Calumet Specialty Products Partners, L.P.
Form 10-Q
August 05, 2016
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2016
OR
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM TO
Commission File Number: 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 x 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 x No ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

Large accelerated filer x	Accelerated filer ¨

Non-accelerated filer o (Do not check if a smaller reporting company) Smaller reporting company ¨
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x
On August 5, 2016, there were 76,371,419 common units outstanding.

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CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
QUARTERLY REPORT
For the Three and Six Months Ended June 30, 2016
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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" 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 acquisitions. 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, 2015 ("2015 Annual Report"), (ii) Part II, Item 1A "Risk Factors" in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2016 ("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, 2016 (Unaudited)	December 31, 2015
	(In millions, except unit data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$32.2	$ 5.6
Accounts receivable:		
Trade	242.6	195.3
Other	27.6	15.4
	270.2	210.7
Inventories	444.9	384.4
Derivative assets	4.9	—
Prepaid expenses and other current assets	11.5	8.3
Total current assets	763.7	609.0
Property, plant and equipment, net	1,705.0	1,719.2
Investment in unconsolidated affiliates	6.9	126.0
Goodwill	178.6	212.0
Other intangible assets, net	197.2	214.1
Other noncurrent assets, net	55.4	64.4
Total assets	$2,906.8	$ 2,944.7
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$316.2	$ 316.6
Accrued interest payable	40.2	31.1
Accrued salaries, wages and benefits	13.3	32.9
Other taxes payable	21.1	17.9
Other current liabilities	144.7	119.0
Current portion of long-term debt	1.6	1.7
Note payable — related party	39.9	73.5
Derivative liabilities	10.4	33.9
Total current liabilities	587.4	626.6
Noncurrent deferred income taxes	2.0	2.1
Pension and postretirement benefit obligations	12.0	13.0
Other long-term liabilities	1.0	0.9
Long-term debt, less current portion	1,972.9	1,698.2
Total liabilities	2,575.3	2,340.8
Commitments and contingencies		
Partners' capital:		
Limited partners' interest 76,346,289 units and 75,884,400 units, issued and outstanding as of June 30, 2016, and December 31, 2015, respectively	319.3	578.0
General partner's interest	18.1	27.5
Accumulated other comprehensive loss	(5.9)	(1.6)

Total partners’ capital	331.5	603.9
Total liabilities and partners’ capital	$2,906.8	$ 2,944.7

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,	
	2016	2015	2016	2015
	(In millions, except per unit and unit data)			
Sales	$972.9	$1,156.2	$1,685.9	$2,174.8
Cost of sales	841.6	953.5	1,468.4	1,776.9
Gross profit	131.3	202.7	217.5	397.9
Operating costs and expenses:				
Selling	26.2	37.8	56.7	76.2
General and administrative	24.8	31.7	52.4	70.9
Transportation	45.0	42.3	84.2	84.3
Taxes other than income taxes	4.2	4.0	9.9	8.0
Asset impairment	33.4	—	33.4	—
Other	0.3	3.2	2.3	6.1
Operating income (loss)	(2.6)	83.7	(21.4)	152.4
Other income (expense):				
Interest expense	(42.8)	(27.4)	(73.1)	(54.4)
Debt extinguishment costs	—	(46.6)	—	(46.6)
Realized loss on derivative instruments	(6.0)	(14.0)	(18.3)	(5.1)
Unrealized gain (loss) on derivative instruments	23.8	5.2	28.4	(22.7)
Loss from unconsolidated affiliates	(7.1)	(8.2)	(18.2)	(12.7)
Loss on sale of unconsolidated affiliates	(113.4)	—	(113.4)	—
Other	0.5	0.7	0.9	1.5
Total other expense	(145.0)	(90.3)	(193.7)	(140.0)
Net income (loss) before income taxes	(147.6)	(6.6)	(215.1)	12.4
Income tax expense (benefit)	0.3	(9.1)	0.5	(13.9)
Net income (loss)	$(147.9)	$2.5	$(215.6)	$26.3
Allocation of net income (loss):				
Net income (loss)	$(147.9)	$2.5	$(215.6)	$26.3
Less:				
General partner's interest in net income (loss)	(2.9)	—	(4.3)	0.5
General partner's incentive distribution rights	—	4.2	—	8.4
Net income (loss) available to limited partners	$(145.0)	$(1.7)	$(211.3)	$17.4
Weighted average limited partner units outstanding:				
Basic	76,761,504	76,092,517	76,491,775	73,675,251
Diluted	76,761,504	76,092,517	76,491,775	73,730,189
Limited partners' interest basic and diluted net income (loss) per unit	$(1.89)	$(0.02)	$(2.76)	$0.23
Cash distributions declared per limited partner unit	$—	$0.685	$0.685	$1.37

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,	
	2016	2015	2016	2015
	(In millions)			
Net income (loss)	$(147.9)	$2.5	$(215.6)	$26.3
Other comprehensive income (loss):				
Cash flow hedges:				
Cash flow hedge gain reclassified to net income (loss)	(2.3)	(11.5)	(4.4)	(9.8)
Change in fair value of cash flow hedges	—	(1.1)	—	(6.2)
Defined benefit pension and retiree health benefit plans	0.1	0.1	0.1	0.3
Foreign currency translation adjustment	—	—	—	(0.3)
Total other comprehensive loss	(2.2)	(12.5)	(4.3)	(16.0)
Comprehensive income (loss) attributable to partners’ capital	$(150.1)	$(10.0)	$(219.9)	$10.3

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	Limited Partners	Total
	(In millions)			
Balance at December 31, 2015	$(1.6)	$27.5	$578.0	$603.9
Other comprehensive loss	(4.3)	—	—	(4.3)
Net loss	—	(4.3)	(211.3)	(215.6)
Amortization of vested phantom units	—	—	2.9	2.9
Issuances of phantom units	—	—	4.1	4.1
Settlement of tax withholdings on equity-based incentive compensation	—	—	(2.3)	(2.3)
Contributions from Calumet GP, LLC	—	0.2	—	0.2
Distributions to partners	—	(5.3)	(52.1)	(57.4)
Balance at June 30, 2016	$(5.9)	$18.1	$319.3	$331.5

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,	
	2016	2015
	(In millions)	
Operating activities		
Net income (loss)	$(215.6)	$26.3
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Depreciation and amortization	82.6	71.4
Amortization of turnaround costs	17.4	12.7
Non-cash interest expense	4.6	2.9
Non-cash debt extinguishment costs	—	9.1
Provision for doubtful accounts	0.5	0.2
Unrealized (gain) loss on derivative instruments	(28.4)	22.7
Asset impairment	33.4	—
(Gain) loss on disposal of fixed assets	(0.7)	1.0
Non-cash equity based compensation	2.9	5.5
Deferred income tax benefit	(0.2)	(14.1)
Lower of cost or market inventory adjustment	(44.4)	0.8
Loss from unconsolidated affiliates	18.2	12.7
Loss on sale of unconsolidated affiliates	113.4	—
Other non-cash activities	2.3	2.9
Changes in assets and liabilities:		
Accounts receivable	(60.0)	39.4
Inventories	(10.3)	(40.6)
Prepaid expenses and other current assets	(1.5)	4.5
Derivative activity	(10.4)	(3.5)
Turnaround costs	(8.1)	(5.9)
Other assets	(0.4)	—
Accounts payable	35.1	(7.0)
Accrued interest payable	9.1	(5.1)
Accrued salaries, wages and benefits	(16.0)	1.6
Other taxes payable	3.2	1.3
Other liabilities	22.5	21.7
Pension and postretirement benefit obligations	(0.9)	(0.5)
Net cash provided by (used in) operating activities	(51.7)	160.0
Investing activities		
Additions to property, plant and equipment	(87.9)	(153.2)
Investment in unconsolidated affiliates	(41.8)	(46.0)
Proceeds from sale of unconsolidated affiliates	29.0	—
Proceeds from sale of property, plant and equipment	1.9	0.2
Net cash used in investing activities	(98.8)	(199.0)
Financing activities		
Proceeds from borrowings — revolving credit facility	479.0	637.3
Repayments of borrowings — revolving credit facility	(589.9)	(685.0)
Repayments of borrowings — senior notes	—	(275.0)
Repayments of borrowings — related party note	(34.5)	—

Payments on capital lease obligations	(4.1)	(3.5)
Proceeds from other financing obligations	2.4	—
Proceeds from senior notes offering	393.1	322.6
Debt issuance costs	(9.9)	(5.6)
Proceeds from public offerings of common units, net	—	161.5
Contributions from Calumet GP, LLC	0.2	3.5
Common units repurchased and taxes paid for phantom unit grants	(1.8)	(3.6)
Distributions to partners	(57.4)	(110.0)
Net cash provided by financing activities	177.1	42.2
Net increase in cash and cash equivalents	26.6	3.2
Cash and cash equivalents at beginning of period	5.6	8.5
Cash and cash equivalents at end of period	$32.2	$11.7
Supplemental disclosure of non-cash financing and investing activities		
Non-cash property, plant and equipment additions	$20.5	$61.9

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, 2016, the Company had 76,346,289 limited partner common units and 1,558,087 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, 2016, and for the three and six months ended June 30, 2016 and 2015, 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. 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, 2016, are not necessarily indicative of the results that may be expected for the year ending December 31, 2016. These unaudited condensed consolidated financial statements should be read in conjunction with the Company's 2015 Annual Report.
2. Summary of Significant Accounting Policies
Reclassifications
Certain amounts in the prior years' condensed consolidated financial statements have been reclassified to conform to the current year presentation.
Other Current Liabilities
Other current liabilities consisted of the following at June 30, 2016 and December 31, 2015 (in millions):

	June 30, 2016	December 31, 2015
RINs Obligation	$ 114.7	$ 88.4
Other	30.0	30.6
Total	$ 144.7	$ 119.0

The Company's RINs obligation ("RINs Obligation") represents a liability for the purchase of RINs to satisfy the U.S. 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. 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. Excess RINs are classified as inventory in the condensed consolidated balance sheets. The

Company recognizes a liability at the end of each reporting period in which the Company does not have sufficient RINs to cover the RINs Obligation. The liability is calculated by multiplying the RINs shortage (based on actual results) by the period end RIN spot price.

From time to time, the Company holds varying amounts of RINs for resale. RINs obtained from third parties are initially recorded at their cost at the time the Company acquires them and are subsequently revalued at the lower of cost or market as of the last day of each accounting period and the resulting adjustments are reflected in costs of goods sold for the period. The value of RINs obtained from third parties would be reflected in prepaid expenses and other assets on the consolidated balance sheets.

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New Accounting Pronouncements

In March 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-09, Compensation — Stock Compensation (Topic 606): Improvements to Employee Share-Based Payment Accounting ("ASU 2016-09"). ASU 2016-09 involves several aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities and classification on the statement of cash flows. Under the new standard, income tax benefits and deficiencies are to be recognized as income tax expense or benefit in the income statement and the tax effects of exercised or vested awards should be treated as discrete items in the reporting period in which they occur. Excess tax benefits should be classified along with other income tax cash flows as an operating activity. In regards to forfeitures, the entity may make an entity-wide accounting policy election to either estimate the number of awards that are expected to vest or account for forfeitures when they occur. The amendments in this standard are effective for fiscal years (including interim periods) beginning after December 15, 2016, with early adoption permitted. The adoption of ASU 2016-09 is not expected to have an impact on the Company's condensed consolidated financial statements.

In March 2016, the FASB issued ASU No. 2016-07, Investments — Equity Method and Joint Ventures (Topic 323): Simplifying the Transition to the Equity Method of Accounting ("ASU 2016-07"), which eliminates the retroactive adjustments to an investment upon it qualifying for the equity method of accounting as a result of an increase in the level of ownership interest or degree of influence by the investor. ASU 2016-07 requires that the equity method investor add the cost of acquiring the additional interest in the investee to the current basis of the investor's previously held interest and adopt the equity method of accounting as of the date the investment qualifies for equity method accounting. The amendments in this standard are effective for fiscal years (including interim periods) beginning after December 15, 2016, with early adoption permitted. The adoption of ASU 2016-07 is not expected to have an impact on the Company's condensed consolidated financial statements.

In March 2016, the FASB issued ASU No. 2016-06, Derivatives and Hedging (Topic 815): Contingent Put and Call Options in Debt Instruments ("ASU 2016-06"). ASU 2016-06 simplifies the embedded derivative analysis for debt instruments containing contingent call or put options by removing the requirement to assess whether a contingent event is related to interest rates or credit risks. The amendments in this standard are effective for fiscal years (including interim periods) beginning after December 15, 2016, with early adoption permitted. The adoption of ASU 2016-06 is not expected to have an impact on the Company's condensed consolidated financial statements.

In March 2016, the FASB issued ASU No. 2016-05, Derivatives and Hedging (Topic 815): Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships ("ASU 2016-05"). ASU 2016-05 clarifies that a change in the counterparty to a derivative instrument that has been designated as a hedging instrument under Topic 815 does not, in and of itself, require dedesignation of that hedging relationship provided that all other hedge accounting criteria continue to be met. The amendments in this standard are effective for fiscal years (including interim periods) beginning after December 15, 2016, with early adoption permitted. An entity can elect to adopt the amendments of ASU 2016-05 on either a prospective or modified retrospective basis. The adoption of ASU 2016-05 is not expected to have an impact on the Company's 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 condensed 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 effective for fiscal years (including interim periods) beginning after December 15, 2017, with early adoption not permitted. The Company is currently evaluating the impact of this standard on its 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 ASC 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

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consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 also requires additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts, including significant judgments and changes in judgments and assets recognized from costs incurred to obtain or fulfill a contract. ASU 2014-09 was originally effective for fiscal years (including interim periods) beginning after December 15, 2016. 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 effective date by one year, 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 2016, the FASB issued ASU No. 2016-08, Revenue from Contracts with Customers (Topic 606) — Principal versus Agent Considerations ("ASU 2016-08"). ASU 2016-08 provides clarifying guidance regarding the application of ASU 2014-09 when another party, along with the reporting entity, is involved in providing a good or a service to a customer. In these circumstances, an entity is required to determine whether the nature of its promise is to provide that good or service to the customer (that is, the entity is a principal) or to arrange for the good or service to be provided to the customer by the other party (that is, the entity is an agent). ASU 2016-08 clarifies the implementation guidance on principal versus agent considerations. In April 2016, the FASB issued ASU No. 2016-10, Revenue from Contracts with Customers (Topic 606) — Identifying Performance Obligations and Licensing ("ASU 2016-10"). ASU 2016-10 further amends the guidance with respect to certain implementation issues on identifying performance obligations and accounting for licenses of intellectual property. In May 2016, the FASB issued ASU No. 2016-11, Revenue Recognition (Topic 605) and Derivatives and Hedging (Topic 815) — Rescission of SEC Guidance Because of Accounting Standards Updates 2014-09 and 2014-16 Pursuant to Staff Announcements at the March 3, 2016, EITF Meeting ("ASU 2016-11"). The amendments in ASU 2016-11 rescinded certain SEC Staff Observer comments that are codified, effective upon the adoption of ASU 2014-09. In May 2016, the FASB issued ASU No. 2016-12, Revenue from Contracts with Customers (Topic 606) — Narrow-Scope Improvements and Practical Expedients ("ASU 2016-12"). The amendments in ASU 2016-12 address certain issues identified in the guidance on assessing collectibility, presentation of sales taxes, non-cash consideration and completed contracts and contract modifications at transition. Companies are permitted to either apply the requirements retrospectively to all prior periods presented or apply the requirements in the year of adoption through a cumulative adjustment. The amendments in these standards, along with ASU 2014-09, are effective for fiscal years (including interim periods) beginning after December 15, 2017. The Company is currently evaluating the impact of these standards on its condensed consolidated financial statements.

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 $62.5 million and $41.0 million lower as of June 30, 2016, and December 31, 2015, respectively.

Inventories consist of the following (in millions):

	June 30, 2016	December 31, 2015
Raw materials	$ 64.2	$ 47.9
Work in process	76.1	64.0
Finished goods	304.6	272.5
	$ 444.9	$ 384.4

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 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, 2016 and 2015, the Company recorded $36.3 million and $12.4 million of gains, respectively, in cost of sales in the condensed consolidated statements of operations due to the lower of cost or market ("LCM") valuation. During the six months ended June 30, 2016 and 2015, the Company recorded $44.4 million of gains and $0.8 million of losses, respectively, in cost of sales in the condensed consolidated statements of operations due to the LCM valuation.

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4. Investment in Unconsolidated Affiliates

The following table summarizes the Company's investments in unconsolidated affiliates as of June 30, 2016, and December 31, 2015 (in millions):

	June 30, 2016		December 31, 2015	
	Investment	Percent Ownership	Investment	Percent Ownership
Dakota Prairie Refining, LLC	$—	— %	$124.7	50.0 %
Pacific New Investment Limited	5.9	13.8 %	—	— %
Other	1.0		1.3	
Total	$6.9		$126.0	

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 three and six months ended June 30, 2016.

The following represents summary financial information for Dakota Prairie, presented at 100% (in millions):

	Three Months Ended June 27, 2016	Three Months Ended June 30, 2015	Six Months Ended June 27, 2016	Six Months Ended June 30, 2015
Operating revenue	$74.3	$48.4	$119.4	$50.1
Operating loss	$(12.7)	$(14.8)	$(33.5)	$(21.8)
Net loss	$(13.6)	$(15.2)	$(35.2)	$(22.3)

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 expects to invest $10.0 million in cash and provide a technology license in exchange for an equity interest of approximately 10% in Hi-Speed through its ownership of 23.8% in PACNIL.

The Company accounts for its ownership in PACNIL under the equity method of accounting. As of June 30, 2016, the Company had an investment of $5.9 million in PACNIL, primarily related to the purchase of equity in the Hi-Speed joint venture.

5. Goodwill

In April 2016, Calumet GP, LLC's Board of Directors determined to suspend payment of the Company's quarterly cash distribution. The suspension of the quarterly cash distribution caused a sustained decrease in the Company's common unit price. As a result, the Company determined that these recent events constituted a triggering event that required the Company to update its financial projections and its goodwill impairment assessment as of April 30, 2016. An impairment charge of $33.4 million for goodwill related to the fuels segment has been recorded in the unaudited condensed consolidated statements of operations within asset impairment. The impairment charge was primarily driven by the reduced outlook on revenues and profitability as a result of falling crude oil prices and crack spreads.

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To derive the fair value of the reporting units, as required in step one of the impairment test, the Company used the income approach, specifically the discounted cash flow method, to determine the fair value of each reporting unit and the associated amount of the impairment charge. 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.

Inputs used to estimate the fair value of the Company's reporting units are considered Level 3 inputs of the fair value hierarchy and include the following:

- The Company's financial projections for its reporting units are based on its analysis of various supply and demand factors which include, among other things, industry-wide capacity, its planned utilization rate, end-user demand, crack spreads, capital expenditures and economic conditions. Such estimates are consistent with those used in the Company's planning and capital investment reviews and include recent historical prices and published forward prices. Revenue growth rates assumed for the Company's Great Falls reporting unit where impairment was recognized were approximately 41.1% for 2016 and (2.6)% to 39.9% for 2017 and beyond. Revenue growth rates assumed for the Company's San Antonio reporting unit where impairment was recognized were approximately (8.5)% for 2016 and (1.0)% to 27.4%, respectively, for 2017 and beyond.

- The discount rate used to measure the present value of the projected future cash flows is based on a variety of factors, including market and economic conditions, operational risk, regulatory risk and political risk. This discount rate is also compared to recent observable market transactions, if possible. The discount rate used for the Company's Great Falls and San Antonio reporting units where impairment was recognized were approximately 13.0% and 13.5%, respectively, per year.

For Level 3 measurements, significant increases or decreases in long-term growth rates or discount rates in isolation or in combination could result in a significantly lower or higher fair value measurement.

Changes in goodwill balances for the periods indicated below are as follows (in millions):

	Specialty Products	Fuel Products	Oilfield Services	Total
Net balance as of December 31, 2014	$ 173.5	$ 38.5	$ 33.8	$ 245.8
Impairment [(1)]	—	—	(33.8)	(33.8)
Net balance as of December 31, 2015	$ 173.5	$ 38.5	$ —	$ 212.0
Impairment [(1)]	—	(33.4)	—	(33.4)
Net balance as of June 30, 2016	$ 173.5	$ 5.1	$ —	$ 178.6

(1) Total accumulated goodwill impairment as of June 30, 2016, and December 31, 2015, is $103.2 million and $69.8 million, respectively.

6. 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, which activities are subject to stringent federal, state, regional and local laws and regulations 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

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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 remedied 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 expenses totaled approximately $18.5 million as of June 30, 2016, of which $14.6 million was capitalized into the cost of the Company's recently completed expansion project and $3.9 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 granted Holly's motion to dismiss the case and ordered that all of the claims be addressed in arbitration. In the event the Company is unsuccessful, the Company will be responsible for the remediation expenses. The Company expects that it may incur some costs to remediate other environmental conditions at the Great Falls refinery; however, 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, 2016, the Company estimates costs of up to $4.0 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, 2016 and 2015, the Company incurred less than $0.1 million for costs related to installing process equipment at the Superior refinery pursuant to EPA fuel content regulations.

On June 29, 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 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 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, Cotton Valley and Princeton refineries on an agreed-upon schedule. During the three months ended June 30, 2016, the Company incurred no such expenditures. During the three months ended June 30, 2015, the Company incurred approximately $1.4 million of such expenditures. During the six months ended June 30, 2016 and 2015, the Company incurred approximately $0.4 million and $2.4 million, respectively, of such expenditures and estimates additional expenditures of approximately $3.0 million to $5.0 million of capital expenditures and expenditures related to additional personnel and environmental studies through 2016 as a result of the implementation of these requirements. These capital investment requirements are incorporated into the Company's annual capital expenditures budget and the Company does not expect any additional capital expenditures as a result of the required audits or required operational changes 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.

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, 2016, the trust fund contained approximately $0.8 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.

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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

The Company's 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 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 net of amounts internally generated or purchased and the price of those RINs as of the balance sheet date.

On June 28, 2016, the EPA granted certain of the Company's refineries a "small refinery exemption" under the RFS for the full year 2014, as provided for under the Clean Air Act. In granting those exemptions, the EPA determined that for the full year 2014, compliance with the RFS would represent a "disproportionate economic hardship" for these refineries.

As of June 30, 2016, the Company had a RINs Obligation of $114.7 million. RINs expense for the three and six months ended June 30, 2016, was $8.2 million and $25.0 million, respectively. As of June 30, 2015, the Company had a RINs Obligation of $41.5 million. RINs gain for the three and six months ended June 30, 2015, was $9.6 million and $2.3 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 ensure 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.

The Company has completed studies to assess the adequacy of its PSM practices at its Shreveport refinery with respect to certain consensus codes and standards. During the three months ended June 30, 2016, the Company incurred no PSM related capital expenditures. During the three months ended June 30, 2015, the Company incurred $0.2 million of PSM related capital expenditures. During the six months ended June 30, 2016 and 2015, the Company incurred $0.3 million and $0.3 million, respectively, of related capital expenditures and expects to incur up to an additional $1.0 million during 2016 to address OSHA compliance issues identified in these studies. The Company expects these capital expenditures will enhance its equipment such that the equipment maintains compliance with applicable consensus codes and standards.

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.

Labor Matters

The Company has employees covered by various collective bargaining agreements. The Company's Cotton Valley facility collective bargaining agreement was ratified on April 1, 2016, and will expire on March 31, 2019. The Dickinson facility collective bargaining agreement was ratified on April 1, 2016, and will expire on March 31, 2019.

The Missouri esters facility collective bargaining agreement was ratified on May 1, 2016, and will expire on April 30, 2017. The Shreveport refinery collective bargaining agreement was extended on May 1, 2016, until a new agreement is reached or is voided by either party with a 30-day written notice.

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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 condensed consolidated financial statements but are not, individually or in the aggregate, 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, 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.

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, 2016 and December 31, 2015, the Company had outstanding standby letters of credit of $64.4 million and $66.8 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, 2016 and December 31, 2015, 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 ($1.0 billion at June 30, 2016, and December 31, 2015) with the consent of the Agent (as defined below).

As of June 30, 2016 and December 31, 2015, the Company had availability to issue letters of credit of $437.5 million and $233.5 million, respectively, under its revolving credit facility.

7. Long-Term Debt

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

	June 30, 2016	December 31, 2015
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 3.7% at June 30, 2016	$0.1	$ 111.0
Borrowings under 2021 Secured Notes, interest at a fixed rate of 11.50%, interest payments semiannually, borrowings due January 2021, effective interest rate of 12.1% for the six months ended June 30, 2016	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, 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, 2016 (1)	352.7	352.9
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, 2016	325.0	325.0
Related party note payable, interest at a fixed rate of 6.0% on a portion of the note, interest payments at various dates, borrowings due July 2016, weighted average interest rate of 6.0% for the six months ended June 30, 2016	39.9	73.5
Capital lease obligations, at various interest rates, interest and principal payments monthly through October 2034	45.6	46.4
Less unamortized debt issuance costs (2)	(36.0)	(28.9)
Less unamortized discounts	(12.9)	(6.5)
Total long-term debt	2,014.4	1,773.4

Less current portion of note payable — related party	39.9	73.5
Less current portion of long-term debt	1.6	1.7
	$1,972.9	$ 1,698.2

(1) The balance includes a fair value interest rate hedge adjustment, which increased the debt balance by $2.7 million and $2.9 million as of June 30, 2016, and December 31, 2015, 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 $10.9 million and $8.1 million at June 30, 2016, and December 31, 2015, 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 $383.2 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.

At any time prior to April 15, 2018, the Company may on any one or more occasions redeem up to 35% of the aggregate principal amount of the 2021 Secured Notes with the net proceeds of a public or private equity offering at a redemption price of 111.5% of the principal amount, plus any accrued and unpaid interest to the date of redemption, provided that: (1) at least 65% of the aggregate principal amount of 2021 Secured Notes issued remains outstanding immediately after the occurrence of such redemption and (2) the redemption occurs within 180 days of the date of the closing of such public or private equity offering.

On and after April 15, 2018, the Company may on any one or more occasions redeem all or a part of the 2021 Secured Notes at the redemption prices (expressed as percentages of principal amount) set forth below, plus any accrued and unpaid interest to the applicable redemption date on such 2021 Secured Notes, if redeemed during the twelve-month period beginning on April 15 of the years indicated below:

Year	Percentage
2018	111.500 %
2019	108.625 %
2020 and thereafter	100.000 %

Prior to April 15, 2018, the Company may on any one or more occasions redeem all or part of the 2021 Secured Notes at a redemption price equal to the sum of: (1) the principal amount thereof, plus (2) a make-whole premium (as set forth in the indenture governing the 2021 Secured Notes) at the redemption date, plus any accrued and unpaid interest to the applicable redemption date.

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.

On March 27, 2015, in connection with the issuance and sale of the 2023 Notes, the Company entered into a registration rights agreement with the initial purchasers of the 2023 Notes obligating the Company to use reasonable best efforts to file an exchange offer registration statement with the SEC, so that holders of the 2023 Notes can offer to exchange the 2023 Notes for registered notes having substantially the same terms as the 2023 Notes and evidencing the same indebtedness as the 2023 Notes. On December 11, 2015, the Company filed an exchange offer registration statement for the 2023 Notes with the SEC, which was declared effective on January 28, 2016. The exchange offer was completed on March 7, 2016, thereby fulfilling all of the requirements of the 2023 Notes registration rights agreement.

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 (the “2019 Notes”) 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.
2021 Secured Notes, 2021 Notes, 2022 Notes and 2023 Notes
In accordance with SEC Rule 3-10 of Regulation S-X, 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, 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, 2016, the Company’s Fixed Charge Coverage Ratio (as defined in the indentures governing the 2021

Secured, 2021, 2022 and 2023 Notes) was 0.8 to 1.0. As of June 30, 2016, 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 $1.0 billion 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, 2016, the margin was 75 basis points for prime rate loans and

175 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 during the preceding fiscal quarter.

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, 2016, under the revolving credit facility was $502.0 million. As of June 30, 2016, the Company had $0.1 million in outstanding borrowings under the revolving credit facility and outstanding standby letters of credit of $64.4 million, leaving $437.5 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, inventory and substantially all of its cash (collectively, the "Credit Agreement Collateral").

On April 20, 2016, the Company and certain of its operating subsidiaries as borrowers (collectively, the "Borrowers") entered into a Second Amendment to Second Amended and Restated Credit Agreement (the "Second Amendment"), by and among the Borrowers, the Agent (as defined below) and the lenders party thereto (including Bank of America, N.A.), amending the Company's revolving credit facility. The Second Amendment, among other things, amends the revolving credit facility to permit (a) the issuance of the 2021 Secured Notes pursuant to the indenture governing the 2021 Secured Notes and (b) such 2021 Secured Notes to be secured by a lien on the Fixed Asset Collateral (as defined in the Intercreditor Agreement), subject to the terms of the Intercreditor Agreement.

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 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, 2016, the Company was in compliance with all covenants under the revolving credit facility.

Collateral Trust Agreement

In connection with the private placement of the 2021 Secured Notes, on April 20, 2016, the Company entered into 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 it 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, the Company has the ability to add secured hedging counterparties from time to time.

Intercreditor Agreement

The 2021 Secured Notes are not secured by the collateral securing the Company's revolving credit facility. In connection with the offering of the 2021 Secured Notes, the Collateral Trustee entered into a Second Amended and Restated Intercreditor Agreement (the "Intercreditor Agreement") among the Collateral Trustee, as fixed asset collateral trustee, Bank of America, N.A., as agent for the lenders under the Company's revolving credit facility (in such capacity, the "Agent"), the Company and the other grantors named therein, providing for certain access and administrative agreements with respect to the Credit Agreement Collateral and the Fixed Asset Collateral (as defined in the Intercreditor Agreement).

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Maturities of Long-Term Debt

As of June 30, 2016, principal payments on debt obligations and future minimum rentals on capital lease obligations are as follows (in millions):

Year	Maturity
2016	$41.5
2017	1.6
2018	1.5
2019	1.4
2020	0.9
Thereafter	2,014.5
Total	$2,061.4

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 ("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 ensure 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 in 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 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 Company's financial results are subject to the possibility that changes in a derivative's fair value could result in significant ineffectiveness and potentially no longer qualify portions or all of its derivative instruments for hedge accounting.

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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, 2016, and December 31, 2015 (in millions):

	June 30, 2016			December 31, 2015		
	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	$—	$ (2.6)	$ (2.6)	$—	$ —	$ —
Fuel products segment:						
Crude oil swaps	14.9	(1.6)	13.3	—	—	—
Crude oil basis swaps	0.5	(5.9)	(5.4)	0.4	(0.4)	—
Crude oil percentage basis swaps	0.7	(0.8)	(0.1)	0.2	(0.2)	—
Crude oil options	1.0	(1.1)	(0.1)	0.8	(0.8)	—
Natural gas swaps	0.2	(0.4)	(0.2)	—	—	—
Total derivative instruments not designated as hedges	17.3	(12.4)	4.9	1.4	(1.4)	—
Total derivative instruments	$17.3	$ (12.4)	$ 4.9	$1.4	$ (1.4)	$ —

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, 2016, and December 31, 2015 (in millions):

	June 30, 2016			December 31, 2015		
	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	$(6.4)	$ 2.6	$ (3.8)	$(14.9)	$ —	$ (14.9)
Natural gas collars	(0.2)	—	(0.2)	(0.9)	—	(0.9)
Fuel products segment:						
Crude oil swaps	(7.1)	1.6	(5.5)	(5.2)	—	(5.2)
Crude oil basis swaps	(5.7)	5.9	0.2	(0.7)	0.4	(0.3)
Crude oil percentage basis swaps	(2.0)	0.8	(1.2)	(6.9)	0.2	(6.7)
Crude oil options	(1.1)	1.1	—	(1.1)	0.8	(0.3)
Gasoline crack spread swaps	—	—	—	(4.3)	—	(4.3)
Natural gas swaps	(0.3)	0.4	0.1	(1.3)	—	(1.3)

Total derivative instruments not designated as hedges	(22.8)	12.4	(10.4)	(35.3)	1.4	(33.9)
Total derivative instruments	$(22.8)	$ 12.4	$ (10.4)	$(35.3)	$ 1.4	$ (33.9)

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 credit exposure related to these derivative instruments is represented by the fair value of contracts reported as derivative assets. As of June 30, 2016, the Company had three counterparties in which the derivatives held were net assets, totaling $4.9 million. As of December 31, 2015, the Company had no counterparties in which the derivatives held were net assets. 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 Baa1 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, 2016, or December 31, 2015. The Company's contracts with these counterparties allow for netting of derivative instruments executed under each contract. Collateral received from counterparties is reported in other current liabilities, and collateral held by counterparties is reported in deposits on the Company's condensed consolidated balance sheets and is not netted against derivative assets or liabilities. As of June 30, 2016, and December 31, 2015, the Company had provided its counterparties with no collateral. For financial reporting purposes, the Company does not offset the collateral provided to a counterparty against the fair value of its obligation to that counterparty. Any outstanding collateral is released to the Company upon settlement of the related derivative instrument liability.

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 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.

Derivative Instruments Designated as Cash Flow Hedges

The Company accounts for certain derivatives hedging purchases of crude oil and sales of gasoline, diesel and jet fuel swaps 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 unrealized 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 unrealized 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 income (loss) and unaudited condensed consolidated statements of partners' capital as of and for the three months ended June 30, 2016 and 2015, 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,	
	2016	2015		2016	2015		2016	2015
Specialty products segment:								
Crude oil swaps	$ —	$ —	Cost of sales	$ (0.5)	$ 1.6	Unrealized/ Realized	$ —	$ —
Fuel products segment:								
Crude oil swaps	(4.5)	(2.7)	Cost of sales	(12.3)	(53.2)	Unrealized/ Realized	—	—
Gasoline swaps	—	2.7	Sales	—	19.3	Unrealized/ Realized	—	—
Diesel swaps	4.5	(1.4)	Sales	15.1	39.8	Unrealized/ Realized	—	—
Jet fuel swaps	—	0.3	Sales	—	4.0	Unrealized/ Realized	—	—
Total	$ —	$ (1.1)		$ 2.3	$ 11.5		$ —	$ —

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, 2016 and 2015, 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,	
	2016	2015		2016	2015		2016	2015
Specialty products segment:								
Crude oil swaps	$ —	$ —	Cost of sales	$ (1.2)	$ 1.2	Unrealized/ Realized	$ —	$ —
Fuel products segment:								
Crude oil swaps	(5.8)	(9.0)	Cost of sales	(25.5)	(74.7)	Unrealized/ Realized	—	(0.2)
Gasoline swaps	—	3.5	Sales	—	33.3	Unrealized/ Realized	—	0.7
Diesel swaps	5.8	(1.3)	Sales	31.1	44.6	Unrealized/ Realized	—	—
Jet fuel swaps	—	0.6	Sales	—	5.4	Unrealized/ Realized	—	—
Total	$ —	$ (6.2)		$ 4.4	$ 9.8		$ —	$ 0.5

The effective portion of the cash flow hedges classified in accumulated other comprehensive loss was gains of $2.0 million and $6.4 million as of June 30, 2016, and December 31, 2015, respectively. Absent a change in the fair market value of the underlying transactions, except for any underlying transactions pertaining to the payment of interest on existing financial instruments, the following other comprehensive income at June 30, 2016, will be reclassified to earnings by December 31, 2016, with balances being recognized as follows (in millions):

Year	Accumulated Other Comprehensive Income
2016	$ 2.0
Total	$ 2.0

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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.

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 gains (losses) in its unaudited condensed consolidated statements of operations for the three and six months ended June 30, 2016 and 2015, related to its derivative instrument designated as a fair value hedge (in millions):

	Location of Loss of Derivative	Amount of Loss Recognized in Net Income (Loss)				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,				Three Months Ended June 30,		Six Months Ended June 30,	
		2016	2015	2016	2015			2016	2015	2016	2015
Swaps not allocated to a specific segment:											
Interest rate swap	Interest expense	$0.1	$0.1	$0.2	$0.3	2022 Notes	Interest income	$ —	$ —	$ —	$ —
Total		$0.1	$0.1	$0.2	$0.3			$ —	$ —	$ —	$ —

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 unrealized 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 recorded to realized gain (loss) on derivative instruments in the unaudited condensed consolidated statements of operations. The Company has entered into crude oil basis swaps that do not qualify as cash flow hedges for accounting purposes as they were not entered into simultaneously with a corresponding NYMEX WTI derivative contract. Additionally, the Company has entered into natural gas collars, 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 gasoline and diesel sales at the Company's refineries.

The amount reclassified from accumulated other comprehensive loss into earnings, as a result of the discontinuance of cash flow hedge accounting for certain crude oil, gasoline, jet fuel and diesel derivative instruments at the Shreveport refinery because it was no longer probable that the original forecasted transaction would occur by the end of the originally specified time period, caused the Company to recognize the following gains in the unaudited condensed consolidated statements of operations for the six months ended June 30, 2016 and 2015 (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Realized gain (loss) on derivative instruments	$ —	$ 1.2	$ —	$ 2.4

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The Company recorded the following gains (losses) in its unaudited condensed consolidated statements of operations for the three months ended June 30, 2016 and 2015, related to its derivative instruments not designated as hedges (in millions):

Type of Derivative	Amount of Gain (Loss) Recognized in Realized Loss on Derivative Instruments Three Months Ended June 30,		Amount of Gain (Loss) Recognized in Unrealized Gain on Derivative Instruments Three Months Ended June 30,	
	2016	2015	2016	2015
Specialty products segment:				
Natural gas swaps	$ (3.2)	$ (2.5)	$ 6.6	$ 3.1
Natural gas collars	(0.4)	—	0.5	—
Platinum swaps	—	—	—	(0.2)
Fuel products segment:				
Crude oil swaps	0.1	7.7	11.5	5.2
Crude oil basis swaps	0.1	—	(2.3)	2.2
Crude oil percentage basis swaps	(0.5)	—	5.2	—
Crude oil options	(1.5)	—	0.8	—
Gasoline swaps	—	(16.5)	—	(7.0)
Gasoline crack spread swaps	—	(3.9)	—	(1.7)
Diesel swaps	—	1.2	—	(3.8)
Diesel crack spread swaps	—	—	—	7.4
Natural gas swaps	(0.6)	—	1.5	—
Total	$ (6.0)	$ (14.0)	$ 23.8	$ 5.2

The Company recorded the following gains (losses) in its unaudited condensed consolidated statements of operations for the six months ended June 30, 2016 and 2015, related to its derivative instruments not designated as hedges (in millions):

Type of Derivative	Amount of Gain (Loss) Recognized in Realized Loss on Derivative Instruments Six Months Ended June 30,		Amount of Gain (Loss) Recognized in Unrealized Gain (Loss) on Derivative Instruments Six Months Ended June 30,	
	2016	2015	2016	2015
Specialty products segment:				
Natural gas swaps	$ (6.6)	$ (4.6)	$ 8.5	$ (0.1)
Natural gas collars	(0.7)	—	0.6	—
Platinum swaps	—	—	—	(0.3)
Fuel products segment:				
Crude oil swaps	(0.8)	(40.6)	13.0	55.4
Crude oil basis swaps	0.1	1.0	(4.9)	1.8
Crude oil percentage basis swaps	(4.4)	—	5.4	—
Crude oil options	(1.5)	—	0.2	—
Crude oil futures	(2.0)	—	—	—
Gasoline swaps	—	(18.4)	—	(8.2)
Gasoline crack spread swaps	(1.2)	(4.7)	4.3	(3.2)
Diesel swaps	—	59.2	—	(67.2)

Diesel crack spread swaps	—	0.9	—	1.0
Jet fuel swaps	—	1.6	—	(1.6)
Natural gas swaps	(1.2)	—	1.3	(0.3)
Total	$ (18.3)	$ (5.6)	$ 28.4	$ (22.7)

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Derivative Positions — Specialty Products Segment

Natural Gas Swap Contracts

At June 30, 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
Third Quarter 2016	1,380,000	$ 4.26
Fourth Quarter 2016	1,540,000	$ 4.14
Calendar Year 2017	4,950,000	$ 3.85
Total	7,870,000	
Average price		$ 3.98

At December 31, 2015, 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 2016	1,580,000	$ 4.24
Second Quarter 2016	1,380,000	$ 4.26
Third Quarter 2016	1,380,000	$ 4.26
Fourth Quarter 2016	1,540,000	$ 4.14
Calendar Year 2017	4,950,000	$ 3.85
Total	10,830,000	
Average price		$ 4.05

Natural Gas Collars

At June 30, 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 Collars by Expiration Dates	MMBtu	Average Bought Call ($/MMBtu)	Average Sold Put ($/MMBtu)
Third Quarter 2016	180,000	$ 4.25	$ 3.89
Fourth Quarter 2016	60,000	$ 4.25	$ 3.89
Total	240,000		
Average price		$ 4.25	$ 3.89

At December 31, 2015, 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 Collars by Expiration Dates	MMBtu	Average Bought Call ($/MMBtu)	Average Sold Put ($/MMBtu)
First Quarter 2016	180,000	$ 4.25	$ 3.89
Second Quarter 2016	180,000	$ 4.25	$ 3.89
Third Quarter 2016	180,000	$ 4.25	$ 3.89
Fourth Quarter 2016	60,000	$ 4.25	$ 3.89
Total	600,000		
Average price		$ 4.25	$ 3.89

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Derivative Positions — Fuel Products Segment

Crude Oil Swap Contracts

At June 30, 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)
Third Quarter 2016	398,894	4,336	$ 39.46
Fourth Quarter 2016	398,894	4,336	$ 39.46
Calendar Year 2017	1,297,977	3,556	$ 48.87
Total	2,095,765		
Average price			$ 45.29

At June 30, 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)
Calendar Year 2017	528,520	1,448	$ 41.56
Total	528,520		
Average price			$ 41.56

At December 31, 2015, 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 2016	29,120	320	$ 44.06
Second Quarter 2016	29,120	320	$ 44.06
Third Quarter 2016	29,440	320	$ 44.06
Fourth Quarter 2016	29,440	320	$ 44.06
Calendar Year 2017	630,720	1,728	$ 54.94
Total	747,840		
Average price			$ 53.24

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 LLS and NYMEX WTI. At June 30, 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)
Third Quarter 2016	460,000	5,000	$ 1.80
Fourth Quarter 2016	460,000	5,000	$ 1.80
Total	920,000		
Average differential			$ 1.80

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At December 31, 2015, 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 2016	182,000	2,000	$ 2.40
Second Quarter 2016	182,000	2,000	$ 2.40
Third Quarter 2016	184,000	2,000	$ 2.40
Fourth Quarter 2016	184,000	2,000	$ 2.40
Total	732,000		
Average differential			$ 2.40

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, 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)
Third Quarter 2016	1,196,000	13,000	$ (13.16)
Fourth Quarter 2016	1,196,000	13,000	$ (13.16)
Calendar Year 2017	2,555,000	7,000	$ (13.22)
Total	4,947,000		
Average differential			$ (13.19)

At December 31, 2015, 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 2016	91,000	1,000	$ (14.10)
Second Quarter 2016	91,000	1,000	$ (14.10)
Third Quarter 2016	92,000	1,000	$ (14.10)
Fourth Quarter 2016	92,000	1,000	$ (14.10)
Calendar Year 2017	365,000	1,000	$ (13.70)
Total	731,000		
Average differential			$ (13.90)

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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, 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)	
Third Quarter 2016	736,000	8,000	73.5	%
Fourth Quarter 2016	736,000	8,000	73.5	%
Calendar Year 2017	1,095,000	3,000	72.3	%
Total	2,567,000			
Average percentage			73.0	%

At December 31, 2015, 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 2016	728,000	8,000	73.5	%
Second Quarter 2016	728,000	8,000	73.5	%
Third Quarter 2016	736,000	8,000	73.5	%
Fourth Quarter 2016	736,000	8,000	73.5	%
Calendar Year 2017	730,000	2,000	73.0	%
Total	3,658,000			
Average percentage			73.4	%

Crude Oil Option Contracts

The Company has entered into derivative instruments to mitigate the risk of future changes in the price of NYMEX WTI crude oil. At June 30, 2016, the Company had the following derivatives related to crude oil call option purchases in its fuel products segment, none of which are designated as hedges:

Crude Oil Option Contracts by Expiration Dates	Barrels Purchased	BPD	Average Bought Call ($/Bbl)
Fourth Quarter 2016	350,000	3,804	$ 55.00
Total	350,000		
Average price			$ 55.00

At December 31, 2015, the Company had the following derivatives related to crude oil call option purchases in its fuel products segment, none of which are designated as hedges:

Crude Oil Option Contracts by Expiration Dates	Barrels Purchased	BPD	Average Bought

			Call ($/Bbl)
Fourth Quarter 2016	350,000	3,804	$ 55.00
Total	350,000		
Average price			$ 55.00

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Gasoline Crack Spread Swap Contracts

At December 31, 2015, 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 2016	873,000	9,593	$ 8.98
Total	873,000		
Average price			$ 8.98

Natural Gas Swap Contracts

At June 30, 2016, the Company had the following derivatives related to natural gas purchases in its fuel products segment, none of which are designated as hedges:

Natural Gas Swap Contracts by Expiration Dates	MMBtu	$/MMBtu
Third Quarter 2016	606,000	$ 3.03
Fourth Quarter 2016	790,000	$ 3.02
Total	1,396,000	
Average price		$ 3.02

At December 31, 2015, the Company had the following derivatives related to natural gas purchases in its fuel products segment, none of which are designated as hedges:

Natural Gas Swap Contracts by Expiration Dates	MMBtu	$/MMBtu
First Quarter 2016	603,000	$ 3.01
Second Quarter 2016	603,000	$ 2.99
Third Quarter 2016	606,000	$ 3.03
Fourth Quarter 2016	790,000	$ 3.02
Total	2,602,000	
Average price		$ 3.01

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.

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 derivative instruments consist of over-the-counter ("OTC") contracts, which are not traded on a public exchange. Substantially all of the Company's derivative instruments are with counterparties that have long-term credit ratings of at least Baa1 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, the Company uses 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, 2016, the Company's net asset was increased by approximately $0.6 million and net liability was reduced by approximately $0.8 million. As a result of applying the CVA at December 31, 2015, the Company's net liability was reduced by approximately $1.2 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 non-performance 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, 2016, the Company's investments associated with its pension plan (as such term is hereinafter defined) primarily consisted of mutual funds. The mutual funds are categorized as Level 2 because inputs used in their valuation are not quoted prices in active markets that are indirectly observable and 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 third-party administrator. Plan investments can be redeemed within a short time frame (10 or so business days), if requested. See Note 11 for further information on pension assets.

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 6 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, 2016, and December 31, 2015, were as follows (in millions):

	June 30, 2016				December 31, 2015			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Derivative assets:								
Crude oil swaps	$—	$—	$13.3	$13.3	$—	$—	$—	$—
Crude oil basis swaps	—	—	(5.4)	(5.4)	—	—	—	—
Crude oil percentage basis swaps	—	—	(0.1)	(0.1)	—	—	—	—
Crude oil options	—	—	(0.1)	(0.1)	—	—	—	—
Natural gas swaps	—	—	(2.8)	(2.8)	—	—	—	—
Total derivative assets	—	—	4.9	4.9	$—	$—	$—	$—
Pension plan investments	0.4	50.2	—	50.6	0.4	47.1	—	47.5
Total recurring assets at fair value	$0.4	$50.2	$4.9	$55.5	$0.4	$47.1	$—	$47.5
Liabilities:								
Derivative liabilities:								
Crude oil swaps	$—	$—	$(5.5)	$(5.5)	$—	$—	$(5.2)	$(5.2)
Crude oil basis swaps	—	—	0.2	0.2	—	—	(0.3)	(0.3)
Crude oil percentage basis swaps	—	—	(1.2)	(1.2)	—	—	(6.7)	(6.7)
Crude oil options	—	—	—	—	—	—	(0.3)	(0.3)
Gasoline crack spread swaps	—	—	—	—	—	—	(4.3)	(4.3)
Natural gas swaps	—	—	(3.7)	(3.7)	—	—	(16.2)	(16.2)
Natural gas collars	—	—	(0.2)	(0.2)	—	—	(0.9)	(0.9)
Total derivative liabilities	—	—	(10.4)	(10.4)	—	—	(33.9)	(33.9)
RINs Obligation	—	(114.7)	—	(114.7)	—	(88.4)	—	(88.4)
Total recurring liabilities at fair value	$—	$(114.7)	$(10.4)	$(125.1)	$—	$(88.4)	$(33.9)	$(122.3)

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, 2016 and 2015 (in millions):

	Six Months Ended June 30,	
	2016	2015
Fair value at January 1,	$(33.9)	$17.6
Realized loss on derivative instruments	18.3	5.1
Unrealized gain (loss) on derivative instruments	28.4	(22.7)
Interest expense, net	(0.2)	(0.3)
Change in fair value of cash flow hedges	—	(6.2)
Settlements	(18.1)	(10.6)
Transfers in (out) of Level 3	—	—
Fair value at June 30,	$(5.5)	$(17.1)
Total gain (loss) included in net income (loss) attributable to changes in unrealized gain (loss) relating to financial assets and liabilities held as of June 30,	$28.4	$(22.7)

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 realized gain (loss) on derivative instruments in 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 realized 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. See Note 5 for further information on goodwill impairment.

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

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

Debt

The estimated fair value of long-term debt at June 30, 2016, and December 31, 2015, consists primarily of the 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 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 related party note payable 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, 2016, and December 31, 2015, were as follows (in millions):

		June 30, 2016		December 31, 2015	
	Level	Fair Value	Carrying Value	Fair Value	Carrying Value
Financial Instrument:					
Senior notes	1	$1,128.8	$ 1,550.3	$1,095.8	$ 1,230.8
Senior notes	2	$452.0	$ 383.6	$294.1	$ 317.6
Revolving credit facility	3	$0.1	$ 0.1	$105.1	$ 105.1
Note payable — related party	3	$39.9	$ 39.9	$73.5	$ 73.5
Capital lease and other obligations	3	$45.6	$ 45.6	$46.4	$ 46.4

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10. Partners' Capital

The Company entered into an Equity Placement Agreement with various sales agents under which the Company issued and sold, from time to time, common units representing limited partner interests, having an aggregate offering price of up to $300.0 million through one or more sales agents. The Equity Placement Agreement expired in May 2016. The Equity Placement Agreement provided the Company the right, but not the obligation, to sell common units on an ongoing basis, at prices the Company deemed appropriate. These sales were made pursuant to the terms of the Equity Placement Agreement between the Company and the sales agents. The net proceeds from any sales under this agreement were used for general partnership purposes, including, among other things, repayment of indebtedness, working capital and capital expenditures. The Company's general partner contributed its proportionate capital contribution to retain its 2% general partner interest. The Company had no sales of its common units during the three and six months ended June 30, 2016, and the three months ended June 30, 2015. For the six months ended June 30, 2015, the Company sold 307,985 common units for net proceeds of approximately $7.6 million. Underwriting discounts totaled approximately $0.1 million, and the Company's general partner contributed $0.2 million to maintain its general partner interest.

The Company's distribution policy is defined in its partnership agreement. In April 2016, Calumet GP, LLC's Board of Directors determined to suspend payment of the Company's quarterly cash distribution. Calumet GP, LLC's Board of Directors will continue to evaluate the Company's ability to reinstate the distribution. For the three months ended June 30, 2016, the Company made no distributions to its partners. For the three months ended June 30, 2015, the Company made distributions of $57.3 million, to its partners. In the six months ended June 30, 2016 and 2015, the Company made distributions of $57.4 million and $110.0 million, respectively, to its partners.

For the three and six months ended June 30, 2016, the general partner was allocated no incentive distribution rights. For the three and six months ended June 30, 2015, the general partner was allocated $4.2 million and $8.4 million, respectively, in incentive distribution rights.

11. Employee Benefit Plans

The components of net periodic benefit cost (income) for the three and six months ended June 30, 2016 and 2015, were as follows (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Service cost	$—	$0.2	$—	$0.3
Interest cost	0.7	0.6	1.3	1.3
Expected return on assets	(0.8)	(0.9)	(1.6)	(1.7)
Amortization of net loss	0.1	0.2	0.1	0.4
Net periodic benefit cost (income)	$—	$0.1	$(0.2)	$0.3

At June 30, 2016, and December 31, 2015, the Company's investments associated with its pension plan primarily consisted of (i) cash and cash equivalents and (ii) mutual funds. The mutual funds are categorized as Level 2 because inputs used in their valuation are not quoted prices in active markets that are indirectly observable and are valued at the NAV of shares in each fund held by the pension plan at quarter end as provided by the third-party administrator. See Note 9 for the definitions of Levels 1, 2 and 3. The Company's pension plan assets measured at fair value at June 30, 2016, and December 31, 2015, were as follows (in millions):

	June 30, 2016		December 31, 2015	
	Level 1	Level 2	Level 1	Level 2
Cash and cash equivalents	$0.4	$—	$0.4	$—
Domestic equities	—	9.9	—	9.6
Foreign equities	—	9.3	—	9.2

Fixed income	—	31.0	—	28.3
	$0.4	$50.2	$0.4	$47.1

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.

12. Accumulated Other Comprehensive Loss

The table below sets forth a summary of reclassification adjustments out of accumulated other comprehensive income (loss) in the Company's unaudited condensed consolidated statements of operations for the three and six months ended June 30, 2016 and 2015 (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,		
	2016	2015	2016	2015	
Derivative gains (losses) reflected in gross profit:					
	$ 15.1	$ 63.1	$ 31.1	$ 83.3	Sales
	(12.8)	(51.6)	(26.7)	(73.5)	Cost of sales
	$ 2.3	$ 11.5	$ 4.4	$ 9.8	Total
Amortization of defined benefit pension plans:					
Amortization of net loss	$ (0.1)	$ (0.2)	$ (0.1)	$ (0.4)	(1)
	$ (0.1)	$ (0.2)	$ (0.1)	$ (0.4)	Total

(1) This accumulated other comprehensive loss component is included in the computation of net periodic benefit cost (income). See Note 11 for additional details.

13. 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, 2016 and 2015 (in millions, except unit and per unit data):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Numerator for basic and diluted earnings per limited partner unit:				
Net income (loss)	$(147.9)	$ 2.5	$(215.6)	$ 26.3
General partner's interest in net income (loss)	(2.9)	—	(4.3)	0.5
General partner's incentive distribution rights	—	4.2	—	8.4
Net income (loss) available to limited partners	$(145.0)	$ (1.7)	$(211.3)	$ 17.4
Denominator for basic and diluted earnings per limited partner unit:				
Basic weighted average limited partner units outstanding	76,761,504	76,092,517	76,491,775	73,675,251
Effect of dilutive securities:				
Participating securities — phantom units	—	—	—	54,938
Diluted weighted average limited partner units outstanding (1)	76,761,504	76,092,517	76,491,775	73,730,189
Limited partners' interest basic and diluted net income (loss) per unit	$(1.89)	$ (0.02)	$(2.76)	$ 0.23

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(1) Total diluted weighted average limited partner units outstanding excludes 0.1 million and 0.2 million of dilutive phantom units for the three and six months ended June 30, 2016, respectively. Total diluted weighted average limited partner units outstanding excludes 0.1 million of dilutive phantom units for the three months ended June 30, 2015.

14. 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 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 2015 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 and six months ended June 30, 2016 and 2015, is as follows (in millions):

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)

Three Months Ended June 30, 2015	Specialty Products	Fuel Products	Oilfield Services	Combined Segments	Eliminations	Consolidated Total
Sales:						
External customers	$ 370.6	$ 715.1	$ 70.5	$ 1,156.2	$ —	$ 1,156.2
Intersegment sales	1.7	12.1	—	13.8	(13.8)	—
Total sales	$ 372.3	$ 727.2	$ 70.5	$ 1,170.0	$ (13.8)	$ 1,156.2
Loss from unconsolidated affiliates	$ —	$ (8.1)	$ (0.1)	$ (8.2)	$ —	$ (8.2)
Adjusted EBITDA	$ 63.2	$ 46.0	$ (14.2)	$ 95.0	$ —	$ 95.0
Reconciling items to net income:						
Depreciation and amortization	16.7	20.2	5.7	42.6	—	42.6
Realized loss on derivatives, not reflected in net income or settled in a prior period	(1.6)	(11.0)	—	(12.6)	—	(12.6)
Unrealized gain on derivatives						(5.2)
Interest expense						27.4
Debt extinguishment costs						46.6
Non-cash equity based compensation and other non-cash items						2.8
Income tax benefit						(9.1)
Net income						$ 2.5

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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)

Six Months Ended June 30, 2015	Specialty Products	Fuel Products	Oilfield Services	Combined Segments	Eliminations	Consolidated Total
Sales:						
External customers	$ 732.2	$ 1,283.4	$ 159.2	$ 2,174.8	$ —	$ 2,174.8
Intersegment sales	3.0	25.0	—	28.0	(28.0)	—
Total sales	$ 735.2	$ 1,308.4	$ 159.2	$ 2,202.8	$ (28.0)	$ 2,174.8
Loss from unconsolidated affiliates	$ —	$ (12.5)	$ (0.2)	$ (12.7)	$ —	$ (12.7)
Adjusted EBITDA	$ 129.1	$ 109.1	$ (18.3)	$ 219.9	$ —	$ 219.9
Reconciling items to net income:						
Depreciation and amortization	32.6	40.2	11.3	84.1	—	84.1
Realized loss on derivatives, not reflected in net income or settled in a prior period	(1.2)	(5.3)	—	(6.5)	—	(6.5)
Unrealized loss on derivatives						22.7
Interest expense						54.4
Debt extinguishment costs						46.6
Non-cash equity based compensation and other non-cash items						6.2
Income tax benefit						(13.9)
Net income						$ 26.3

b. Geographic Information

International sales accounted for less than 10% of consolidated sales in each of the three and six months ended June 30, 2016 and 2015. 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, 2016 and 2015 (dollars in millions):

	Three Months Ended June 30,			
	2016		2015	
Specialty products:				
Lubricating oils	$146.3	15.0 %	$158.1	13.7 %
Solvents	61.1	6.3 %	81.6	7.1 %
Waxes	36.3	3.7 %	33.9	2.9 %
Packaged and synthetic specialty products	76.6	7.9 %	88.4	7.6 %
Other	12.1	1.3 %	8.6	0.8 %
Total	$332.4	34.2 %	$370.6	32.1 %
Fuel products:				
Gasoline	$228.0	23.4 %	$302.6	26.2 %
Diesel	238.6	24.5 %	251.0	21.7 %
Jet fuel	25.8	2.7 %	37.9	3.3 %
Asphalt, heavy fuel oils and other	126.8	13.0 %	123.6	10.7 %
Total	$619.2	63.6 %	$715.1	61.9 %
Oilfield services:				
Total	$21.3	2.2 %	$70.5	6.0 %
Consolidated sales	$972.9	100.0%	$1,156.2	100.0%

The following table sets forth the major product category sales for the six months ended June 30, 2016 and 2015 (dollars in millions):

	Six Months Ended June 30,			
	2016		2015	
Specialty products:				
Lubricating oils	$275.5	16.3 %	$307.9	14.2 %
Solvents	117.0	6.9 %	167.8	7.7 %
Waxes	63.5	3.8 %	72.9	3.4 %
Packaged and synthetic specialty products	157.5	9.3 %	168.9	7.8 %
Other	19.6	1.3 %	14.7	0.7 %
Total	$633.1	37.6 %	$732.2	33.8 %
Fuel products:				
Gasoline	$390.2	23.1 %	$548.9	25.1 %
Diesel	377.5	22.4 %	464.9	21.4 %
Jet fuel	49.2	2.9 %	76.1	3.5 %
Asphalt, heavy fuel oils and other	182.2	10.8 %	193.5	8.9 %
Total	$999.1	59.2 %	$1,283.4	58.9 %
Oilfield services:				
Total	$53.7	3.2 %	$159.2	7.3 %
Consolidated sales	$1,685.9	100.0%	$2,174.8	100.0%

d. Major Customers

During the three and six months ended June 30, 2016 and 2015, 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, 2016 and 2015, the Company had two suppliers that supplied approximately 60.7% and 49.5%, respectively, of its crude oil supply. During the six months ended June 30, 2016 and 2015, the Company had two suppliers that supplied approximately 57.0% and 48.8%, respectively, of its crude oil supply.

15. Subsequent Events

The fair value of the Company’s derivatives that were outstanding as of June 30, 2016, decreased by approximately $18.0 million subsequent to June 30, 2016, to a net liability of approximately $24.0 million. The fair value of the Company’s senior notes has decreased by approximately $11.0 million subsequent to June 30, 2016.

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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, 2016 and 2015. Investors should read the following discussion and analysis of the financial condition and results of operations of the Company in conjunction with our 2015 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 2016 Update

Outlook and Trends

Commodity markets and corresponding fluctuations in product margins were volatile during 2015 and the first half of 2016, with the average price per barrel of New York Mercantile Exchange West Texas Intermediate ("NYMEX WTI") crude oil decreasing more than 45% in 2015 and increasing approximately 8% in the second quarter of 2016 as compared to the fourth quarter 2015. We expect this volatility to continue for the remainder of 2016. Below are factors that have impacted or may impact our results of operations during 2016:

- Gasoline margins have been volatile, due mainly to fluctuations in domestic gasoline inventories. Presently, domestic gasoline inventories are elevated, when compared to the five-year rolling average. Diesel margins have also been negatively impacted by elevated domestic diesel inventory levels. While overall demand for motor fuels was seasonally robust in the second quarter 2016, the independent refining complex continues to operate at elevated utilization levels which, together with the impact of refined product imports, has resulted in a near-term market dynamic in which markets remain well supplied. We expect gasoline margins to decline seasonally due to high inventory levels and the end to the summer driving season. Diesel margins are expected to improve as inventory levels have declined.
- Environmental regulations continue to affect our margins in the form of the increasing 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. As a result, the 26% increase in the price of RINs during the second quarter 2016 adversely affected our results of operations. It is not possible to predict what future volumes or costs may be, but given the increase in required volumes and the volatile price of RINs, we continue to anticipate that RINs have the potential to remain a significant expense for our fuel products segment, assuming current market prices for RINs.
- Asphalt demand is expected to accelerate during the third quarter 2016 due to the seasonality of the road construction and roofing industries, which have shown these types of trends of increased seasonal demand in prior years.
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Heavy sour crude oil discounts are expected to remain wide 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.
- Volatility in crude oil and natural gas prices negatively impacted our oilfield services segment, with a more than 38% decrease in the average U.S. land-based rig count in the first half of 2016. We anticipate the remainder of 2016 will be challenging, and we expect to continue to adapt our cost structure to market conditions, which we believe will position us favorably if the market ultimately recovers.

A further decline in market prices of crude oil, refined products or continued narrow product margins may negatively impact the results of our operations which could result in a long-lived asset or goodwill impairment as experienced in the second quarter 2016. We recorded a $113.9 million loss on the sale of Dakota Prairie Refining, LLC ("Dakota Prairie"), our joint venture with MDU Resources, Inc. ("MDU"), and an asset impairment charge of $33.4 million related to our Great Falls and San Antonio fuels refineries.

Financial Results

We reported a net loss of $147.9 million in the second quarter 2016, versus net income of $2.5 million in the second quarter 2015. We reported Adjusted EBITDA (as defined in "Non-GAAP Financial Measures") of $70.0 million in the second quarter 2016, versus $95.0 million in the second quarter 2015. We used $51.7 million of cash flow from operations in the six months ended June 30, 2016, versus generating cash flow from operations of $160.0 million in the six months ended June 30, 2015. Distributable Cash Flow ("DCF") (as defined in "Non-GAAP Financial Measures") was $31.7 million in the second quarter 2016, compared to $73.3 million in the second quarter 2015.

Our net loss for the second quarter 2016 includes, but is not limited to, the impact of five items: (1) a $113.9 million non-cash loss on sale of our 50% joint venture interest in Dakota Prairie on June 27, 2016; (2) a $33.4 million goodwill impairment charge; (3) a favorable lower of cost or market ("LCM") inventory adjustment of $36.3 million; (4) net expense of $8.2 million related to the Partnership's ongoing compliance with the U.S. Renewable Fuel Standard ("RFS"); and (5) a $7.1 million loss from unconsolidated affiliates primarily related to our divested 50% joint venture interest in Dakota Prairie, which was included in results from operations until divested on June 27, 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 provided by (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 2016, contributing to fluctuations in refined product margins. The average price of NYMEX WTI crude oil decreased more than 20% in the second quarter 2016, when compared to the prior year period. In the second quarter 2016, the average price differential per barrel between Western Canadian Select ("WCS") and NYMEX WTI averaged $12 per barrel below NYMEX WTI, versus $9 per barrel below NYMEX WTI in the second quarter 2015. 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 2016, we processed 35,600 bpd of heavy Canadian crude oil, versus 24,600 bpd in the second quarter 2015.

Specialty products segment Adjusted EBITDA was $59.0 million in the second quarter 2016, versus $63.2 million in the second quarter 2015, due mainly to volatility in feedstock costs that impacted margin capture in the period and a $17.4 million favorable LCM inventory adjustment. Specialty products represented approximately 20% of total production in the second quarter 2016. Given an increase in crude oil prices during the second quarter 2016, margins within the specialty products segment were impacted. Total specialty products segment sales volumes increased 15.6% in the second quarter 2016, when compared to the second quarter 2015.

Fuel products segment Adjusted EBITDA was $18.9 million during the second quarter 2016, versus $46.0 million in the second quarter 2015, due primarily to a material year over year decline in benchmark refined products margins and elevated RFS compliance costs, partially offset by a $22.3 million favorable LCM inventory adjustment. Fuel products represented 80% of total production during the second quarter 2016. Gasoline and diesel margins have been volatile, declining well below prior-year levels. A combination of elevated utilization within the domestic refining complex, combined with higher imports of refined products into the U.S., has led to an evolving market dynamic in which elevated crude oil inventory levels have begun to translate into elevated domestic refined product inventory levels, as regularly reported by the U.S. Department of Energy.

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 2016, the Gulf Coast crack spread averaged approximately $13 per barrel compared to approximately $22 per barrel in the prior year period, an approximate 41% decline. The Gulf Coast ULSD crack spread averaged approximately $11 per barrel during the second quarter 2016, compared to approximately $19 per barrel in the prior year period. The Gulf Coast gasoline crack spread averaged approximately $14 per barrel during the second quarter 2016, compared to approximately $25 per barrel in the prior year period. Total fuel products segment sales volumes increased 26.2% in the second quarter 2016, when compared to the second quarter 2015.

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. Given a colder than normal April, asphalt sales accelerated beginning in May 2016, one month later than usual. As a result, we anticipate full-year asphalt sales to be heavily weighted in the third quarter 2016. 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 has continued to be negatively impacted by lower crude oil and natural gas prices, with a more than 53.5% decrease in the average U.S. land-based rig count in the second quarter 2016, when compared to the second quarter 2015. Additionally, our oilfield services segment had a $1.1 million favorable LCM inventory adjustment in the second quarter 2016. We anticipate the remainder of 2016 will be challenging, and we will continue to adapt our cost structure to market conditions, which we believe will position us favorably when the market ultimately recovers.

Suspension of Quarterly Cash Distribution

On April 15, 2016, we announced that the Board of Directors of our general partner unanimously voted to suspend the current quarterly cash distribution of $0.685 per unit, or $2.74 per unit on an annualized basis, effective for the quarter ended March 31, 2016, due to various factors, including current volatility in market conditions, and as part of a broader effort to maintain an adequate level of liquidity. The Board of Directors of our general partner intends to evaluate a reinstatement of a quarterly cash distribution in due course, taking into account a number of factors, including our liquidity requirements, the relative health of cash flows from operations, balance sheet leverage, debt instrument covenants, broader market conditions and the overall performance of our business. However, there can be no assurance that the reinstatement of distributions will occur in the near term. Until such time as our quarterly distribution exceeds the target distribution levels needed to result in distributions payable on the incentive distribution rights, no such amounts will be paid to the general partner as the holder of the incentive distribution rights.

Liquidity Update

As of June 30, 2016, we had availability under our revolving credit facility of $437.5 million, based on a $502.0 million borrowing base, $64.4 million in outstanding standby letters of credit and $0.1 million in outstanding borrowings. In addition, we had $32.2 million of cash on hand as of June 30, 2016. We believe we will continue to have sufficient liquidity from cash on hand, cash flow from operations, borrowing capacity and other means by which to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures.

Renewable Fuel Standard Update

Along with the broader refining industry, we remain subject to compliance costs under the 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 (“RVO”), the refiner can purchase blending credits in the open market, referred to as RINs.

During the second quarter 2016, we recognized RINs expense of $8.2 million, compared to a gain of $9.6 million for the second quarter 2015. Our gross RINs obligation, which includes RINs that are required to be secured through either blending or through the purchase of RINs in the open market, was 99 million RINs in 2015. For the full year 2016, we anticipate our gross RINs obligation will increase to 120 million RINs, given recent production capacity expansions at two of our fuel products refineries, excluding the potential for any subsequent hardship waivers that may or may not be granted by the EPA to any of our fuel refineries at a later time. We expect to be able to satisfy a portion of our 2016 gross RINs liability through internal blending efforts.

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. Estimated RINs obligations remain subject to fluctuations in fuels production volumes during the full year 2016.

In June 2016, we were notified by the EPA that our petition to receive retroactive exemption from compliance with the RFS at certain of our refineries had been granted for the full year 2014, given that compliance with RFS would result in undue economic hardship at these facilities. We are in the process of an assessment to determine which of our fuels refineries potentially could be eligible for economic hardship exemptions for the 2015 and 2016 calendar years.

Strategic Update

In August 2016, we announced a multi-year, self-help program that focuses on value creation through operations excellence and resource optimization. Under the program, we are pursuing a series of cost reduction initiatives, margin enhancing measures 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 earnings per year as compared to 2015, including $60 million to $75 million of which is expected to be realized by year-end 2016. For information on forward-looking non-GAAP 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
- 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, 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

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analyze the trends and performance of our core cash operations as well as make decisions regarding the allocation of resources to segments.

Results of Operations for the Three and Six Months Ended June 30, 2016 and 2015

Production Volume. The following table sets forth information about our combined operations, excluding Anchor and SOS. 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,		
	2016	2015	% Change	2016	2015	% Change
	(In bpd)			(In bpd)		
Total sales volume (1)	154,286	124,440	24.0 %	139,363	122,950	13.3 %
Total feedstock runs (2)	143,118	122,012	17.3 %	135,751	121,439	11.8 %
Facility production: (3)						
Specialty products:						
Lubricating oils	15,716	15,005	4.7 %	14,785	13,377	10.5 %
Solvents	7,823	8,359	(6.4)%	7,587	8,999	(15.7)%
Waxes	1,581	1,513	4.5 %	1,458	1,583	(7.9)%
Packaged and synthetic specialty products (4)	2,110	1,605	31.5 %	2,117	1,525	38.8 %
Other	1,799	1,434	25.5 %	1,354	1,164	16.3 %
Total	29,029	27,916	4.0 %	27,301	26,648	2.5 %
Fuel products:						
Gasoline	37,954	36,491	4.0 %	37,999	37,086	2.5 %
Diesel	40,057	28,649	39.8 %	35,202	29,432	19.6 %
Jet fuel	4,314	5,043	(14.5)%	4,995	5,047	(1.0)%
Asphalt, heavy fuels and other	32,941	26,601	23.8 %	30,590	24,442	25.2 %
Total	115,266	96,784	19.1 %	108,786	96,007	13.3 %
Total facility production (3)	144,295	124,700	15.7 %	136,087	122,655	11.0 %

(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 increase in total sales volume for the three months ended June 30, 2016 compared to the same period in 2015 is due primarily to increased sales volume of lubricating oils, solvents and waxes, partially offset by decreased sales of packaged and synthetic specialty products due to market conditions. Additionally, sales volumes of fuel products including asphalt increased as a result of increased production at the Great Falls refinery from the expansion project completed in 2016 and market conditions.

The increase in total sales volume for the six months ended June 30, 2016 compared to the same period in 2015 is due primarily to increased sales volume of lubricating oils, diesel and asphalt as a result of market conditions and increased production at the Great Falls refinery from the expansion project completed in 2016.

(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 increase in total feedstock runs for the three and six months ended June 30, 2016, compared to the same periods in 2015 is due primarily to increased feedstock runs at the Great Falls refinery from the expansion project completed in 2016 and improved operational reliability, partially offset by decreased feedstock runs related to the production of solvents as a result of market conditions.

(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

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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, 2016, compared to the same periods in 2015 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 provided by (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,	
	2016	2015	2016	2015
	(In millions)			
Sales	$972.9	$1,156.2	$1,685.9	$2,174.8
Cost of sales	841.6	953.5	1,468.4	1,776.9
Gross profit	131.3	202.7	217.5	397.9
Operating costs and expenses:				
Selling	26.2	37.8	56.7	76.2
General and administrative	24.8	31.7	52.4	70.9
Transportation	45.0	42.3	84.2	84.3
Taxes other than income taxes	4.2	4.0	9.9	8.0
Asset impairment	33.4	—	33.4	—
Other	0.3	3.2	2.3	6.1
Operating income (loss)	(2.6)	83.7	(21.4)	152.4
Other income (expense):				
Interest expense	(42.8)	(27.4)	(73.1)	(54.4)
Debt extinguishment costs	—	(46.6)	—	(46.6)
Realized loss on derivative instruments	(6.0)	(14.0)	(18.3)	(5.1)
Unrealized gain (loss) on derivative instruments	23.8	5.2	28.4	(22.7)
Loss from unconsolidated affiliates	(7.1)	(8.2)	(18.2)	(12.7)
Loss on sale of unconsolidated affiliates	(113.4)	—	(113.4)	—
Other	0.5	0.7	0.9	1.5
Total other expense	(145.0)	(90.3)	(193.7)	(140.0)
Net income (loss) before income taxes	(147.6)	(6.6)	(215.1)	12.4
Income tax expense (benefit)	0.3	(9.1)	0.5	(13.9)
Net income (loss)	$(147.9)	$2.5	$(215.6)	$26.3
EBITDA	$(61.0)	$103.4	$(59.4)	$184.8
Adjusted EBITDA	$70.0	$95.0	$76.6	$219.9
Distributable Cash Flow	$31.7	$73.3	$6.6	$171.9

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 Distributable Cash Flow to Net cash provided by (used in) operating activities, our most directly comparable liquidity measure. Both Net income (loss) and Net cash provided by (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.

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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 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.

The definitions of Adjusted EBITDA and Distributable Cash Flow that are presented in this Quarterly Report reflect the calculation of “Consolidated Cash Flow” contained in the indentures governing our 2021 Notes, 2022 Notes, 2023 Notes and 2021 Secured Notes (as defined in this Quarterly Report). We are required to report Consolidated Cash Flow to the holders of our 2021 Notes, 2022 Notes, 2023 Notes and 2021 Secured 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 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. As a result, reconciliation of forward-looking non-GAAP EBITDA to Net income (loss) is not available without unreasonable effort, and Calumet is unable to address the probable significance of information that is currently unavailable. It is expected that non-GAAP EBITDA, when reported, will reflect the exclusion of, among other things, interest expense, depreciation and amortization, and income taxes.

EBITDA, Adjusted EBITDA and Distributable Cash Flow should not be considered alternatives to net income (loss), operating income (loss), net cash provided by (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 provided by (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,	
	2016	2015	2016	2015
	(In millions)			
Reconciliation of Net income (loss) to EBITDA, Adjusted EBITDA and Distributable Cash Flow:				
Net income (loss)	$(147.9)	$2.5	$(215.6)	$26.3
Add:				
Interest expense	42.8	27.4	73.1	54.4
Debt extinguishment costs	—	46.6	—	46.6
Depreciation and amortization	43.8	36.0	82.6	71.4
Income tax expense (benefit)	0.3	(9.1)	0.5	(13.9)
EBITDA	$(61.0)	$103.4	$(59.4)	$184.8
Add:				
Unrealized (gain) loss on derivative instruments	$(23.8)	$(5.2)	$(28.4)	$22.7
Realized loss on derivatives, not included in net income (loss) or settled in a prior period	(2.3)	(12.6)	(4.4)	(6.5)
Amortization of turnaround costs	8.3	6.6	17.4	12.7
Impairment charges	33.4	—	33.4	—
Loss on sale of unconsolidated affiliates	113.9	—	113.9	—
Non-cash equity based compensation and other non-cash items	1.5	2.8	4.1	6.2
Adjusted EBITDA	$70.0	$95.0	$76.6	$219.9
Less:				
Replacement and environmental capital expenditures (1)	$3.3	$10.0	$11.1	$17.3
Cash interest expense (2)	40.1	25.9	68.5	51.5
Turnaround costs	1.7	3.2	8.1	5.9
Loss from unconsolidated affiliates	(7.1)	(8.3)	(18.2)	(12.8)
Income tax expense (benefit)	0.3	(9.1)	0.5	(13.9)
Distributable Cash Flow	$31.7	$73.3	$6.6	$171.9

(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,	
	2016	2015	2016	2015
	(In millions)			
Reconciliation of Segment Adjusted EBITDA to EBITDA and Net income (loss):				
Segment Adjusted EBITDA				
Specialty products Adjusted EBITDA	$59.0	$63.2	$117.5	$129.1
Fuel products Adjusted EBITDA	18.9	46.0	(27.1)	109.1
Oilfield Services Adjusted EBITDA	(7.9)	(14.2)	(13.8)	(18.3)
Total segment Adjusted EBITDA	$70.0	$95.0	$76.6	$219.9
Less:				
Unrealized gain (loss) on derivative instruments	$(23.8)	$(5.2)	$(28.4)	$22.7
Realized loss on derivatives, not included in net income (loss) or settled in a prior period	(2.3)	(12.6)	(4.4)	(6.5)
Amortization of turnaround costs	8.3	6.6	17.4	12.7
Impairment charges	33.4	—	33.4	—
Loss on sale of unconsolidated affiliate	113.9	—	113.9	—
Non-cash equity based compensation and other non-cash items	1.5	2.8	4.1	6.2
EBITDA	$(61.0)	$103.4	$(59.4)	$184.8
Less:				
Interest expense	$42.8	$27.4	$73.1	$54.4
Debt extinguishment costs	—	46.6	—	46.6
Depreciation and amortization	43.8	36.0	82.6	71.4
Income tax expense (benefit)	0.3	(9.1)	0.5	(13.9)
Net income (loss)	$(147.9)	$2.5	$(215.6)	$26.3

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	Six Months Ended June 30, 2016	2015
	(In millions)	
Reconciliation of Distributable Cash Flow, Adjusted EBITDA and EBITDA to Net cash provided by (used in) operating activities:		
Distributable Cash Flow	$6.6	$171.9
Add:		
Replacement and environmental capital expenditures [1]	11.1	17.3
Cash interest expense [2]	68.5	51.5
Turnaround costs	8.1	5.9
Loss from unconsolidated affiliates	(18.2)	(12.8)
Income tax expense (benefit)	0.5	(13.9)
Adjusted EBITDA	$76.6	$219.9
Less:		
Unrealized (gain) loss on derivative instruments	$(28.4)	$22.7
Realized loss on derivatives, not included in net income (loss) or settled in a prior period	(4.4)	(6.5)
Amortization of turnaround costs	17.4	12.7
Impairment charges	33.4	—
Loss on sale of unconsolidated affiliate	113.9	—
Non-cash equity based compensation and other non-cash items	4.1	6.2
EBITDA	$(59.4)	$184.8
Add:		
Unrealized (gain) loss on derivative instruments	$(28.4)	$22.7
Cash interest expense [2]	(68.5)	(51.5)
Asset impairment	33.4	—
Non-cash equity based compensation	2.9	5.5
Deferred income tax benefit	(0.2)	(14.1)
Lower of cost or market inventory adjustment	(44.4)	0.8
Loss from unconsolidated affiliates	18.2	12.7
Loss on sale of unconsolidated affiliates	113.4	—
Amortization of turnaround costs	17.4	12.7
Income tax (expense) benefit	(0.5)	13.9
Provision for doubtful accounts	0.5	0.2
Debt extinguishment costs	—	(37.5)
Changes in assets and liabilities:		
Accounts receivable	(60.0)	39.4
Inventories	(10.3)	(40.6)
Other current assets	(1.5)	4.5
Turnaround costs	(8.1)	(5.9)
Derivative activity	(10.4)	(3.5)
Other assets	(0.4)	—
Accounts payable	35.1	(7.0)
Accrued interest payable	9.1	(5.1)
Other current liabilities	9.7	24.6
Other, including changes in noncurrent liabilities	0.7	3.4
Net cash provided by (used in) operating activities	$(51.7)	$160.0

(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, 2016 and 2015

Sales. Sales decreased $183.3 million, or 15.9%, to $972.9 million in the three months ended June 30, 2016 from $1,156.2 million in the same period in 2015. Sales for each of our principal product categories in these periods were as follows:

	Three Months Ended June 30,		
	2016	2015	% Change
	(Dollars in millions, except barrel and per barrel data)		
Sales by segment:			
Specialty products:			
Lubricating oils	$ 146.3	$ 158.1	(7.5)%
Solvents	61.1	81.6	(25.1)%
Waxes	36.3	33.9	7.1 %
Packaged and synthetic specialty products (1)	76.6	88.4	(13.3)%
Other (2)	12.1	8.6	40.7 %
Total specialty products	$ 332.4	$ 370.6	(10.3)%
Total specialty products sales volume (in barrels)	2,760,000	2,388,000	15.6 %
Average specialty products sales price per barrel	$ 120.43	$ 155.19	(22.4)%
Fuel products:			
Gasoline	$ 228.0	$ 283.3	(19.5)%
Diesel	223.5	211.2	5.8 %
Jet fuel	25.8	33.9	(23.9)%
Asphalt, heavy fuel oils and other (3)	126.8	123.6	2.6 %
Hedging activities	15.1	63.1	(76.1)%
Total fuel products	$ 619.2	$ 715.1	(13.4)%
Total fuel products sales volume (in barrels)	11,280,000	8,936,000	26.2 %
Average fuel products sales price per barrel (excluding hedging activities)	$ 53.55	$ 72.96	(26.6)%
Average fuel products sales price per barrel (including hedging activities)	$ 54.89	$ 80.02	(31.4)%
Total oilfield services	$ 21.3	$ 70.5	(69.8)%
Total sales	$ 972.9	$ 1,156.2	(15.9)%
Total specialty and fuel products sales volume (in barrels)	14,040,000	11,324,000	24.0 %

(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.

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The components of the $38.2 million decrease in specialty products segment sales for the three months ended June 30, 2016, as compared to the three months ended June 30, 2015, were as follows:

	Dollar Change (In millions)
Sales price	$ (96.9)
Volume	58.7
Total specialty products segment sales decrease	$ (38.2)

Specialty products segment sales decreased $38.2 million period over period, or 10.3%, primarily due to a decrease in the average selling price per barrel, partially offset by higher sales volume. Sales decreased $96.9 million compared to the second quarter 2015 due to a 22.4% decrease in the average selling price per barrel primarily as a result of lower lubricating oils, solvents and packaged and synthetic specialty products average selling prices due to market conditions, while the average cost of crude oil per barrel decreased 18.6%. Sales volume increased 15.6% as compared to the same period in 2015, resulting in a $58.7 million increase in sales. The increase in sales volume is due primarily to higher sales volume of lubricating oils, solvents and waxes, partially offset by lower sales volumes of packaged and synthetic specialty products.

The components of the $95.9 million decrease in fuel products segment sales for the three months ended June 30, 2016, as compared to the three months ended June 30, 2015, were as follows:

	Dollar Change (In millions)
Sales price	$ (219.1)
Hedging activities	(48.0)
Volume	171.2
Total fuel products segment sales decrease	$ (95.9)

Fuel products segment sales decreased $95.9 million period over period, or 13.4%, primarily due to a decrease in the average selling price per barrel and a $48.0 million decrease in realized derivative gains recorded in sales on our fuel products cash flow hedges, partially offset by increased sales volume. The average selling price per barrel (excluding the impact of hedging activities reflected in sales) decreased $19.41, or 26.6%, resulting in a $219.1 million decrease in sales, compared to a 24.0% decrease in the average cost of crude oil per barrel. The decrease in the average selling price per barrel is primarily due to market conditions. Sales volume increased 26.2% primarily due to increased sales volume of gasoline, diesel and asphalt, primarily as a result of the Great Falls refinery expansion completed in 2016 and market conditions.

Oilfield services segment sales decreased $49.2 million period over period, or 69.8%, primarily due to lower sales volume driven by a decline in rig count. Our rig count decreased 58.5% primarily as a result of a 53.5% decrease in the U.S. land-based rig count. Currently, we sell to approximately 10% of the U.S. land-based rigs. Volatility in crude oil and natural gas prices impacted our customers’ drilling and production activities during 2016, which have resulted in an unfavorable impact on our sales in 2016. Although significant cost reduction efforts have taken effect within the segment, customer activity was well below prior-year levels during the second quarter 2016, resulting in lower net sales during the period.

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Gross Profit. Gross profit decreased $71.4 million, or 35.2%, to $131.3 million in the three months ended June 30, 2016, from $202.7 million in the same period in 2015. Gross profit for our specialty products, fuel products and oilfield services segments were as follows:

	Three Months Ended June 30,		
	2016	2015	% Change
	(Dollars in millions, except per barrel data)		
Gross profit by segment:			
Specialty products:			
Gross profit	$ 98.5	$ 109.7	(10.2)%
Percentage of sales	29.6 %	29.6 %	
Specialty products gross profit per barrel	$ 35.69	$ 45.94	(22.3)%
Fuel products:			
Gross profit excluding hedging activities	$ 29.2	$ 78.9	(63.0)%
Hedging activities	2.8	9.9	(71.7)%
Gross profit	$ 32.0	$ 88.8	(64.0)%
Percentage of sales	5.2 %	12.4 %	
Fuel products gross profit per barrel (excluding hedging activities)	$ 2.59	$ 8.83	(70.7)%
Fuel products gross profit per barrel (including hedging activities)	$ 2.84	$ 9.94	(71.4)%
Oilfield services:			
Gross profit	$ 0.8	$ 4.2	(81.0)%
Percentage of sales	3.8 %	6.0 %	
Total gross profit	$ 131.3	$ 202.7	(35.2)%
Percentage of sales	13.5 %	17.5 %	

The components of the $11.2 million decrease in specialty products segment gross profit for the three months ended June 30, 2016, as compared to the three months ended June 30, 2015, were as follows:

	Dollar Change (In millions)
Three months ended June 30, 2015 reported gross profit	$ 109.7
Sales price	(96.9)
Cost of materials	51.8
Volume	25.1
LCM inventory adjustment	7.2
Operating costs	1.6
Three months ended June 30, 2016 reported gross profit	$ 98.5

The decrease in specialty products segment gross profit of $11.2 million for the three months ended June 30, 2016 compared to the same period in 2015, was due primarily to a decrease in the average selling price per barrel, partially offset by decreased cost of materials, increased sales volume, a $7.2 million increase in the favorable LCM inventory adjustment and a $1.6 million decrease in operating costs. Sales price and cost of materials, net, lowered gross profit by $45.1 million, as the average selling price per barrel decreased 22.4%, while the average cost of crude oil per barrel decreased 18.6%.

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The components of the $56.8 million decrease in fuel products segment gross profit for the three months ended June 30, 2016, as compared to the three months ended June 30, 2015, were as follows:

	Dollar Change (In millions)
Three months ended June 30, 2015 reported gross profit	$ 88.8
Sales price	(219.1)
RINs expense	(17.8)
Hedging activities	(7.1)
Operating costs	(7.1)
Cost of materials	153.8
Volume	38.8
LCM inventory adjustment	1.7
Three months ended June 30, 2016 reported gross profit	$ 32.0

The decrease in fuel products segment gross profit of $56.8 million for the three months ended June 30, 2016 compared to the same period in 2015 was due primarily to narrowing crack spreads, a $17.8 million increase in RINs expense, a $7.1 million decrease in realized gains on derivatives and a $7.1 million increase in operating costs, partially offset by increased sales volume and a $1.7 million increase in the favorable LCM inventory adjustment. During the 2016 period, crack spreads narrowed as the average cost of crude oil per barrel decreased 24.0% and the average selling price per barrel decreased by 26.6%. The $17.8 million increase in RINs expense primarily resulted from increased production and increased RINs market pricing, partially offset by a reduction of the RINs liability as result of an approval from the EPA of a one-year extension of the small refinery exemption from the requirements of the RFS for certain of our refineries for the 2014 calendar year. The increase in operating cost was due primarily to increased depreciation and amortization, partially offset by lower repairs and maintenance.

The decrease in oilfield services segment gross profit of $3.4 million for the three months ended June 30, 2016 compared to the same period in 2015 was due primarily to decreased sales volume driven by a decline in rig count, partially offset by a $15.0 million decrease in the unfavorable LCM inventory adjustment. Volatility in crude oil and natural gas prices resulted in significant reduction in our customers’ drilling and production activities, which had an unfavorable impact on our gross profit in 2016. In addition, the continued decrease in crude oil prices created pricing pressure in the basins in which we operate.

Selling. Selling expenses decreased $11.6 million, or 30.7%, to $26.2 million in the three months ended June 30, 2016, from $37.8 million in the same period in 2015. The decrease was due primarily to a $5.1 million decrease in salaries and benefits primarily as a result of workforce reductions related to the oilfield services segment, a $1.6 million decrease in professional fees expense, a $2.8 million decrease in advertising expense and a $2.2 million decrease in depreciation and amortization.

General and administrative. General and administrative expenses decreased $6.9 million, or 21.8%, to $24.8 million in the three months ended June 30, 2016, from $31.7 million in the same period in 2015. The decrease was due primarily to a $6.1 million decrease in incentive compensation costs, a $1.8 million decrease in professional fees expense and a $0.7 million decrease in severance expense, partially offset by a $1.7 million increase in salaries and benefits.

Transportation. Transportation expenses increased $2.7 million, or 6.4%, to $45.0 million in the three months ended June 30, 2016, from $42.3 million in the same period in 2015. This increase was due primarily to increased sales of lubricating oils and waxes, partially offset by decreased drilling and production activities by our customers in the oilfield services segment and decreased freight rates.

Interest expense. Interest expense increased $15.4 million, or 56.2%, to $42.8 million in the three months ended June 30, 2016, from $27.4 million in the same period in 2015, due primarily 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.

Debt extinguishment costs. Debt extinguishment costs were $46.6 million in the three months ended June 30, 2015. Debt extinguishment costs were due primarily to the redemption of the 9.625% senior notes due August 1, 2020 ("2020 Notes") with a portion of the net proceeds from the issuance of the 2023 Notes in the 2015 period, with no comparable activity in the same period in 2016.

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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, 2016 and 2015:

	Three Months Ended June 30,	
	2016	2015
	(In millions)	
Derivative gain reflected in sales	$15.1	$63.1
Derivative loss reflected in cost of sales	(12.8)	(51.6)
Derivative gain reflected in gross profit	$2.3	$11.5
Realized loss on derivative instruments	$(6.0)	$(14.0)
Unrealized gain on derivative instruments	23.8	5.2
Derivative gain reflected in interest expense	0.1	0.1
Total derivative gain reflected in the unaudited condensed consolidated statements of operations	$20.2	$2.8
Total loss on commodity derivative settlements	$(6.0)	$(15.1)

Realized loss on derivative instruments. Realized loss on derivative instruments decreased $8.0 million to $6.0 million in the three months ended June 30, 2016, from $14.0 million in the prior year period. The change was due primarily to decreased realized losses of approximately $9.3 million related to settlements of derivative instruments used to economically hedge crack spreads and crude oil that are not classified as hedges for accounting purposes and a $0.3 million decrease in premiums paid for crude oil option contracts, partially offset by increased realized losses of approximately $1.7 million on natural gas swaps used to economically hedge natural gas purchases.

Unrealized gain on derivative instruments. Unrealized gain on derivative instruments increased $18.6 million to $23.8 million in the three months ended June 30, 2016, from $5.2 million in the prior year period. The change is due primarily to increased unrealized gains of approximately $18.5 million related to derivative instruments used to economically hedge crack spreads, crude oil and natural gas that are not accounted for as hedges for accounting purposes.

Loss from unconsolidated affiliates. Loss from unconsolidated affiliates decreased $1.1 million to $7.1 million in the three months ended June 30, 2016, from $8.2 million in the same period in 2015, due primarily to unfavorable operating results of Dakota Prairie which reached mechanical completion in April 2015 and commenced sales to third parties in May 2015. Dakota Prairie's lower operating results were driven by narrowing crude oil price differentials and reduced diesel demand as a result of decreased oilfield activity.

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 due primarily to the $113.9 million loss on sale of our Dakota Prairie joint venture in June 2016.

Income tax expense (benefit). Income tax expense (benefit) decreased $9.4 million to an expense of $0.3 million in the three months ended June 30, 2016, from a benefit of $9.1 million in the prior year period. The change was due primarily to the conversion of ADF Holdings, Inc. to ADF Holdings, LLC and Anchor Drilling Fluids USA, Inc. to Anchor Drilling Fluids USA, LLC in 2015, which decreased the proportion of losses subject to federal, state and local income taxes.

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Changes in Results of Operations for the Six Months Ended June 30, 2016 and 2015

Sales. Sales decreased $488.9 million, or 22.5%, to $1,685.9 million in the six months ended June 30, 2016, from $2,174.8 million in the same period in 2015. Sales for each of our principal product categories in these periods were as follows:

	Six Months Ended June 30,		
	2016	2015	% Change
	(Dollars in millions, except barrel and per barrel data)		
Sales by segment:			
Specialty products:			
Lubricating oils	$ 275.5	$ 307.9	(10.5)%
Solvents	117.0	167.8	(30.3)%
Waxes	63.5	72.9	(12.9)%
Packaged and synthetic specialty products (1)	157.5	168.9	(6.7)%
Other (2)	19.6	14.7	33.3 %
Total specialty products	$ 633.1	$ 732.2	(13.5)%
Total specialty products sales volume (in barrels)	5,120,000	4,736,000	8.1 %
Average specialty products sales price per barrel	$ 123.65	$ 154.60	(20.0)%
Fuel products:			
Gasoline	$ 390.2	$ 515.6	(24.3)%
Diesel	346.4	420.3	(17.6)%
Jet fuel	49.2	70.7	(30.4)%
Asphalt, heavy fuel oils and other (3)	182.2	193.5	(5.8)%
Hedging activities	31.1	83.3	62.7 %
Total fuel products	$ 999.1	$ 1,283.4	(22.2)%
Total fuel products sales volume (in barrels)	20,244,000	17,518,000	15.6 %
Average fuel products sales price per barrel (excluding hedging activities)	$ 47.82	$ 68.51	(30.2)%
Average fuel products sales price per barrel (including hedging activities)	$ 49.35	$ 73.26	(32.6)%
Total oilfield services	$ 53.7	$ 159.2	(66.3)%
Total sales	$ 1,685.9	$ 2,174.8	(22.5)%
Total specialty and fuel products sales volume (in barrels)	25,364,000	22,254,000	14.0 %

(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.

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The components of the $99.1 million decrease in specialty products segment sales for the six months ended June 30, 2016, as compared to the six months ended June 30, 2015, were as follows:

	Dollar Change (In millions)
Sales price	$ (159.4)
Volume	60.3
Total specialty products segment sales decrease	$ (99.1)

Specialty products segment sales decreased $99.1 million period over period, or 13.5%, primarily due to a decrease in the average selling price per barrel, partially offset by higher sales volume. Sales decreased $159.4 million compared to the 2015 period due to a 20.0% decrease in the average selling price per barrel, primarily as a result of decreased lubricating oils and solvents average selling prices due to market conditions, while the average cost of crude oil per barrel decreased 23.6%. The increase in sales volume is due primarily to higher sales volume of lubricating oils, partially offset by decreased sales volume of solvents, waxes and packaged and synthetic specialty products due to market conditions.

The components of the $284.3 million decrease in fuel products segment sales for the six months ended June 30, 2016, as compared to the six months ended June 30, 2015, were as follows:

	Dollar Change (In millions)
Sales price	$ (419.0)
Hedging activities	(52.2)
Volume	186.9
Total fuel products segment sales decrease	$ (284.3)

Fuel products segment sales decreased $284.3 million period over period, or 22.2%, primarily due to a decrease in the average selling price per barrel and a $52.2 million decrease in realized derivative gains recorded in sales on our fuel products cash flow hedges, partially offset by increased sales volume. The average selling price per barrel (excluding the impact of hedging activities reflected in sales) decreased $20.69, or 30.2%, resulting in a $419.0 million decrease in sales, compared to a 28.3% decrease in the average cost of crude oil per barrel. The decrease in the average selling price per barrel is primarily due to market conditions. Sales volume increased 15.6% primarily due to increased sales volume of diesel and asphalt as a result of the Great Falls refinery expansion project completed in 2016.

Oilfield services segment sales decreased $105.5 million period over period, or 66.3%, primarily due to decreased sales volume driven by a decline in rig count. Our rig count decreased 58.8% consistent with a 58.1% decrease in the U.S. land-based rig count. Currently, we sell to approximately 10% of the U.S. land-based rigs. Volatility in crude oil and natural gas prices impacted our customers’ drilling and production activities during 2016, which have resulted in an unfavorable impact on our sales in 2016.

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Gross Profit. Gross profit decreased $180.4 million, or 45.3%, to $217.5 million in the six months ended June 30, 2016, from $397.9 million in the same period in 2015. Gross profit for our specialty, fuel products and oilfield services segments were as follows:

	Six Months Ended June 30,		
	2016	2015	% Change
	(Dollars in millions, except per barrel data)		
Gross profit by segment:			
Specialty products:			
Gross profit	$ 197.8	$ 214.2	(7.7)%
Percentage of sales	31.2 %	29.3 %	
Specialty products gross profit per barrel	$ 38.63	$ 45.23	(14.6)%
Fuel products:			
Gross profit (loss) excluding hedging activities	$ 7.4	$ 144.1	(94.9)%
Hedging activities	5.6	8.6	34.9 %
Gross profit (loss)	$ 13.0	$ 152.7	(91.5)%
Percentage of sales	1.3 %	11.9 %	
Fuel products gross profit (loss) per barrel (excluding hedging activities)	$ 0.37	$ 8.23	(95.5)%
Fuel products gross profit (loss) per barrel (including hedging activities)	$ 0.64	$ 8.72	(92.7)%
Oilfield services:			
Gross profit	$ 6.7	$ 31.0	(78.4)%
Percentage of sales	12.5 %	19.5 %	
Total gross profit	$ 217.5	$ 397.9	(45.3)%
Percentage of sales	12.9 %	18.3 %	

The components of the $16.4 million decrease in specialty products segment gross profit for the six months ended June 30, 2016, as compared to the six months ended June 30, 2015, were as follows:

	Dollar Change (In millions)
Six months ended June 30, 2015 reported gross profit	$ 214.2
Sales price	(159.4)
Operating costs	(4.5)
Cost of materials	89.4
LCM inventory adjustment	32.6
Volume	25.5
Six months ended June 30, 2016 reported gross profit	$ 197.8

The decrease in specialty products segment gross profit of $16.4 million for the six months ended June 30, 2016 compared to the same period in 2015 was due primarily to a decrease in the average selling price per barrel and a $4.5 million increase in operating costs, partially offset by decreased cost of materials, a $32.6 million decrease in the unfavorable LCM inventory adjustment primarily as a result of decreased inventory levels and increased sales volume. Sales price and cost of materials, net, lowered gross profit by $70.0 million, as the average selling price per barrel decreased 20.0%, while the average cost of crude oil per barrel decreased 23.6%. The increase in operating costs was due primarily to increased depreciation expense and repairs and maintenance expense, partially offset by decreased natural gas costs.

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The components of the $139.7 million decrease in fuel products segment gross profit for the six months ended June 30, 2016, as compared to the six months ended June 30, 2015, were as follows:

	Dollar Change (In millions)
Six months ended June 30, 2015 reported gross profit	$ 152.7
Sales price	(419.0)
RINs expense	(27.3)
Operating costs	(19.2)
Hedging activities	(3.0)
LCM inventory adjustment	(2.8)
Cost of materials	285.3
Volume	46.3
Six months ended June 30, 2016 reported gross profit	$ 13.0

The decrease in fuel products segment gross profit of $139.7 million for the six months ended June 30, 2016 compared to the same period in 2015 was due primarily to narrowing crack spreads, a $27.3 million increase in RINs expense, a $19.2 million increase in operating costs, a $3.0 million decrease in realized gains on derivative instruments and a $2.8 million decrease in the favorable LCM inventory adjustment, partially offset by increased sales volume. During the 2016 period, crack spreads narrowed as the average cost of crude oil per barrel decreased 28.3% and the average selling price per barrel decreased by 30.2%. The $27.3 million increase in RINs expense primarily resulted from increased production and increased RINs market pricing, partially offset by a reduction of the RINs liability as result of an approval from the EPA of a one-year extension of the small refinery exemption from the requirements of the RFS for certain of our refineries for the 2014 calendar year. The increase in operating costs was due primarily to increased depreciation expense, amortization expense and repairs and maintenance expense, partially offset by decreased natural gas costs.

The decrease in oilfield services segment gross profit of $24.3 million for the six months ended June 30, 2016 compared to the same period in 2015 was due primarily to decreased sales volume driven by a decline in rig count, partially offset by a $15.4 million decrease in the unfavorable LCM inventory adjustment. Volatility in crude oil and natural gas prices resulted in significant reduction in our customers' drilling and production activities, which had an unfavorable impact on our gross profit in 2016. The continued decrease in crude oil prices created pricing pressure in the basins in which we operate.

Selling. Selling expenses decreased $19.5 million, or 25.6% to $56.7 million in the six months ended June 30, 2016, from $76.2 million in the same period in 2015. The decrease was due primarily to an $8.6 million decrease in salaries and benefits primarily as a result of workforce reductions in the oilfield services segment, a $4.6 million decrease in professional fees expense, a $3.5 million decrease in depreciation and amortization and a $3.0 million decrease in advertising expense.

General and administrative. General and administrative expenses decreased $18.5 million, or 26.1%, to $52.4 million in the six months ended June 30, 2016, from $70.9 million in the same period in 2015. The decrease was due primarily to an $11.6 million decrease in incentive compensation costs, a $6.3 million legal matters reserve in the 2015 period, a $2.3 million decrease in severance expense and a $1.9 million decrease in professional fees expense, partially offset by a $3.7 million increase in salaries and benefits.

Transportation. Transportation expenses decreased $0.1 million, or 0.1%, to $84.2 million in the six months ended June 30, 2016, from $84.3 million in the same period in 2015. This decrease was due primarily to increased sales of lubricating oils, partially offset by decreased drilling and production activities by our customers in the oilfield services segment and decreased freight rates.

Interest expense. Interest expense increased $18.7 million, or 34.4%, to $73.1 million in the six months ended June 30, 2016, from $54.4 million in the same period in 2015, due primarily 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.

Debt extinguishment costs. Debt extinguishment costs were $46.6 million for the six months ended June 30, 2015. Debt extinguishment costs were due primarily to the redemption of the 2020 Notes with a portion of the net proceeds from the issuance of the 2023 Notes in the 2015 period, with no comparable activity in the same period in 2016.

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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 six months ended June 30, 2016 and 2015:

	Six Months Ended June 30,	
	2016	2015
	(In millions)	
Derivative gain reflected in sales	$31.1	$83.3
Derivative loss reflected in cost of sales	(26.7)	(73.5)
Derivative gain reflected in gross profit	$4.4	$9.8
Realized loss on derivative instruments	$(18.3)	$(5.1)
Unrealized gain (loss) on derivative instruments	28.4	(22.7)
Derivative gain reflected in interest expense	0.2	0.3
Total derivative gain (loss) reflected in the unaudited condensed consolidated statements of operations	$14.7	$(17.7)
Total loss on commodity derivative settlements	$(18.3)	$(1.8)

Realized loss on derivative instruments. Realized loss on derivative instruments increased $13.2 million to $18.3 million in the six months ended June 30, 2016, from $5.1 million in the prior year period. The change was due primarily to increased realized losses of approximately $9.9 million related to settlements of derivative instruments used to economically hedge crack spreads and crude oil that are not classified as hedges for accounting purposes, increased realized losses of approximately $3.8 million on natural gas swaps used to economically hedge natural gas purchases and decreased gain ineffectiveness of approximately $0.7 million, partially offset by a $1.1 million decrease in premiums paid for crude oil option contracts.

Unrealized gain (loss) on derivative instruments. Unrealized gain (loss) on derivative instruments increased $51.1 million to a gain of $28.4 million in the six months ended June 30, 2016, from a loss of $22.7 million in the prior year period. The change is due primarily to decreased unrealized losses of approximately $50.6 million related to derivative instruments used to economically hedge crack spreads, crude oil and natural gas that are not accounted for as hedges for accounting purposes.

Loss from unconsolidated affiliates. Loss from unconsolidated affiliates increased $5.5 million to $18.2 million in the six months ended June 30, 2016, from $12.7 million in the same period in 2015, due primarily to unfavorable operating results of Dakota Prairie which reached mechanical completion in April 2015 and commenced sales to third parties in May 2015. Dakota Prairie's lower operating results were driven by narrowing crude oil price differentials and reduced diesel demand as a result of decreased oilfield activity.

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 due primarily to the $113.9 million loss on sale of our Dakota Prairie joint venture in June 2016.

Income tax expense (benefit). Income tax expense (benefit) decreased $14.4 million to an expense of $0.5 million in the six months ended June 30, 2016, from a benefit of $13.9 million in the prior year period. The change was due primarily to the conversion of ADF Holdings, Inc. to ADF Holdings, LLC and Anchor Drilling Fluids USA, Inc. to Anchor Drilling Fluids USA, LLC in 2015, which decreased the proportion of losses subject to federal, state and local income taxes.

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 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.

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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 2015 Annual Report. There have been no material changes in that information other than as discussed below. Also, see Note 7 — “Long-Term Debt” and Note 4— “Investment in Unconsolidated Affiliates” under Part I, Item 1 “Financial Statements — Notes to Unaudited Condensed Consolidated Financial Statements” in this Quarterly Report for additional discussion related to our long-term debt and our investment in the Dakota Prairie joint venture.

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.

On April 20, 2016, we issued $400.0 million aggregate principal amount of our 2021 Secured Notes. We used the proceeds of the 2021 Secured Notes to repay borrowings outstanding under our revolving credit facility and for general partnership purposes, including planned capital expenditures at our facilities and working capital.

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 cash flow from operations, borrowings under our revolving credit facility and asset sales. We also expect that the suspension of our quarterly distribution to unitholders will allow us to use cash flow from operations to fund our growth projects in 2016.

We may also from time to time seek to retire or purchase our outstanding debt through cash purchases and/or exchanges for equity securities, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

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 are recorded in unrealized gain (loss) until settlement and 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,	
	2016	2015
	(In millions)	
Net cash provided by (used in) operating activities	$(51.7)	$160.0
Net cash used in investing activities	(98.8)	(199.0)
Net cash provided by financing activities	177.1	42.2
Net increase in cash and cash equivalents	$26.6	$3.2

Operating Activities. Operating activities used cash of $51.7 million during the six months ended June 30, 2016, compared to providing cash of $160.0 million during the same period in 2015. The change is due primarily to decreased net income of $241.9 million, an increase in non-cash charges of $73.8 million and increased working capital requirements in 2016 using $37.7 million compared to 2015 working capital requirements providing $5.9 million. Working capital increases were primarily driven by increased accounts receivable due to timing of cash receipts and decreased accrued salaries, wages and benefits, partially offset by increased accounts payable and decreased inventory volumes as a result of the draw down of asphalt winter fill inventories.

Investing Activities. Cash used in investing activities decreased to $98.8 million during the six months ended June 30, 2016, compared to $199.0 million during the prior year period. The decrease is due primarily to a decrease in capital expenditures of $65.3 million due primarily to the completion of several capital improvement projects, proceeds of $29.0 million primarily related to the sale of Dakota Prairie and a decrease in joint venture investments of $4.2 million.

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Financing Activities. Financing activities provided cash of $177.1 million in the six months ended June 30, 2016, compared to $42.2 million during the prior year period. This increase is due primarily to repayments of senior notes of $275.0 million in the 2015 period, increased net proceeds from the private placements of senior notes of $66.2 million and decreased distributions of $52.6 million, partially offset by decreased net proceeds from public offerings of common units (including our general partner's contributions) of $165.0 million, increased payments on the revolving credit facility of $63.2 million and $34.5 million of repayments of a related party note in 2016.

Joint Ventures

On June 27, 2016, we consummated the sale of our 50% equity interest in Dakota Prairie to joint venture partner WBI Energy, Inc. ("WBI"), a wholly owned subsidiary of MDU. Concurrent with the sale of our 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, we received consideration of $28.5 million, which was offset by our repayment of $36.0 million in borrowings under Dakota Prairie's revolving credit facility. In addition, our $39.4 million letter of credit supporting the Dakota Prairie revolving credit facility was terminated. As part of the transaction, MDU and WBI released us from all liabilities arising out of or related to Dakota Prairie. In addition, Tesoro and Dakota Prairie released us from all liabilities arising out of the organization, management and operation of Dakota Prairie, subject to certain limited exceptions. Further, WBI agreed to indemnify us 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, we recorded a loss on sale of unconsolidated affiliate of $113.9 million during the three and six months ended June 30, 2016.

On August 5, 2015, we 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"). We expects to invest $10.0 million in cash and provide a technology license in exchange for an equity interest of approximately 10% in Hi-Speed through our ownership of 23.8% in PACNIL. As of June 30, 2016, we had an investment of $5.9 million in PACNIL, primarily related to the purchase of equity in the Hi-Speed joint venture.

Capital Expenditures

Our property, plant and equipment capital expenditure requirements consist of capital improvement expenditures, replacement capital expenditures and environmental 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,	
	2016	2015
	(In millions)	
Capital improvement expenditures	$40.8	$158.3
Replacement capital expenditures	7.9	11.5
Environmental capital expenditures	3.2	5.8
Turnaround capital expenditures	8.1	5.9
Joint venture contributions, net [(1)]	12.8	46.0
Total	$72.8	$227.5

(1) Includes proceeds from sale of unconsolidated affiliates.

We anticipate that future 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.

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We estimate our replacement and environmental capital expenditures will be approximately $45.0 million to $55.0 million in 2016. These estimated amounts for 2016 include a portion of the $3.0 million to $5.0 million in environmental projects to be spent as required by our settlement with the LDEQ under the "Small Refinery and Single Site Refining Initiative." Please read Note 6 of Part I, Item 1 "Financial Statements — Commitments and Contingencies — Environmental — Occupational Health and Safety" for additional information.
We estimate we will spend approximately $60.0 million to $70.0 million in 2016 on capital improvement projects. In February 2016, we completed an expansion project that increased production capacity at our Great Falls refinery by 15,000 bpd to 25,000 bpd.
We estimate turnaround spending requirements will be $10.0 million to $15.0 million for 2016, primarily related to scheduled turnaround activity at our Shreveport, San Antonio and Princeton refineries. We expect these expenditures will be funded primarily through cash flow from operations. During the six months ended June 30, 2016, we spent approximately $8.1 million primarily related to the scheduled turnaround activities explained above, funded through cash flow from operations and borrowings under our revolving credit facility.
Debt and Credit Facilities
As of June 30, 2016, our primary debt and credit instruments consisted of:
- a $1.0 billion 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");
- $900.0 million of 6.50% senior notes due 2021 ("2021 Notes");
- $350.0 million of 7.625% senior notes due 2022 ("2022 Notes");
- $325.0 million of 7.75% senior notes due 2023 ("2023 Notes");
- $400.0 million of 11.50% senior secured notes due 2021 ("2021 Secured Notes"); and
- $39.9 million related party note payable.

We were in compliance with all covenants under the debt instruments in place as of June 30, 2016, and believe we have adequate liquidity to conduct our business.
Short Term Liquidity
As of June 30, 2016, our principal sources of short-term liquidity were (i) $437.5 million of availability under our revolving credit facility and (ii) $32.2 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, 2016, we had availability on our revolving credit facility of $437.5 million, based on a $502.0 million borrowing base, $64.4 million in outstanding standby letters of credit and $0.1 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 $1.0 billion. The lenders under our revolving credit facility have a first priority lien on our accounts receivable, inventory and substantially all of our cash.
Amounts outstanding under our revolving credit facility 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, 2016, were $299.4 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, 2016, availability for additional borrowings under our revolving credit facility was approximately $82.0 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, 2016, this margin was 75 basis points for prime rate loans and 175 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.

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).

On April 20, 2016, we and certain of our operating subsidiaries as borrowers (collectively, the “Borrowers”) entered into a Second Amendment to Second Amended and Restated Credit Agreement (the “Second Amendment”), by and among the Borrowers, the Second Amendment Agent and the lenders party thereto (including Bank of America, N.A.), amending the revolving credit facility. The Second Amendment, among other things, amends the revolving credit facility to permit (i) the issuance of the 2021 Secured Notes pursuant to the indenture governing the 2021 Secured Notes and (ii) such 2021 Secured Notes to be secured by a lien on the Parity Lien Collateral (as defined in the Second Amendment), subject to the terms of the Intercreditor Agreement (as defined in the Second Amendment).

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, 2016, we had $900.0 million in 2021 Notes, $350.0 million in 2022 Notes, $325.0 million in 2023 Notes and $400.0 million in 2021 Secured Notes outstanding. As of December 31, 2015, we had $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, 2016, our Fixed Charge Coverage Ratio (as defined in the indentures governing the 2021 Secured, 2021, 2022 and 2023 Notes) was 0.8 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, our ability to grow 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 credit ratings, see "Credit Ratings" below.

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 2015 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, 2016. 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.

The fair value of our derivatives that were outstanding as of June 30, 2016, decreased by approximately $18.0 million subsequent to June 30, 2016, to a net liability of approximately $24.0 million. 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.

Credit Ratings

In April 2016, our senior unsecured notes ratings and partnership ratings were downgraded by credit rating agencies. Our senior unsecured notes ratings decreased to Caa2 from B3 and CCC+ from B by Moody's and S&P, respectively. Our partnership rating decreased to Caa1 from B2 and B- from B by Moody's and S&P, respectively. This downgrade in our credit ratings could adversely affect our ability to obtain new financing and increase the costs of our financing and, in turn, adversely affect our financial results.

Equity Transactions

We entered into an Equity Placement Agreement with various sales agents under which we issued and sold, from time to time, common units representing limited partner interests, having an aggregate offering price of up to $300.0

million through one or more sales agents. The Equity Placement Agreement expired in May 2016. The net proceeds from any sales under this agreement were used for general partnership purposes, which included, among other things, repayment of indebtedness, working capital and capital expenditures. Our general partner contributed its proportionate capital contribution to retain its 2% general partner interest. For the three and six months ended June 30, 2016, we had no sales of our common units under the Equity Placement Agreement.

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In April 2016, the Board of Directors of our general partner suspended payment of our quarterly cash distribution. The Board of Directors of our general partner will continue to evaluate our ability to reinstate the distribution. During 2016, we have made the following cash distributions on all outstanding common units (including our general partner's incentive distribution rights) (in millions except per unit data):

Quarter Ended	Declaration Date	Record Date	Distribution Date	Quarterly Distribution per Unit	Aggregate Quarterly Distribution	Annualized Distribution per Unit	Aggregate Annualized Distribution
December 31, 2015	January 19, 2016	February 2, 2016	February 12, 2016	$ 0.685	$ 57.4	$ 2.74	$ 229.6

Contractual Obligations and Commercial Commitments

A summary of our total contractual cash obligations as of June 30, 2016, at current maturities and reflecting only those line items that have materially changed since December 31, 2015, 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)]	$943.6	$155.5	$332.3	$324.8	$131.0
Operating lease obligations [(2)]	163.4	40.6	64.4	34.2	24.2
Letters of credit [(3)]	64.4	64.4	—	—	—
Purchase commitments [(4)]	781.7	539.7	200.4	41.6	—
Employment agreements	5.0	2.8	1.5	0.7	—
Financing activities:					
Capital lease obligations	45.6	1.6	3.0	2.0	39.0
Long-term debt obligations, excluding capital lease obligations	2,015.8	40.7	—	1,300.1	675.0
Total obligations	$4,019.5	$845.3	$601.6	$1,703.4	$869.2

(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 that extend through August 2035.

(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 this minimum supply quantity, we expect to purchase $34.6 million of feedstock for the LVT unit in each fiscal year of the term based on pricing estimates as of June 30, 2016. This amount is not included in the table above.

For additional information regarding our expected capital and turnaround expenditures for the remainder of 2016, for which we have not contractually committed, refer to "Capital Expenditures" above.

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, 2016.

Critical Accounting Policies and Estimates

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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 2015 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 2015 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"), Western Canadian Select ("WCS"), Mixed Sweet Blend ("MSW") and ICE Brent ("Brent").

The following table provides a summary of crude oil swap purchases as of June 30, 2016 in our fuel products segment:

Crude Oil Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Swap ($/Bbl)
Third Quarter 2016	398,894	4,336	$ 39.46
Fourth Quarter 2016	398,894	4,336	$ 39.46
Calendar Year 2017	1,297,977	3,556	$ 48.87
Total	2,095,765		
Average price			$ 45.29

The following table provides a summary of crude oil swap sales as of June 30, 2016 in our fuel products segment:

Crude Oil Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
Calendar Year 2017	528,520	1,448	$ 41.56
Total	528,520		
Average price			$ 41.56

We have entered into crude oil basis swaps to mitigate the risk of future changes in pricing differentials between LLS and NYMEX WTI. The following table provides a summary of crude oil basis swap contracts as of June 30, 2016 in our fuel products segment:

Crude Oil Basis Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Differential to NYMEX WTI ($/Bbl)
Third Quarter 2016	460,000	5,000	$ 1.80
Fourth Quarter 2016	460,000	5,000	$ 1.80
Total	920,000		

Average differential	$ 1.80

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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, 2016 in our fuel products segment:

Crude Oil Basis Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Differential to NYMEX WTI ($/Bbl)
Third Quarter 2016	1,196,000	13,000	$ (13.16)
Fourth Quarter 2016	1,196,000	13,000	$ (13.16)
Calendar Year 2017	2,555,000	7,000	$ (13.22)
Total	4,947,000		
Average differential			$ (13.19)

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, 2016 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 2016	736,000	8,000	73.5 %
Fourth Quarter 2016	736,000	8,000	73.5 %
Calendar Year 2017	1,095,000	3,000	72.3 %
Total	2,567,000		
Average percentage			73.0 %

We have entered into derivative instruments to mitigate the risk of future changes in the price of NYMEX WTI crude oil. The following table provides a summary of crude oil call option purchases as of June 30, 2016 in our fuel products segment:

Crude Oil Option Contracts by Expiration Dates	Barrels Purchased	BPD	Average Bought Call ($/Bbl)
Fourth Quarter 2016	350,000	3,804	$ 55.00
Total	350,000		
Average price			$ 55.00

The following table provides a summary of natural gas swaps as of June 30, 2016 in our fuel products segment:

Natural Gas Swap Contracts by Expiration Dates	MMBtu	$/MMBtu
Third Quarter 2016	606,000	$ 3.03
Fourth Quarter 2016	790,000	$ 3.02
Total	1,396,000	
Average price		$ 3.02

The following table provides a summary of natural gas swaps as of June 30, 2016 in our specialty products segment:

Natural Gas Swap Contracts by Expiration Dates	MMBtu	$/MMBtu
Third Quarter 2016	1,380,000	$ 4.26
Fourth Quarter 2016	1,540,000	$ 4.14

Calendar Year 2017	4,950,000	$ 3.85
Total	7,870,000	
Average price		$ 3.98

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The following table provides a summary of natural gas collars as of June 30, 2016 in our specialty products segment:

Natural Gas Collars by Expiration Dates	MMBtu	Average Bought Call ($/MMBtu)	Average Sold Put ($/MMBtu)
Third Quarter 2016	180,000	$ 4.25	$ 3.89
Fourth Quarter 2016	60,000	$ 4.25	$ 3.89
Total	240,000		
Average price		$ 4.25	$ 3.89

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, 2016:

	In millions
Crude oil swaps	$ 1.6
Crude oil basis swaps	$ 5.9
Crude oil percentage basis swaps	$ 2.6
Crude oil option contracts	$ 0.4
Natural gas swaps	$ 9.3
Natural gas collars	$ 0.2

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, 2016, would be expected to have a negative impact on net income (loss) for 2016 of approximately $122.0 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 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, 2016, and December 31, 2015, 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."

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	June 30, 2016		December 31, 2015	
	Fair Value	Carrying Value	Fair Value	Carrying Value
	(In millions)			
Financial Instrument:				
2021 Notes	$648.0	$ 889.1	$798.3	$ 888.0
2022 Notes	$250.0	$ 343.3	$297.5	$ 342.8
2023 Notes	$230.8	$ 317.9	$294.1	$ 317.6
2021 Secured Notes	$452.0	$ 383.6	$—	$ —

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 $1.0 billion revolving credit facility as of June 30, 2016, 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 $0.1 million and $111.0 million of variable rate debt as of June 30, 2016, and December 31, 2015, 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, 2016, would have an immaterial impact on net income (loss) and cash flows for the 2016 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, 2016, 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 of 2016 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 6 — "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 2015 Annual Report and in Part II, Item 1A "Risk Factors" in our Q1 Quarterly 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 2015 Annual Report or in Part II, Item 1A "Risk Factors" in our Q1 Quarterly Report.

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.

Item 5. Other Information

None.

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)).
4.1	Indenture, dated April 20, 2016, by and among the Issuers, the Guarantors and the Trustee, relating to the offering of the 2021 Secured Notes (incorporated by reference to Exhibit 4.1 to the Registrant’s Current Report on Form 8-K filed with the Commission on April 21, 2016 (File No. 000-51734)).
4.2	Form of 11.5% Senior Secured Note due 2021 (included in Exhibit 4.1 incorporated by reference to Exhibit 4.2 to the Registrant’s Current Report on Form 8-K filed with the Commission on April 21, 2016 (File No. 000-51734)).
10.1	Amended and Restated Collateral Trust Agreement, dated as of April 20, 2016, among the Partnership, the obligors party thereto, the secured hedge counterparties party thereto and Wilmington Trust, National Association, as Trustee and Collateral Trustee (incorporated by reference to Exhibit 10.1 to the Registrant’s Current Report on Form 8-K filed with the Commission on April 21, 2016 (File No. 000-51734)).
10.2	Second Amended and Restated Intercreditor Agreement, dated April 20, 2016, by and among the Collateral Trustee, Bank of America, N.A., as administrative agent, and the obligors named therein (incorporated by reference to Exhibit 10.2 to the Registrant’s Current Report on Form 8-K filed with the Commission on April 21, 2016 (File No. 000-51734)).
10.3	Second Amendment to Second Amended and Restated Credit Agreement, dated as of April 20, 2016, by and among the Partnership and certain of its subsidiaries as Borrowers, certain of its subsidiaries as

	Guarantors, the Lenders, Bank of America, N.A., as Agent, JPMorgan Chase Bank, N.A. and Wells Fargo Bank, N.A., as Co-Syndication Agents, PNC Bank, N.A., as Co-Documentation Agent and Bank of America, N.A., as Issuing Bank (incorporated by reference to Exhibit 10.3 to the Registrant's Current Report on Form 8-K filed with the Commission on April 21, 2016 (File No. 000-51734)).
31.1*	Sarbanes-Oxley Section 302 certification of Timothy Go.
31.2*	Sarbanes-Oxley Section 302 certification of R. Patrick Murray, II.
32.1**	Section 1350 certification of Timothy Go and R. Patrick Murray, II.
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

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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 5, 2016	By:	/s/ R. Patrick Murray, II
		R. Patrick Murray, II Executive Vice President, Chief Financial Officer and Secretary of Calumet GP, LLC (Principal Accounting and Financial Officer) (Authorized Person and Principal Accounting Officer)

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Index to Exhibits

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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)).
4.1	Indenture, dated April 20, 2016, by and among the Issuers, the Guarantors and the Trustee, relating to the offering of the 2021 Secured Notes (incorporated by reference to Exhibit 4.1 to the Registrant’s Current Report on Form 8-K filed with the Commission on April 21, 2016 (File No. 000-51734)).
4.2	Form of 11.5% Senior Secured Note due 2021 (included in Exhibit 4.1 incorporated by reference to Exhibit 4.2 to the Registrant’s Current Report on Form 8-K filed with the Commission on April 21, 2016 (File No. 000-51734)).
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