supply and Offtake Agreement, dated as of June 19, 2017, between Macquarie Energy North America Trading Inc., Calumet Shreveport Fuels, LLC and Calumet Shreveport Lubricants & Waxes, LLC
10.3*†	Calumet GP, LLC Annual Bonus Plan, dated February 23, 2017 and effective January 1, 2017.
10.4*†	Form of Award Agreement (included as an attachment to Exhibit 10.3).
31.1*	Sarbanes-Oxley Section 302 certification of Timothy Go.
31.2*	Sarbanes-Oxley Section 302 certification of D. West Griffin.
32.1**	Section 1350 certification of Timothy Go and D. West Griffin.
100.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document

101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

*	Filed herewith.
**	Furnished herewith.
†	Identifies management contract and compensatory plan arrangements.

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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.

		CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.	
		By:	Calumet GP, LLC, its general partner
Date:	August 7, 2017	By:	/s/ D. West Griffin D. West Griffin Executive Vice President and Chief Financial Officer of Calumet GP, LLC (Principal Accounting and Financial Officer) (Authorized Person and Principal Accounting Officer)

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