Calumet Specialty Products Partners, L.P.
Form 10-Q
May 08, 2015
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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 MARCH 31, 2015

OR

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

FOR THE TRANSITION PERIOD FROM TO

Commission File Number: 000-51734

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

Delaware (State or Other Jurisdiction of Incorporation or Organization)	37-1516132 (I.R.S. Employer Identification Number)
2780 Waterfront Parkway East Drive, Suite 200 Indianapolis, Indiana (Address of Principal Executive Officers)	46214 (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 May 8, 2015, there were 75,760,218 common units outstanding.

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CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
QUARTERLY REPORT
For the Three Months Ended March 31, 2015
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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) estimated capital expenditures as a result of our planned organic growth projects and estimated annual EBITDA contributions from such projects, (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, 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, 2014 (“2014 Annual Report”) and (ii) 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 they are made. 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

	March 31, 2015	December 31, 2014
	(Unaudited)	
	(In millions, except unit data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$272.8	$8.5
Accounts receivable:		
Trade	307.3	326.0
Other	13.3	23.8
	320.6	349.8
Inventories	519.2	513.5
Derivative assets	—	23.2
Prepaid expenses and other current assets	3.5	7.5
Deposits	1.0	1.7
Deferred income taxes	1.8	2.3
Total current assets	1,118.9	906.5
Property, plant and equipment, net	1,520.4	1,464.4
Investment in unconsolidated affiliates	157.8	137.3
Goodwill	245.8	245.8
Other intangible assets, net	247.1	257.5
Other noncurrent assets, net	109.6	108.3
Total assets	$3,399.6	$3,119.8
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$348.3	$419.9
Accrued interest payable	38.3	37.6
Accrued salaries, wages and benefits	23.9	21.9
Other taxes payable	15.9	17.9
Other current liabilities	78.1	40.0
Current portion of long-term debt	272.0	0.6
Derivative liabilities	22.3	5.6
Total current liabilities	798.8	543.5
Deferred income taxes	27.0	32.3
Pension and postretirement benefit obligations	19.6	20.0
Other long-term liabilities	1.0	0.9
Long-term debt, less current portion	1,614.1	1,712.9
Total liabilities	2,460.5	2,309.6
Commitments and contingencies		
Partners' capital:		
Limited partners' interest (75,760,218 units and 69,452,233 units, issued and outstanding as of March 31, 2015 and December 31, 2014, respectively)	894.9	765.9
General partner's interest	34.0	30.6
Accumulated other comprehensive income	10.2	13.7

Total partners’ capital	939.1	810.2
Total liabilities and partners’ capital	$3,399.6	$3,119.8

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 March 31,	
	2015	2014
	(In millions, except per unit and unit data)	
Sales	$1,018.6	$1,341.0
Cost of sales	823.4	1,216.2
Gross profit	195.2	124.8
Operating costs and expenses:		
Selling	38.4	19.0
General and administrative	39.2	25.9
Transportation	42.0	40.4
Taxes other than income taxes	4.0	2.1
Other	2.9	2.1
Operating income	68.7	35.3
Other income (expense):		
Interest expense	(27.0)	(26.2)
Debt extinguishment costs	—	(89.6)
Realized gain on derivative instruments	8.9	6.6
Unrealized gain (loss) on derivative instruments	(27.9)	24.6
Other	(3.7)	(0.3)
Total other expense	(49.7)	(84.9)
Net income (loss) before income taxes	19.0	(49.6)
Income tax expense (benefit)	(4.8)	0.2
Net income (loss)	$23.8	$(49.8)
Allocation of net income (loss):		
Net income (loss)	$23.8	$(49.8)
Less:		
General partner's interest in net income (loss)	0.5	(1.0)
General partner's incentive distribution rights	4.2	3.8
Non-vested share based payments	—	—
Net income (loss) available to limited partners	$19.1	$(52.6)
Weighted average limited partner units outstanding:		
Basic	71,232,392	69,622,884
Diluted	71,275,452	69,622,884
Limited partners' interest basic and diluted net income (loss) per unit	$0.27	$(0.76)
Cash distributions declared per limited partner unit	$0.685	$0.685

See accompanying notes to unaudited condensed consolidated financial statements.

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

	Three Months Ended March 31,	
	2015	2014
	(In millions)	
Net income (loss)	$23.8	$(49.8)
Other comprehensive income (loss):		
Cash flow hedges:		
Cash flow hedge loss reclassified to net income (loss)	1.7	3.9
Change in fair value of cash flow hedges	(5.1)	42.4
Defined benefit pension and retiree health benefit plans	0.2	0.2
Foreign currency translation adjustment	(0.3)	0.2
Total other comprehensive income (loss)	(3.5)	46.7
Comprehensive income (loss) attributable to partners’ capital	$20.3	$(3.1)

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 Income	Partners' Capital		
		General Partner	Limited Partners	Total
	(In millions)			
Balance at December 31, 2014	$13.7	$30.6	$765.9	$810.2
Other comprehensive loss	(3.5)	—	—	(3.5)
Net income	—	4.7	19.1	23.8
Common units repurchased for phantom unit grants	—	—	(3.2)	(3.2)
Amortization of vested phantom units	—	—	0.5	0.5
Issuances of phantom units, net of taxes withheld	—	—	(1.3)	(1.3)
Proceeds from public offerings of common units, net	—	—	161.7	161.7
Contributions from Calumet GP, LLC	—	3.5	—	3.5
Distributions to partners	—	(4.8)	(47.8)	(52.6)
Balance at March 31, 2015	$10.2	$34.0	$894.9	$939.1

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

	Three Months Ended March 31,	
	2015	2014
	(In millions)	
Operating activities		
Net income (loss)	$23.8	$(49.8)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization	35.4	30.2
Amortization of turnaround costs	6.1	5.8
Non-cash interest expense	1.4	1.9
Non-cash debt extinguishment costs	—	18.7
Provision for doubtful accounts	—	0.6
Unrealized (gain) loss on derivative instruments	27.9	(24.6)
Non-cash equity based compensation	3.2	3.0
Lower of cost or market inventory adjustment	13.2	(1.3)
Other non-cash activities	1.3	1.1
Changes in assets and liabilities:		
Accounts receivable	29.2	(54.1)
Inventories	(18.9)	(50.0)
Prepaid expenses and other current assets	3.7	2.6
Derivative activity	9.2	1.5
Turnaround costs	(2.7)	(3.0)
Deposits	0.7	3.2
Accounts payable	(78.9)	163.2
Accrued interest payable	0.7	(7.4)
Accrued salaries, wages and benefits	(1.9)	0.3
Other taxes payable	(2.0)	(1.7)
Other liabilities	38.2	(0.6)
Pension and postretirement benefit obligations	(0.2)	—
Net cash provided by operating activities	89.4	39.6
Investing activities		
Additions to property, plant and equipment	(74.1)	(46.3)
Cash paid for acquisitions, net of cash acquired	—	(247.0)
Investment in unconsolidated affiliates	(25.0)	(16.0)
Proceeds from sale of property, plant and equipment	0.1	—
Net cash used in investing activities	(99.0)	(309.3)
Financing activities		
Proceeds from borrowings — revolving credit facility	358.8	6.5
Repayments of borrowings — revolving credit facility	(509.5)	(6.5)
Repayments of borrowings — senior notes	—	(500.0)
Payments on capital lease obligations	(1.7)	(0.3)
Proceeds from senior notes offering	322.6	900.0
Debt issuance costs	(5.6)	(15.9)
Proceeds from public offerings of common units, net	161.7	—
Contributions from Calumet GP, LLC	3.5	—
Common units repurchased and taxes paid for phantom unit grants	(3.2)	(2.1)
Cash settlement of unit based compensation	—	(0.9)
Distributions to partners	(52.7)	(52.6)

Net cash provided by financing activities	273.9	328.2
Net increase in cash and cash equivalents	264.3	58.5
Cash and cash equivalents at beginning of period	8.5	121.1
Cash and cash equivalents at end of period	$272.8	$179.6
Supplemental disclosure of non-cash financing and investing activities		
Non-cash property, plant and equipment additions	$47.2	$16.4

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 March 31, 2015, the Company had 75,760,218 limited partner common units and 1,546,126 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 is also engaged in the resale of purchased crude oil to third party customers. The Company is based in Indianapolis, Indiana and owns specialty and fuel products facilities primarily located in northwest Louisiana, northwest Wisconsin, northern Montana, western Pennsylvania, Texas, New Jersey, eastern Missouri and North Dakota. The Company owns and leases oilfield services locations in Texas, Oklahoma, Louisiana, Arkansas, Colorado, Utah, Wyoming, Montana, New Mexico, New York, North Dakota, Pennsylvania and Ohio. 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 March 31, 2015 and for the three months ended March 31, 2015 and 2014 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 months ended March 31, 2015 are not necessarily indicative of the results that may be expected for the year ending December 31, 2015. These unaudited condensed consolidated financial statements should be read in conjunction with the Company’s 2014 Annual Report.

2. Summary of Significant Accounting Policies

New Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) No. 2014-09, Revenue from Contracts with Customers (Topic 606) (“ASU 2014-09”), which supersedes the revenue recognition requirements in ASC 605, Revenue Recognition. ASU 2014-09 is based on the principle that revenue is recognized to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. 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 is effective for fiscal periods (including interim periods) beginning after December 15, 2016 and early adoption is not permitted. ASU 2014-09 allows for either a full retrospective or a modified retrospective transition method. The Company is currently evaluating the impact of this standard on its condensed consolidated financial statements.

In June 2014, the FASB issued ASU No. 2014-12, Compensation-Stock Compensation (Topic 718): Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved after the Requisite Service Period (“ASU 2014-12”). ASU 2014-12 provides guidance for the recognition, measurement and disclosure of obligations resulting from unit-based payments after the requisite service period has ended when the eligible employee has ceased rendering service and is still eligible to vest in the award if the performance target is achieved. ASU 2014-12 is effective for fiscal periods (including interim periods) beginning after December 15, 2015 and early adoption is permitted. Provisions of ASU 2014-12 may be applied either prospectively to all awards granted or modified after the effective date or retrospectively to all awards with performance targets that are outstanding as of the beginning of the earliest annual period presented in the financial statements and to all new or modified awards thereafter. The adoption of ASU 2014-12 is not expected to have an impact on the Company’s consolidated financial statements as its unit-based compensation plans do not currently provide for achieving performance targets subsequent to the end of requisite service periods.

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In August 2014, the FASB issued ASU No. 2014-15, Presentation of Financial Statements - Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern ("ASU 2014-15"). ASU 2014-15 provides guidance about management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and to provide related footnote disclosures. ASU 2014-15 is effective for fiscal periods (including interim periods) ending after December 15, 2016, and early adoption is permitted. The adoption of ASU 2014-15 is not expected to have an impact on the Company's condensed consolidated financial statements.

In February 2015, the FASB issued ASU No. 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis ("ASU 2015-02"). ASU 2015-02 amends the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. ASU 2015-02 is effective for fiscal periods (including interim periods) beginning after December 15, 2015 and early adoption is permitted. The adoption of ASU 2015-02 is not expected to have an impact on the Company's condensed consolidated financial statements.

In April 2015, the FASB issued ASU No. 2015-03, Interest - Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs ("ASU 2015-03"). ASU 2015-03 requires debt issuance costs to be recognized in the balance sheet as a direct deduction from the related debt liability rather than as an asset. ASU 2015-03 also requires the amortization of debt issuance costs to be reported as interest expense. ASU 2015-03 is effective for fiscal periods (including interim periods) beginning after December 15, 2015 and early adoption is permitted. ASU 2015-03 must be applied retrospectively, where the balance sheet of each presented individual period is adjusted to indicate the period-specific impact of using the new guidance. The Company has not yet adopted ASU 2015-03, but the impact of adopting would result in the Company reclassifying approximately $39.1 million and $34.7 million, as of March 31, 2015 and December 31, 2014, respectively, of deferred debt issuance costs from other noncurrent assets to long-term debt in the condensed consolidated balance sheets.

In April 2015, the FASB issued ASU No. 2015-04, Compensation - Retirement Benefits (Topic 715): Practical Expedient for the Measurement Date of an Employer's Defined Benefit Obligation and Plan Assets ("ASU 2015-04"). ASU 2015-04 provides guidance for the measuring of assets in defined benefit pension plans and other retirement plans if they are on fiscal years that do not end on the last day of a month. ASU 2015-04 is effective for fiscal periods (including interim periods) beginning after December 15, 2015 and early adoption is permitted. The Company is currently evaluating the impact of this standard on its condensed consolidated financial statements.

In April 2015, the FASB issued ASU No. 2015-05, Intangibles - Goodwill and Other - Internal-Use Software (Subtopic 350-40): Customer's Accounting for Fees Paid in a Cloud Computing Arrangement ("ASU 2015-05"). ASU 2015-05 provides guidance to determine whether a cloud computing agreement includes a software license or should be considered as a service agreement. ASU 2015-05 is effective for fiscal periods (including interim periods) beginning after December 15, 2015 and early adoption is permitted. An entity can elect to adopt the amendments either (1) prospectively to all arrangements entered into or materially modified after the effective date or (2) retrospectively. The Company is currently evaluating the impact of this standard on its condensed consolidated financial statements.

3. Acquisitions

On August 1, 2014, the Company completed the acquisition of substantially all of the assets of privately-held Specialty Oilfield Solutions, Ltd. ("SOS") for aggregate consideration of approximately $29.6 million, net of cash acquired ("SOS Acquisition"). SOS is a full-service drilling fluids and solids control company with operations in the Eagle Ford, Marcellus and Utica shale formations. The SOS Acquisition was financed with borrowings under the Company's revolving credit facility. The Company believes the SOS Acquisition increases its sales into the oilfield services market, expands its geographic reach and increases its asset diversity.

On March 31, 2014, the Company completed the acquisition of 100% of the membership interests of ADF Holdings, Inc., the parent company of Anchor Drilling Fluids USA, Inc. ("Anchor"), an independent provider and marketer of drilling fluids, completion fluids and production chemicals to the oil and gas exploration industry ("Anchor Acquisition"). Total consideration was approximately $223.6 million, net of cash acquired. In connection with the Anchor Acquisition, the Company is required to pay the sellers 50% of the amount of taxes paid in a post-closing tax period that are reduced (or a refund is actually received or credited) as a result of the utilization of post-closing transaction tax deductions in the 2014 taxable year (but, for the avoidance of doubt, no other taxable year), which is estimated to be $1.0 million as of March 31, 2015. Anchor designs, manufactures and packages drilling fluid products at its locations in Texas, Oklahoma, Louisiana, Arkansas, Colorado, Utah, Wyoming, Montana, New Mexico, New York, North Dakota, Pennsylvania and Ohio. The Anchor Acquisition was financed by using a portion of the net proceeds of approximately $884.0 million from the Company's March 2014 private placement of 6.50% senior notes due April 15, 2021. The Company believes the Anchor Acquisition further expands its specialty products offering, increases its sales into the oilfield services market, expands its geographic reach and increases its asset diversity.

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On February 28, 2014, the Company completed the acquisition of substantially all of the assets of United Petroleum, LLC ("United Petroleum"), a marketer and distributor of high performance lubricants, for aggregate consideration of approximately $10.4 million, ("United Petroleum Acquisition"). The United Petroleum Acquisition was financed with cash on hand. The Company believes the United Petroleum Acquisition increases its position in the specialty lubricants market.

There have been no changes to the purchase price allocation, goodwill or intangible assets for the SOS, Anchor and United Petroleum Acquisitions since December 31, 2014.

Results of Sales and Earnings

The following financial information reflects sales and operating loss of the Anchor Acquisition included in the unaudited condensed consolidated statements of operations for the three months ended March 31, 2015 (in millions):

	Three Months Ended March 31, 2015
Sales	$83.9
Operating loss	$(6.8)

Unaudited Pro Forma Financial Information

The following unaudited pro forma financial information reflects the unaudited condensed consolidated results of operations of the Company as if the Anchor Acquisition had taken place on January 1, 2014 (in millions, except for per unit data):

	Three Months Ended March 31, 2014
Sales	$1,423.5
Net loss	$(62.2)
Limited partners' interest net loss per unit — basic and diluted	$(0.93)

The Company's historical financial information was adjusted to give effect to the pro forma events that were directly attributable to the Anchor Acquisition. This unaudited pro forma financial information has been presented for illustrative purposes only and is not necessarily indicative of results of operations that would have been achieved had the pro forma events taken place on the dates indicated, or the future consolidated results of operations of the combined company.

4. 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 $71.5 million and $18.9 million lower as of March 31, 2015 and December 31, 2014, respectively.

Inventories consist of the following (in millions):

	March 31, 2015	December 31, 2014
Raw materials	$86.7	$77.8
Work in process	77.9	75.4
Finished goods	354.6	360.3
	$519.2	$513.5

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. During the quarter ended March 31, 2015, the Company recorded $13.2 million

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of losses in cost of sales in the condensed consolidated statements of operations due to the lower of cost or market valuation. During the quarter ended March 31, 2014, the Company recorded $1.3 million of gains in cost of sales in the condensed consolidated statements of operations due to the lower of cost or market valuation.

5. Investment in Unconsolidated Affiliates

Dakota Prairie Refining, LLC

On February 7, 2013, the Company entered into a joint venture agreement with MDU Resources Group, Inc. (“MDU”) to develop, build and operate a diesel refinery in southwestern North Dakota. The joint venture is named Dakota Prairie Refining, LLC (“Dakota Prairie”). The capitalization of the joint venture is expected to be funded through contributions of $217.5 million from MDU and a total of $217.5 million from the Company comprised of $142.5 million through cash contributions and proceeds of $75.0 million from an unsecured syndicated term loan facility with the joint venture as the borrower which is expected to be repaid by the Company through its allocation of profits from the joint venture. The term loan facility was funded in April 2013. The joint venture allocates profits on a 50%/50% basis to the Company and MDU. The joint venture is governed by a board of managers comprised of representatives from both the Company and MDU. MDU is providing a portion of the crude oil supply to the refinery, as well as natural gas and electricity utility services. The Company is providing refinery operations, crude oil procurement and refined product marketing expertise to the joint venture. Dakota Prairie reached mechanical completion and was commissioned in April 2015. Dakota Prairie is expected to commence sales of finished products in May 2015.

The Company accounts for its ownership in the Dakota Prairie joint venture under the equity method of accounting. As of March 31, 2015 and December 31, 2014, the Company had an investment of $133.3 million and $117.2 million, respectively, in Dakota Prairie, primarily related to the development of the refinery.

Juniper GTL LLC

On June 9, 2014, the Company entered into a joint venture agreement with Clean Fuels North America, LLC, which is owned by SGC Energia and Great Northern Project Development, to develop, build and operate a gas-to-liquids (“GTL”) plant in Lake Charles, Louisiana, which is expected to be operational by mid-2016. The joint venture is named New Source Fuels, LLC, and it owns 100% of Juniper GTL LLC (“Juniper”). The capitalization of the joint venture is expected to be funded through $100.0 million of equity contributions and $35.0 million in senior secured debt with the joint venture as the borrower. The Company intends to invest $25.0 million in total in exchange for an equity interest of approximately 23% in the joint venture. Funding of the project will occur over the course of the construction period. The joint venture is governed by a board of managers comprised of representatives from all of the members that own at least 10% of the equity in Juniper.

The Company accounts for its ownership in the Juniper joint venture under the equity method of accounting. As of March 31, 2015 and December 31, 2014, the Company had an investment of $23.0 million and $18.5 million, respectively, in Juniper, primarily related to the development of the plant.

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 taxation and regulatory 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 operates crude oil and specialty hydrocarbon refining, blending and terminal operations, which 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. 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 could require the Company to make additional unforeseen expenditures. Many of these laws and regulations are becoming increasingly stringent, and the cost of compliance with these requirements can be expected

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to increase over time. For example, on January 14, 2015, the Obama Administration announced that the EPA is expected to propose in the summer of 2015, and finalize in 2016, new regulations that will set methane emission standards for new and modified oil and gas production and natural gas processing and transmission facilities as part of the Administration's efforts to reduce methane emissions from the oil and gas sector by up to 45% from 2012 levels by 2025. In a second example, in December 2014, the EPA published a proposed rulemaking that it expects to finalize by October 1, 2015, which rulemaking proposes to revise the National Ambient Air Quality Standard for ozone to between 65 to 70 parts per billion for both the 8-hour primary and secondary standards.

Voluntary remediation of subsurface contamination is in process at certain of the Company's refinery sites. The remedial projects are being overseen by the appropriate state agencies. Based on current investigative and remedial activities, the Company believes that the 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 San Antonio Acquisition, 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 ("TCEQ"), 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.

Montana Refinery

In connection with the acquisition of the Montana refinery from Connacher Oil and Gas Limited ("Connacher"), the Company became a party to an existing 2002 Refinery Initiative Consent Decree ("Montana Consent Decree") with the EPA and the Montana Department of Environmental Quality ("MDEQ"). The material obligations imposed by the Montana 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 Montana refinery. The Company believes the majority of damages related to such contamination at the Montana refinery are covered by a contractual indemnity provided by Holly Frontier Corporation ("Holly"), the owner and operator of the Montana refinery prior to its acquisition by Connacher, under an asset purchase agreement between Holly and Connacher, pursuant to which Connacher acquired the Montana 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 cap, for environmental conditions arising under Holly's ownership and operation of the Montana 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 $17.7 million as of March 31, 2015, of which $14.5 million was capitalized and $3.2 million was expensed. The Company continues to believe that Holly is responsible to indemnify the Company for these remediation expenses disputed by Holly, and the parties have participated in mediation in accordance with the dispute resolution procedure set forth in the asset purchase agreement to resolve this issue. In the event the Company is unsuccessful, the Company will be responsible for those remediation expenses. The Company expects that it may incur some expenses to remediate other environmental conditions at the Montana refinery in connection with the current capacity expansion of the 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. The Company estimates costs of up to $1.0 million as of March 31, 2015 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 months ended March 31, 2015 and 2014, the Company incurred approximately $0.3 million and $0.4 million, respectively, related to installing process equipment at the Superior refinery pursuant to the 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 the Company’s financial results or 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 Superior Acquisition and (iii) certain liabilities for certain third party actions, suits or proceedings alleging exposure, prior to the Superior Acquisition, 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 Superior Acquisition, which named the Company and Murphy Oil as insureds and covers environmental conditions existing at the Superior refinery prior to the Superior Acquisition.

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 March 31, 2015 and 2014, the Company incurred approximately $1.0 million and $0.1 million, respectively, of such expenditures and estimates additional expenditures of approximately $9.0 million to $11.0 million of capital expenditures and expenditures related to additional personnel and environmental studies over the next two years as a result of the implementation of these requirements. These capital investment requirements will be 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 results or 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 March 31, 2015, 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 Bel-Ray Acquisition, the Company became a party to the Weston Agreement.

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

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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 March 31, 2015 and 2014, the Company incurred $0.1 million and $0.2 million, respectively, of related capital expenditures and expects to incur up to $1.0 million during 2015 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 under this OSHA initiative. 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 results of operations or financial condition.

Labor Matters

The Company has employees covered by various collective bargaining agreements. The Company's Karns City facility collective bargaining agreement was ratified on April 9, 2015 and will expire on January 31, 2019. The Montana refinery collective bargaining agreement expired on January 31, 2015 and is currently on a 24-hour rolling contract until a new agreement is ratified.

Legal Proceedings

The Company is involved in the legal proceedings described below and is subject to other 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 its unaudited 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 the matters described below and other 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. Accordingly, the Company discloses matters below for which a material loss is reasonably possible. In each case, however, the Company has either determined that the range of loss is not reasonably estimable or that any reasonably estimable range of loss is not material to its unaudited condensed consolidated financial statements.

On November 12, 2014, a nationwide collective action lawsuit alleging that Anchor, a wholly owned subsidiary of the Company, failed to pay drilling fluid engineers overtime in compliance with the Fair Labor Standards Act ("FLSA") was filed titled Jonathan Wolfe v. Anchor Drilling Fluids USA, Inc. in the U.S. District Court for the Western District of Pennsylvania ("Wolfe"). The Company filed its answer to the complaint on January 9, 2015 and the Wolfe plaintiff filed an amended complaint on February 26, 2015, adding that Anchor's failure to pay overtime to a subclass of drilling fluid engineers violated the Pennsylvania Minimum Wage Act (the “Pennsylvania Act”). For this subclass, the Wolfe plaintiff seeks certification of a class action under the Pennsylvania Act. The Wolfe plaintiff seeks to recover overtime pay, liquidated damages and attorneys’ fees and costs. The portion of the potential liability that relates to the period prior to March 31, 2014, the date on which the Company acquired Anchor, is eligible for indemnification under the securities purchase agreement that effected that transaction; however, the right to indemnification under the securities purchase agreement for the potential Wolfe liability is subject to a deductible and limitations otherwise set forth in the securities purchase agreement. On May 1, 2015, the parties engaged in mediation and agreed to a tentative settlement of this litigation. The tentative settlement must be approved by the U.S. District Court. The tentative settlement amount is not material to the unaudited condensed consolidated financial statements.

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On November 21, 2014, a nationwide collective action lawsuit alleging that Anchor and the Company, as well as SOS, failed to pay solids control technicians overtime in compliance with the FLSA was filed titled Timothy Niver v. Specialty Oilfield Solutions, Ltd., et al. in the U.S. District Court for the Western District of Pennsylvania (“Niver”). The Niver plaintiff filed an amended complaint on January 21, 2015, adding that defendants’ failure to pay overtime to a subclass of solids control technicians violated the Pennsylvania Act. For this subclass, the Niver plaintiff seeks certification of a class action under the Pennsylvania Act. The Niver plaintiff seeks to recover overtime pay, liquidated damages and attorneys’ fees and costs. Anchor and the Company filed their answer to the amended complaint on February 2, 2015. The Company consented to conditional certification in the case, and notice of the collective action has been issued to potential class members. The portion of the potential liability that relates to the period prior to August 1, 2014, the date on which the Company acquired the assets of SOS, was retained by, and is the responsibility of, SOS. To the extent Anchor or the Company is found liable for damages relating to the period prior to the acquisition of the assets of SOS, Anchor and the Company are eligible for indemnification under the asset purchase agreement that effected that transaction, and no deductible is applicable; however, the right to indemnification is subject to limitations otherwise set forth in the asset purchase agreement. The parties are scheduled to mediate the Niver case on June 5, 2015.

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 March 31, 2015 and December 31, 2014, the Company had outstanding standby letters of credit of $65.3 million and $114.3 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 March 31, 2015 and December 31, 2014, 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 March 31, 2015 and December 31, 2014) with the consent of the Agent (as defined in the revolving credit facility agreement).

As of March 31, 2015 and December 31, 2014, the Company had availability to issue letters of credit of $497.6 million and $310.8 million, respectively, under its revolving credit facility.

7. Long-Term Debt

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

	March 31, 2015	December 31, 2014
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 3.0% at March 31, 2015	$0.1	$150.8
Borrowings under 2020 Notes, interest at a fixed rate of 9.625%, interest payments semiannually, borrowings due August 2020, effective interest rate of 10.1% for the three months ended March 31, 2015	275.0	275.0
Borrowings under 2021 Notes, interest at a fixed rate of 6.50%, interest payments semiannually, borrowings due April 2021, effective interest rate of 6.7% for the three months ended March 31, 2015	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 three months ended March 31, 2015 (1)	353.1	352.5
Borrowings under 2023 Notes, interest at a fixed rate of 7.75%, interest payments semiannually, borrowings due April 2023, effective interest rate of 7.8% for the three months ended March 31, 2015	325.0	—
Capital lease obligations, at various interest rates, interest and principal payments monthly through October 2034	43.5	43.6
Less unamortized discounts	(10.6)	(8.4)

Total long-term debt	1,886.1	1,713.5
Less current portion of long-term debt	272.0	0.6
	$1,614.1	$1,712.9

(1) The balance includes a fair value interest rate hedge adjustment, which increased the debt balance by $3.1 million and $2.5 million as of March 31, 2015 and December 31, 2014, respectively (refer to Note 8 for additional information on the interest rate swap designated as a fair value hedge).

Senior Notes

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 of 1933, as amended (the “Securities Act”), to eligible purchasers at a discounted price of 99.257 percent of par. The 2023 Notes were resold to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to persons outside the U.S. pursuant to Regulation S under the Securities Act. 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 2020 Notes (defined below) 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.

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 2023 Notes with the net proceeds of a public or private equity offering at a redemption price of 107.75% 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 2023 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 2023 Notes at the redemption prices (expressed as percentages of principal amount) set forth below, plus accrued and unpaid interest to the applicable redemption date on such 2023 Notes, if redeemed during the twelve-month period beginning on April 15 of the years indicated below:

Year	Percentage	
2018	105.813	%
2019	103.875	%
2020	101.938	%
2021 and thereafter	100.000	%

Prior to April 15, 2018, the Company may on any one or more occasions redeem all or part of the 2023 Notes at a redemption price equal to the sum of: (1) the principal amount thereof, plus (2) the make-whole premium (as set forth in the indenture governing the 2023 Notes) at the redemption date, plus any accrued and unpaid interest to the applicable redemption date.

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 the Anchor Acquisition (refer to Note 3 for additional information), 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.

On March 24, 2015, the Company filed an exchange offer registration statement for the 2021 Notes with the SEC, which was declared effective on April 3, 2015. The exchange offer was completed on April 30, 2015, thereby fulfilling all of the requirements of the 2021 Notes registration rights agreement.

7.625% Senior Notes (the “2022 Notes”)

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

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9.625% Senior Notes (the “2020 Notes”)

On June 29, 2012, in connection with the acquisition of Royal Purple, Inc. (“Royal Purple”), the Company issued and sold $275.0 million in aggregate principal amount of 9.625% senior notes due August 1, 2020 in a private placement pursuant to Section 4(a)(2) of the Securities Act, to eligible purchasers at a discounted price of 98.25 percent of par. The Company received net proceeds of approximately $262.5 million, net of discount, initial purchasers’ fees and expenses, which the Company used to fund a portion of the purchase price of Royal Purple. Interest on the 2020 Notes is paid semiannually in arrears on February 1 and August 1 of each year, beginning on February 1, 2013.

On April 27, 2015, the Company redeemed $96.2 million aggregate principal amount of 2020 Notes with a portion of the net proceeds of the March 13, 2015 public offering of its common units in which it sold 6,000,000 common units. Additionally, on April 28, 2015, the Company redeemed the remaining $178.8 million aggregate principal amount of 2020 Notes with a portion of the net proceeds from the issuance of the 2023 Notes. In conjunction with the redemptions, the Company incurred debt extinguishment costs of $46.6 million. As a result of the redemptions, the 2020 Notes less unamortized debt discount are classified in current portion of long-term debt in the condensed consolidated balance sheet as of March 31, 2015.

2020 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 2020, 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 2020, 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 2020, 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 2020, 2021, 2022 and 2023 Notes.

The indentures governing the 2020, 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; (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 2020, 2021, 2022 and 2023 Notes are rated investment grade by either Moody’s Investors Service, Inc. (“Moody’s”) or Standard & Poor’s Ratings Services (“S&P”) and no Default or Event of Default, each as defined in the indentures governing the 2020, 2021, 2022 and 2023 Notes, has occurred and is continuing, many of these covenants will be suspended, except in the case of the 2020 Notes, an investment grade rating is required from both Moody’s and S&P. As of March 31, 2015, the Company’s Fixed Charge Coverage Ratio (as defined in the indentures governing the 2020, 2021, 2022 and 2023 Notes) was 2.7 to 1.0. As of March 31, 2015, the Company was in compliance with all covenants under the indentures governing the 2020, 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 prime plus a basis points margin or London Interbank Offered Rate ("LIBOR") plus a basis points margin, at the Company's option. As of March 31, 2015, the margin was 75 basis points for prime and 175 basis points for LIBOR; however, the margin can fluctuate quarterly based on the Company's average availability for additional borrowings under the revolving credit facility in the preceding calendar 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

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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 at March 31, 2015 under the revolving credit facility was $563.0 million. As of March 31, 2015, the Company had $0.1 million in outstanding borrowings under the revolving credit facility and outstanding standby letters of credit of $65.3 million, leaving $497.6 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.

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, 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 March 31, 2015, the Company was in compliance with all covenants under the revolving credit facility.

Maturities of Long-Term Debt

As of March 31, 2015, principal payments on debt obligations and future minimum rentals on capital lease obligations are as follows (in millions):

Year	
2015	$275.5
2016	0.7
2017	0.7
2018	0.8
2019	0.9
Thereafter	1,615.0
Total	$1,893.6

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 and options, 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 NYMEX 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.

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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. These 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.

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 March 31, 2015 and December 31, 2014 (in millions):

	March 31, 2015			December 31, 2014		
	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 designated as hedges:						
Fuel products segment:						
Crude oil swaps	$—	$—	$—	$—	$ (10.0)	$ (10.0)
Gasoline swaps	—	—	—	15.9	(4.4)	11.5
Swaps not allocated to a specific segment:						
Interest rate swaps	—	—	—	2.5	—	2.5
Total derivative instruments designated as hedges	—	—	—	18.4	(14.4)	4.0
Derivative instruments not designated as hedges:						
Fuel products segment:						
Crude oil swaps	0.8	(0.8)	—	31.4	(111.2)	(79.8)
Crude oil basis swaps	—	—	—	0.8	—	0.8
Crude oil percent basis swaps	0.3	(0.3)	—	—	(0.2)	(0.2)
Crude oil options	2.4	(2.4)	—	—	—	—
Gasoline swaps	1.3	(1.3)	—	2.4	(0.4)	2.0
Gasoline crack spread swaps	0.2	(0.2)	—	—	—	—
Diesel swaps	5.3	(5.3)	—	116.1	(19.1)	97.0
Diesel crack spread swaps	0.3	(0.3)	—	4.5	—	4.5
Jet fuel swaps	—	—	—	7.9	(5.2)	2.7

Platinum swaps	—	—	—	—	(0.1)	(0.1)
Specialty products segment:						
Natural gas swaps	0.1	(0.1)	—	—	(7.2)	(7.2)
Natural gas collars	—	—	—	0.1	(0.6)	(0.5)
Total derivative instruments not designated as hedges	10.7	(10.7)	—	163.2	(144.0)	19.2
Total derivative instruments	$ 10.7	$ (10.7)	$ —	$ 181.6	$ (158.4)	$ 23.2

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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 March 31, 2015 and December 31, 2014 (in millions):

	March 31, 2015			December 31, 2014		
	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 designated as hedges:						
Fuel products segment:						
Crude oil swaps	$—	$—	$—	$(13.8)	$10.0	$(3.8)
Gasoline swaps	—	—	—	—	4.4	4.4
Total derivative instruments designated as hedges	—	—	—	(13.8)	14.4	0.6
Derivative instruments not designated as hedges:						
Fuel products segment:						
Crude oil swaps	(8.8)	0.8	(8.0)	(102.4)	111.2	8.8
Crude oil percent basis swaps	(0.1)	0.3	0.2	(0.2)	0.2	—
Crude oil options	(0.8)	2.4	1.6	—	—	—
Gasoline swaps	(2.1)	1.3	(0.8)	(1.0)	0.4	(0.6)
Gasoline crack spread swaps	(2.0)	0.2	(1.8)	—	—	—
Diesel swaps	—	5.3	5.3	(28.1)	19.1	(9.0)
Diesel crack spread swaps	(2.2)	0.3	(1.9)	—	—	—
Jet fuel swaps	—	—	—	(5.2)	5.2	—
Platinum swaps	(0.3)	—	(0.3)	(0.1)	0.1	—
Natural gas swaps	(0.3)	—	(0.3)	—	—	—
Specialty products segment:						
Natural gas swaps	(15.2)	0.1	(15.1)	(12.1)	7.2	(4.9)
Natural gas collars	(1.2)	—	(1.2)	(1.1)	0.6	(0.5)
Total derivative instruments not designated as hedges	(33.0)	10.7	(22.3)	(150.2)	144.0	(6.2)
Total derivative instruments	$(33.0)	$10.7	$(22.3)	$(164.0)	$158.4	$(5.6)

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 March 31, 2015, the Company had no counterparties in which derivatives held were net assets. As of December 31, 2014, the Company had five 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 Baa2 and A- 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 March 31, 2015 or

December 31, 2014. 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 March 31, 2015 and December 31, 2014, 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

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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.

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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 March 31, 2015 and 2014 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 Income on Derivatives (Effective Portion)		Amount of Gain (Loss) Reclassified from Accumulated Other Comprehensive Income into Net Income (Loss) (Effective Portion)			Amount of Gain (Loss) Recognized in Net Income (Loss) on Derivatives (Ineffective Portion)		
	Three Months Ended March 31,		Location of Gain (Loss)	Three Months Ended March 31,		Location of Gain (Loss)	Three Months Ended March 31,	
	2015	2014		2015	2014		2015	2014
Fuel products segment:								
Crude oil swaps	$ (6.3)	$ 17.7	Cost of sales	$ (21.5)	$ 9.5	Unrealized/ Realized	$ (0.2)	$ 17.4
Gasoline swaps	0.8	(1.8)	Sales	14.0	(5.7)	Unrealized/ Realized	0.7	(0.9)
Diesel swaps	0.1	20.0	Sales	4.8	(6.2)	Unrealized/ Realized	—	1.5
Jet fuel swaps	0.3	6.5	Sales	1.4	(1.2)	Unrealized/ Realized	—	0.1
Specialty products segment:								
Crude oil swaps	—	—	Cost of sales	(0.4)	(0.3)	Unrealized/ Realized	—	—
Total	$ (5.1)	$ 42.4		$ (1.7)	$ (3.9)		$ 0.5	$ 18.1

The effective portion of the cash flow hedges classified in accumulated other comprehensive income was a gain of $22.4 million and a gain of $25.8 million as of March 31, 2015 and December 31, 2014, 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 March 31, 2015 will be reclassified to earnings by December 31, 2016 with balances being recognized as follows (in millions):

Year	Accumulated Other Comprehensive Income
2015	$ 11.6
2016	10.8
Total	$ 22.4

Based on fair values as of March 31, 2015, the Company expects to reclassify $14.6 million of net gains on derivative instruments from accumulated other comprehensive income to earnings during the next twelve months due to actual crude oil purchases, diesel, gasoline and jet fuel sales. However, the amounts actually realized will be dependent on the fair values as of the dates of settlement.

Derivative Instruments Designated as Fair Value Hedges

For derivative instruments that are designated and qualify as a fair value hedge, 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 was recognized as 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 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

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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 months ended March 31, 2015 and 2014 related to its derivative instrument designated as a fair value hedge (in millions):

	Location of Gain (Loss) of Derivative	Amount of Loss Recognized in Net Income (Loss) Three Months Ended March 31,		Hedged Item	Location of Gain (Loss) on Hedged Item	Amount of Gain Recognized in Net Income (Loss) Three Months Ended March 31,	
		2015	2014			2015	2014
Swaps not allocated to a specific segment:							
Interest rate swap	Interest expense	$—	$(1.6)	2022 Notes	Interest expense	$—	$1.6
Total		$—	$(1.6)			$—	$1.6

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 diesel crack spread collars, gasoline crack spread collars, natural gas collars, and certain other crude oil swaps, diesel swaps, gasoline swaps, natural gas swaps, crude oil options and platinum swaps that are not designated as cash flow hedges for accounting purposes.

The amount reclassified from accumulated other comprehensive income (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 and losses in the unaudited condensed consolidated statements of operations for the three months ended March 31, 2015 and 2014 (in millions):

	Three Months Ended March 31,	
	2015	2014
Realized gain (loss) on derivative instruments	$1.2	$(1.1)

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The Company recorded the following gains (losses) in its unaudited condensed consolidated statements of operations for the three months ended March 31, 2015 and 2014 related to its derivative instruments not designated as hedges (in millions):

Type of Derivative	Amount of Gain (Loss) Recognized in Realized Gain on Derivative Instruments Three Months Ended March 31, 2015	2014	Amount of Gain (Loss) Recognized in Unrealized Gain (Loss) on Derivative Instruments Three Months Ended March 31, 2015	2014
Fuel products segment:				
Crude oil swaps	$(48.3)	$3.9	$50.2	$3.4
Crude oil basis swaps	1.0	0.6	(0.4)	1.3
Gasoline swaps	(2.0)	(3.6)	(1.1)	2.5
Diesel swaps	58.0	—	(63.4)	3.0
Diesel crack spread swaps	0.9	—	(6.4)	—
Gasoline crack spread swaps	(0.8)	—	(1.5)	—
Jet fuel swaps	1.6	(0.4)	(1.6)	(0.9)
Diesel crack spread collars	—	0.4	—	0.4
Platinum swaps	—	—	(0.1)	—
Natural gas swaps	—	—	(0.3)	—
Gasoline crack spread collars	—	—	—	0.7
Specialty products segment:				
Natural gas swaps	(2.1)	0.9	(3.2)	0.9
Total	$8.3	$1.8	$(27.8)	$11.3

Derivative Positions - Specialty Products Segment

Natural Gas Swap Contracts

At March 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
Second Quarter 2015	1,500,000	$4.11
Third Quarter 2015	1,500,000	$4.11
Fourth Quarter 2015	1,900,000	$4.12
Calendar Year 2016	5,880,000	$4.22
Calendar Year 2017	4,950,000	$3.85
Total	15,730,000	
Average price		$4.07

At December 31, 2014, 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 2015	1,770,000	$4.09
Second Quarter 2015	1,500,000	$4.11
Third Quarter 2015	1,500,000	$4.11
Fourth Quarter 2015	1,900,000	$4.12
Calendar Year 2016	5,880,000	$4.22
Calendar Year 2017	1,830,000	$4.28
Total	14,380,000	
Average price		$4.18

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Natural Gas Collars

At March 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)
Second Quarter 2015	240,000	$4.25	$3.79
Third Quarter 2015	240,000	$4.25	$3.79
Fourth Quarter 2015	200,000	$4.25	$3.85
Calendar Year 2016	600,000	$4.25	$3.89
Total	1,280,000		
Average price		$4.25	$3.84

At December 31, 2014, 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 2015	240,000	$4.25	$3.79
Second Quarter 2015	240,000	$4.25	$3.79
Third Quarter 2015	240,000	$4.25	$3.79
Fourth Quarter 2015	200,000	$4.25	$3.85
Calendar Year 2016	600,000	$4.25	$3.89
Total	1,520,000		
Average price		$4.25	$3.84

Derivative Positions - Fuel Products Segment

Natural Gas Swap Contracts

At March 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
Calendar Year 2016	1,320,000	$3.38
Total	1,320,000	
Average price		$3.38

Crude Oil Swap Contracts

At March 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)
Second Quarter 2015	1,016,000	11,165	$50.99
Third Quarter 2015	493,350	5,363	$57.51
Fourth Quarter 2015	309,350	3,363	$58.32
Calendar Year 2016	720,288	1,968	$62.71
Total	2,538,988		
Average price			$56.48

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At March 31, 2015, the Company had the following derivatives related to crude oil sales in its fuel products segment, none of which are designated as hedges.

Crude Oil Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
Third Quarter 2015	120,000	1,304	$38.75
Total	120,000		
Average price			$38.75

At December 31, 2014, the Company had the following derivatives related to crude oil purchases in its fuel products segment, all of which are designated as cash flow hedges.

Crude Oil Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Swap ($/Bbl)
First Quarter 2015	315,000	3,500	$97.71
Total	315,000		
Average price			$97.71

At December 31, 2014, 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 2015	1,674,000	18,600	$89.55
Second Quarter 2015	91,000	1,000	$89.89
Third Quarter 2015	386,400	4,200	$69.20
Fourth Quarter 2015	386,400	4,200	$69.20
Calendar Year 2016	972,828	2,658	$78.02
Total	3,510,628		
Average price			$81.89

At December 31, 2014, the Company had the following derivatives related to crude oil sales in its fuel products segment, none of which are designated as hedges.

Crude Oil Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
First Quarter 2015	1,674,000	18,600	$84.21
Total	1,674,000		
Average price			$84.21

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 Canadian heavy crude oil and NYMEX WTI crude oil, pricing differentials between LLS and NYMEX WTI and pricing differentials between MSW and NYMEX WTI. At December 31, 2014, 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 2015	118,000	2,000	$(22.40)
Total	118,000		
Average differential			$(22.40)

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Crude Oil Percent Basis Swap Contracts

The Company entered into derivative instruments to secure a percentage differential on WCS crude oil to NYMEX WTI. At March 31, 2015, the Company had the following derivatives related to crude oil percent basis swaps in its fuel products segment, none of which are designated as hedges.

Crude Oil Percent Basis Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Fixed Percentage of NYMEX WTI (Average % of WTI/Bbl)	
Third Quarter 2015	184,000	2,000	73.0	%
Fourth Quarter 2015	184,000	2,000	73.0	%
Calendar Year 2016	732,000	2,000	75.0	%
Total	1,100,000			
Average percentage			74.3	%

At December 31, 2014, the Company had the following derivatives related to crude oil percent basis swaps in its fuel products segment, none of which are designated as hedges.

Crude Oil Percent Basis Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Fixed Percentage of NYMEX WTI (Average % of WTI/Bbl)	
Third Quarter 2015	184,000	2,000	73.0	%
Fourth Quarter 2015	184,000	2,000	73.0	%
Total	368,000			
Average percentage			73.0	%

Crude Oil Option Contracts

During the first quarter of 2015, the Company entered into derivative instruments to mitigate the risk of future changes in the price of NYMEX WTI crude oil. At March 31, 2015, the Company had the following derivatives related to crude oil options in its fuel products segment, none of which are designated as hedges.

Crude Oil Option Contracts by Expiration Dates	Barrels Purchased and Sold	BPD	Average Bought Put ($/Bbl)	Average Sold Call ($/Bbl)
Second Quarter 2015	1,000,000	10,989	$48.00	$—
Fourth Quarter 2015	500,000	5,435	$—	$70.00
Total	1,500,000			
Average price			$48.00	$70.00

Diesel Swap Contracts

At March 31, 2015, the Company had the following derivatives related to diesel sales in its fuel products segment, none of which are designated as hedges.

Diesel Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
Third Quarter 2015	230,000	2,500	$78.44
Fourth Quarter 2015	230,000	2,500	$78.44
Calendar Year 2016	549,000	1,500	$82.28
Total	1,009,000		
Average price			$80.53

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At December 31, 2014, the Company had the following derivatives related to diesel sales in its fuel products segment, none of which are designated as hedges.

Diesel Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
First Quarter 2015	1,449,000	16,100	$116.27
Second Quarter 2015	91,000	1,000	$117.92
Third Quarter 2015	322,000	3,500	$95.04
Fourth Quarter 2015	322,000	3,500	$95.04
Calendar Year 2016	915,000	2,500	$104.32
Total	3,099,000		
Average price			$108.38

At December 31, 2014, the Company had the following derivatives related to diesel purchases in its fuel products segment, none of which are designated as hedges.

Diesel Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Swap ($/Bbl)
First Quarter 2015	1,449,000	16,100	$105.78
Total	1,449,000		
Average price			$105.78

Diesel Percent Basis Crack Spread Swap Contracts

At March 31, 2015, the Company had the following diesel percent basis crack spread swap contracts in its fuel products segment, none of which are designated as hedges.

Diesel Percent Basis Crack Spread Swap Contracts by Expiration Dates	Barrels Sold	BPD	Fixed Percentage of NYMEX WTI (Average % of WTI/Bbl)	
Third Quarter 2015	506,000	5,500	33.1	%
Fourth Quarter 2015	506,000	5,500	33.1	%
Calendar Year 2016	2,196,000	6,000	31.8	%
Total	3,208,000			
Average percentage			32.2	%

At December 31, 2014, the Company had the following diesel percent basis crack spread swap contracts in its fuel products segment, none of which are designated as hedges.

Diesel Percent Basis Crack Spread Swap Contracts by Expiration Dates	Barrels Sold	BPD	Fixed Percentage of NYMEX WTI (Average % of WTI/Bbl)	
Third Quarter 2015	414,000	4,500	33.2	%
Fourth Quarter 2015	414,000	4,500	33.2	%
Calendar Year 2016	1,647,000	4,500	31.7	%
Total	2,475,000			
Average percentage			32.2	%

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Jet Fuel Swap Contracts

At December 31, 2014, the Company had the following derivatives related to jet fuel sales in its fuel products segment, none of which are designated as cash flow hedges.

Jet Fuel Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
First Quarter 2015	180,000	2,000	$115.65
Total	180,000		
Average price			$115.65

At December 31, 2014, the Company had the following derivatives related to jet fuel purchases in its fuel products segment, none of which are designated as hedges.

Jet Fuel Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Swap ($/Bbl)
First Quarter 2015	180,000	2,000	$100.91
Total	180,000		
Average price			$100.91

Gasoline Swap Contracts

At March 31, 2015, the Company had the following derivatives related to gasoline sales in its fuel products segment, none of which are designated as hedges.

Gasoline Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
Second Quarter 2015	1,016,000	11,165	$68.54
Third Quarter 2015	184,000	2,000	$70.44
Total	1,200,000		
Average price			$68.84

At December 31, 2014, the Company had the following derivatives related to gasoline sales in its fuel products segment, all of which are designated as cash flow hedges.

Gasoline Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
First Quarter 2015	315,000	3,500	$109.68
Total	315,000		
Average price			$109.68

At December 31, 2014, the Company had the following derivatives related to gasoline sales in its fuel products segment, none of which are designated as hedges.

Gasoline Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
First Quarter 2015	45,000	500	$111.72
Total	45,000		
Average price			$111.72

At December 31, 2014, the Company had the following derivatives related to gasoline purchases in its fuel products segment, none of which are designated as hedges.

Gasoline Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Swap ($/Bbl)
First Quarter 2015	45,000	500	$78.12
Total	45,000		
Average price			$78.12

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Gasoline Crack Spread Swaps
At March 31, 2015, the Company had the following derivatives related to gasoline crack spreads in its fuel products segment, none of which are designated as hedges.

Gasoline Crack Spread Swap Contracts by Expiration Dates	Barrels Sold	BPD	Fixed Dollars Above NYMEX WTI (Average $ over WTI/Bbl)
Second Quarter 2015	833,000	9,154	$18.43
Third Quarter 2015	138,000	1,500	$14.35
Total	971,000		
Average price			$17.85

Platinum Swap Contracts
At March 31, 2015 and December 31, 2014, the Company had approximately 1,900 troy ounces of platinum swap contracts through 2015 in its fuel products segment, none of which are designated as hedges.
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 Baa2 and A- 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 March 31, 2015, the Company’s net liability was reduced by approximately $0.4 million. As a result of applying the CVA at December 31, 2014, the Company’s net asset was increased by approximately $2.0 million and net liability was reduced by

approximately $0.1 million.

Observable inputs utilized to estimate the fair values of the Company's derivative instruments were primarily based 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 March 31, 2015, 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. See Note 11 for further information on pension assets.

Liability Awards

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

Renewable Identification Numbers Obligation

The Company's RINs obligation (" RINs Obligation") represents a liability for the purchase of RINs to satisfy the EPA requirement to blend biofuels into the fuel products it produces pursuant to the EPA's Renewable Fuel Standard. 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 and the price of those RINs as of the balance sheet date. 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.

For the three months ended March 31, 2015, the Company sold approximately 49 million RINs for a gain of $35.0 million, net of cost to generate, recorded in cost of sales in the condensed consolidated statement of operations. As of March 31, 2015, the Company had a RINs Obligation of approximately 81 million RINs, which resulted in a mark-to-market loss of approximately $42.2 million.

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Hierarchy of Recurring Fair Value Measurements

The Company’s recurring assets and liabilities measured at fair value at March 31, 2015 and December 31, 2014 were as follows (in millions):

	March 31, 2015				December 31, 2014			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Derivative assets:								
Crude oil swaps	$—	$—	$—	$—	$—	$—	$(89.8)	$(89.8)
Crude oil basis swaps	—	—	—	—	—	—	0.8	0.8
Crude oil percent basis swaps	—	—	—	—	—	—	(0.2)	(0.2)
Gasoline swaps	—	—	—	—	—	—	13.5	13.5
Diesel swaps	—	—	—	—	—	—	97.0	97.0
Diesel crack spread swaps	—	—	—	—	—	—	4.5	4.5
Jet fuel swaps	—	—	—	—	—	—	2.7	2.7
Natural gas swaps	—	—	—	—	—	—	(7.2)	(7.2)
Natural gas collars	—	—	—	—	—	—	(0.5)	(0.5)
Platinum swaps	—	—	—	—	—	—	(0.1)	(0.1)
Interest rate swaps	—	—	—	—	—	—	2.5	2.5
Total derivative assets	—	—	—	—	—	—	23.2	23.2
Pension plan investments	0.6	50.2	—	50.8	0.2	49.4	—	49.6
Total recurring assets at fair value	$0.6	$50.2	$—	$50.8	$0.2	$49.4	$23.2	$72.8
Liabilities:								
Derivative liabilities:								
Crude oil swaps	$—	$—	$(8.0)	$(8.0)	$—	$—	$5.0	$5.0
Crude oil percent basis swaps	—	—	0.2	$0.2	—	—	—	—
Gasoline swaps	—	—	(0.8)	(0.8)	—	—	3.8	3.8
Gasoline crack spread swaps	—	—	(1.8)	(1.8)	—	—	—	—
Diesel swaps	—	—	5.3	5.3	—	—	(9.0)	(9.0)
Diesel crack spread options	—	—	(1.9)	(1.9)	—	—	—	—
Natural gas swaps	—	—	(15.4)	(15.4)	—	—	(4.9)	(4.9)
Natural gas collars	—	—	(1.2)	(1.2)	—	—	(0.5)	(0.5)
Platinum swaps	—	—	(0.3)	(0.3)	—	—	—	—
Crude oil options	—	—	1.6	1.6	—	—	—	—
Total derivative liabilities	—	—	(22.3)	(22.3)	—	—	(5.6)	(5.6)
RINs Obligation	—	(57.9)	—	(57.9)	—	(16.3)	—	(16.3)
Liability Awards	(5.6)	—	—	(5.6)	(4.7)	—	—	(4.7)
Total recurring liabilities at fair value	$(5.6)	$(57.9)	$(22.3)	$(85.8)	$(4.7)	$(16.3)	$(5.6)	$(26.6)

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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 three months ended March 31, 2015 and 2014 (in millions):

	Three Months Ended March 31,	
	2015	2014
Fair value at January 1,	$17.6	$(54.8)
Realized gain on derivative instruments	(8.9)	(6.6)
Unrealized gain (loss) on derivative instruments	(27.9)	24.6
Interest expense, net	(0.2)	(1.9)
Change in fair value of cash flow hedges	(5.1)	42.4
Settlements	2.2	9.3
Transfers in (out) of Level 3	—	—
Fair value at March 31,	$(22.3)	$13.0
Total gain (loss) included in net income (loss) attributable to changes in unrealized gain (loss) relating to financial assets and liabilities held as of March 31,	$(27.9)	$24.6

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.

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 March 31, 2015 and December 31, 2014 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 and

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capital lease obligations approximate their fair values as determined by discounted cash flows and are classified as Level 3. See Note 7 for further information on long-term debt.

The Company's carrying and estimated fair value of the Company's financial instruments, carried at adjusted historical cost, at March 31, 2015 and December 31, 2014 were as follows (in millions):

		March 31, 2015		December 31, 2014	
	Level	Fair Value	Carrying Value	Fair Value	Carrying Value
Financial Instrument:					
Senior notes	1	$661.9	$ 619.9	$630.0	$ 619.1
Senior notes	2	$1,203.3	$ 1,222.6	$803.3	$ 900.0
Revolving credit facility	3	$0.1	$ 0.1	$150.8	$ 150.8
Capital lease and other obligations	3	$43.5	$ 43.5	$43.6	$ 43.6

10. Partners' Capital

On March 13, 2015, the Company completed a public offering of its common units in which it sold 6,000,000 common units to the underwriters of the offering at a price to the public of $26.75 per unit. The proceeds received by the Company from this offering (net of underwriting discounts, commissions and expenses but before its general partner's capital contribution) were approximately $154.0 million and were used to redeem a portion of the 2020 Notes and to repay borrowings under its revolving credit facility. Underwriting discounts totaled approximately $6.4 million. The Company's general partner contributed $3.3 million to maintain its 2% general partner interest.

The Company has entered into an Equity Placement Agreement with various sales agents under which the Company may issue and sell, 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 provides the Company the right, but not the obligation, to sell common units in the future, at prices the Company deems appropriate. These sales, if any, will be 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 will be used for general partnership purposes, which may include, among other things, repayment of indebtedness, working capital, capital expenditures and acquisitions. The Company's general partner may contribute its proportionate capital contribution to retain its 2% general partner interest. For the three months ended March 31, 2015, the Company sold 307,985 common units for net proceeds of approximately $7.7 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 had no sales of its common units during the three months ended March 31, 2014.

The Company's distribution policy is defined in its partnership agreement. For the three months ended March 31, 2015 and 2014, the Company made distributions of $52.7 million and $52.6 million, respectively, to its partners. For the three months ended March 31, 2015 and 2014, the general partner was allocated $4.2 million and $3.8 million, respectively, in incentive distribution rights.

11. Employee Benefit Plans

The components of net periodic pension cost for the three months ended March 31, 2015 and 2014 were as follows (in millions):

	Three Months Ended March 31,	
	2015	2014
Service cost	$0.1	$0.1
Interest cost	0.7	0.7
Expected return on assets	(0.8)	(0.8)
Amortization of net loss	0.2	0.2
Net periodic benefit cost	$0.2	$0.2

At March 31, 2015 and December 31, 2014, the Company's investments associated with its pension plan 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 NAV of shares in each fund held by the pension plan at quarter end as provided by the third party administrator.

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See Note 9 for the definitions of Levels 1, 2 and 3. The Company's pension plan assets measured at fair value at March 31, 2015 and December 31, 2014 were as follows (in millions):

	March 31, 2015		December 31, 2014	
	Level 1	Level 2	Level 1	Level 2
Cash and cash equivalents	$0.6	$—	$0.2	$—
Domestic equities	—	10.0	—	10.0
Foreign equities	—	9.7	—	9.4
Fixed income	—	30.5	—	30.0
	$0.6	$50.2	$0.2	$49.4

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 Income (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 months ended March 31, 2015 and 2014 (in millions):

Components of Accumulated Other Comprehensive Income (Loss)	Amount Reclassified From Accumulated Other Comprehensive Income (Loss) Three Months Ended March 31,		Location of Gain (Loss)
	2015	2014	
Derivative gains (losses) on cash flow hedges:			
	$20.2	$(13.1)	Sales
	(21.9)	9.2	Cost of sales
	$(1.7)	$(3.9)	Total
Amortization of defined benefit pension and postretirement health benefit plans:			
Amortization of net loss	$(0.2)	$(0.2)	[1]
	$(0.2)	$(0.2)	Total

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

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13. Earnings Per Unit

The following table sets forth the computation of basic and diluted earnings per limited partner unit for the three months ended March 31, 2015 and 2014 (in millions, except unit and per unit data):

	Three Months Ended March 31, 2015	2014
Numerator for basic and diluted earnings per limited partner unit:		
Net income (loss)	$23.8	$(49.8)
General partner's interest in net income (loss)	0.5	(1.0)
General partner's incentive distribution rights	4.2	3.8
Non-vested share based payments	—	—
Net income (loss) available to limited partners	$19.1	$(52.6)
Denominator for basic and diluted earnings per limited partner unit:		
Basic weighted average limited partner units outstanding	71,232,392	69,622,884
Effect of dilutive securities:		
Participating securities — phantom units	43,060	—
Diluted weighted average limited partner units outstanding [1]	71,275,452	69,622,884
Limited partners' interest basic and diluted net income (loss) per unit	$0.27	$(0.76)

[1] Total diluted weighted average limited partner units outstanding excludes 0.1 million of dilutive phantom units for the three months ended March 31, 2014.

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 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, production chemicals and solids control services to the oil and gas exploration 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 2014 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 evaluates performance based upon Adjusted EBITDA. 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) unrealized losses from mark to market accounting for hedging activities; (e) realized gains under derivative instruments excluded from the determination of net income (loss); (f) 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); (g) debt refinancing fees, premiums and penalties and (h) 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.

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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. Reportable segment information for the three months ended March 31, 2015 and 2014 is as follows (in millions):

Three Months Ended March 31, 2015	Specialty Products	Fuel Products	Oilfield Services	Combined Segments	Eliminations	Consolidated Total
Sales:						
External customers	$361.6	$568.3	$88.7	$1,018.6	$—	$1,018.6
Intersegment sales	1.3	12.9	—	14.2	(14.2)	—
Total sales	$362.9	$581.2	88.7	$1,032.8	$(14.2)	$1,018.6
Adjusted EBITDA	$61.6	$67.4	$(4.1)	$124.9	$—	$124.9
Reconciling items to net income:						
Depreciation and amortization	15.9	20.0	5.6	41.5	—	41.5
Realized gain on derivatives, not reflected in net income	0.4	5.7	—	6.1	—	6.1
Unrealized loss on derivatives						27.9
Interest expense						27.0
Non-cash equity based compensation and other non-cash items						3.4
Income tax benefit						(4.8)
Net income						$23.8

Three Months Ended March 31, 2014	Specialty Products	Fuel Products	Oilfield Services	Combined Segments	Eliminations	Consolidated Total
Sales:						
External customers	$450.0	$891.0	$—	$1,341.0	$—	$1,341.0
Intersegment sales	—	17.2	—	17.2	(17.2)	—
Total sales	$450.0	$908.2	$—	$1,358.2	$(17.2)	$1,341.0
Adjusted EBITDA	$57.7	$25.0	$—	$82.7	$—	$82.7
Reconciling items to net loss:						
Depreciation and amortization	16.7	19.3	—	36.0	—	36.0
Realized gain on derivatives, not reflected in net loss	0.3	1.2	—	1.5	—	1.5
Unrealized gain on derivatives						(24.6)
Interest expense						26.2
Debt extinguishment costs						89.6
Non-cash equity based compensation and other non-cash items						3.6
Income tax expense						0.2

Net loss	$(49.8)

b. Geographic Information

International sales accounted for less than 10% of consolidated sales in each of the three months ended March 31, 2015 and 2014. 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 March 31, 2015 and 2014 (in millions):

	Three Months Ended March 31,					
	2015			2014		
Specialty products:						
Lubricating oils	$149.8	14.7	%	$197.7	14.7	%
Solvents	86.2	8.5	%	131.4	9.8	%
Waxes	39.0	3.8	%	35.4	2.6	%
Packaged and synthetic specialty products	80.5	7.9	%	76.4	5.7	%
Other	6.1	0.6	%	9.1	0.7	%
Total	$361.6	35.5	%	$450.0	33.5	%
Fuel products:						
Gasoline	$246.3	24.1	%	$359.6	26.8	%
Diesel	213.9	21.0	%	317.4	23.7	%
Jet fuel	38.2	3.8	%	44.0	3.3	%
Asphalt, heavy fuel oils and other	69.9	6.9	%	170.0	12.7	%
Total	$568.3	55.8	%	$891.0	66.5	%
Oilfield services:						
Total	$88.7	8.7	%	$—	—	%
Consolidated sales	$1,018.6	100.0	%	$1,341.0	100.0	%

d. Major Customers

During the three months ended March 31, 2015 and 2014, the Company had no customer that represented 10% or greater of consolidated sales.

e. Major Suppliers

During the three months ended March 31, 2015 and 2014, the Company had two suppliers that supplied approximately 48.1% and 47.8%, respectively, of its crude oil supply.

15. Subsequent Events

Subsequent events not disclosed elsewhere include the following:

On April 20, 2015, the Company declared a quarterly cash distribution of $0.685 per unit on all outstanding common units, or approximately $57.3 million (including the general partner’s incentive distribution rights) in aggregate, for the quarter ended March 31, 2015. The distribution will be paid on May 15, 2015 to unitholders of record as of the close of business on May 5, 2015. This quarterly distribution of $0.685 per unit equates to $2.74 per unit, or approximately $229.2 million (including the general partner’s incentive distribution rights) in aggregate on an annualized basis.

The fair value of the Company’s derivatives that were outstanding as of March 31, 2015 did not materially change subsequent to March 31, 2015. The fair value of the Company’s senior notes that were outstanding as of March 31, 2015 has increased by approximately $34.0 million subsequent to March 31, 2015.

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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 months ended March 31, 2015 and 2014. Unitholders should read the following discussion and analysis of the financial condition and results of operations of the Company in conjunction with our 2014 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, eastern Missouri and North Dakota. 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, as well as reselling purchased crude oil to third party customers. Our oilfield services segment manufactures and markets products and provides oilfield services including drilling fluids, completion fluids, production chemicals and solids control services to the oil and gas exploration industry throughout the U.S.
First Quarter 2015 Update
Financial Results
We generated Adjusted EBITDA (as defined in "Non-GAAP Financial Measures") of $124.9 million during the first quarter 2015, versus $82.7 million in the first quarter 2014. Balanced contributions from our specialty products and fuel products segments contributed to record first quarter 2015 Adjusted EBITDA, primarily due to a combination of strong operational reliability within our refining system; higher total production volumes; a significant decline in crude oil prices that contributed favorably to specialty products margins; and robust fuels refining economics. Improved year over year results within the specialty products and fuel products segments were partially offset by weakness within the oilfield services segment, which generated negative Adjusted EBITDA during the first quarter 2015.
Our specialty products segment generated Adjusted EBITDA of $61.6 million during the first quarter 2015, representing 49.3% of total Adjusted EBITDA during the period, versus $57.7 million in the first quarter 2014. A combination of lower feedstock costs, coupled with market share gains in select product categories, partially offset by a $23.7 million unfavorable lower of cost or market ("LCM") inventory adjustment, contributed to improved segment results, when compared to the first quarter 2014.
Our fuel products segment generated Adjusted EBITDA of $67.4 million during the first quarter 2015, representing 54.0% of total Adjusted EBITDA in the period, versus $25.0 million in the first quarter 2014. During the first quarter 2015, a combination of consistent reliability at our key fuels refineries and a nearly 10% year over year increase in fuel products segment production volumes, coupled with strong fuels refining economics, as indicated by a 21% year over year increase in the gasoline crack spread, contributed to stronger fuel products segment results.
Our oilfield services segment generated Adjusted EBITDA of $(4.1) million in the first quarter 2015, versus $9.7 million in the fourth quarter 2014. The oilfield services segment, which services approximately 10% of the domestic land-based rigs, was impacted by a more than 40% decline in the domestic land rig count that occurred between the fourth quarter 2014 and the first quarter 2015, as U.S. producers reduced drilling activity given a backdrop of lower

crude oil and natural gas prices. We are currently responding to the reduction in drilling activity with a corresponding reduction in operating costs within this segment, including a reduction in our oilfield services segment workforce that began in January 2015. Should drilling activity recover in the event of a rise in commodity prices, we are confident that we can appropriately staff our oilfield services segment according to the requirements of our customers.

The price of NYMEX West Texas Intermediate ("NYMEX WTI") crude oil remained volatile during the first quarter 2015. NYMEX WTI averaged approximately $49 per barrel in the first quarter 2015, down from $73 per barrel in the fourth quarter 2014 and $99 per barrel in the first quarter 2014. We believe a declining crude oil price environment is a positive development for our overall business, as changes in specialty product sales prices generally tend to lag behind feedstock price declines, while lower overall crude oil costs tend to translate into lower overall fuel costs for consumers, contributing positively to demand.

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 product 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 first-month futures price of NYMEX WTI crude oil, the price of U.S. Gulf Coast Pipeline 87 Octane Conventional Gasoline and U.S. Gulf Coast Pipeline Ultra-Low Sulfur Diesel (“ULSD”).

For the first quarter 2015, the Gulf Coast crack spread averaged approximately $19 per barrel, virtually unchanged from the first quarter 2014. The benchmark distillate margin declined 9% on a year over year basis during the first quarter 2015, although the gasoline crack spread increased by 21% when compared to the first quarter 2014. During the first quarter 2015, the Gulf Coast ULSD crack spread averaged $22 per barrel, while the Gulf Coast gasoline crack spread averaged $16 per barrel.

There are several factors that impact our refined product margins when compared to the benchmark crack spread. For example, several of our fuel products refineries produce asphalt and other residual products that may carry an average sales price below that of U.S. Gulf Coast gasoline or U.S. Gulf Coast ULSD crack spreads. Further, many of our fuel products refineries purchase select quantities of crude oil at a discount to NYMEX WTI, which helps support a higher capture rate, relative to the benchmark crack spread. Finally, some of our facilities, such as our Shreveport, Louisiana facility, produce both fuel and specialty products; given that our specialty products facilities generally operate at lower utilization rates than our fuel products facilities, facilities producing specialty products may incur higher operating expenses when compared to refineries that produce exclusively fuels, such as our Montana, San Antonio and Superior refineries. Based on our system-wide crude purchasing behaviors and overall production slate, we believe the Gulf Coast crack spread remains a helpful indicator in tracking directional shifts in refined product margins.

Distributable Cash Flow for the first quarter 2015 was $94.1 million, compared to $49.4 million in the first quarter 2014. A year over year improvement in gross profit was partially offset by higher replacement and environmental capital expenditures and higher cash interest expense.

CEO Transition

On March 26, 2015, we named William H. Hatch as Interim Chief Executive Officer (“CEO”) of Calumet, following the promotion of F. William Grube to Executive Vice Chairman. Our Board of Directors has convened a formal CEO Search Committee composed of its independent directors, retained The Miles Group to assist in establishing the correct selection criteria and retained Spencer Stuart, one of the world's leading executive search consulting firms, to assist in identifying the most qualified successors to Mr. Grube from a pool of both internal and external candidates. Mr. Hatch, a veteran executive within the downstream energy sector who served as the former head of operations for CITGO Petroleum Corporation, will remain in the role of Interim CEO until such time that a permanent successor to Mr. Grube is identified.

Shreveport Refinery Crude Oil Transportation Cost Reduction Initiative

We have entered into a 10-year, 20,000 barrel-per-day (“bpd”) pipeline agreement with Plains All American Pipeline, L.P. (“Plains”) to begin sourcing cost advantaged crude oil from the Midland, Texas and/or Cushing, Oklahoma markets by the first quarter 2017. Under a 10-year pipeline transportation agreement with Plains, we will have the option of shipping up to 20,000 bpd of either (1) Midland-priced crude oil from Midland, Texas to Longview, Texas; or (2) Cushing-priced crude oil from Cushing, Oklahoma to Longview, Texas. From the Longview, Texas hub, the crude oil will be shipped to our Shreveport refinery on the Caddo Pipeline, an 80,000 bpd pipeline owned by Plains and Delek Logistics Partners, L.P. that is expected to reach completion by mid-2016. We believe increased crude oil optionality provided by this agreement may provide approximately $7.0 million to $8.0 million in annualized crude oil transportation cost savings at the Shreveport refinery beginning in 2017.

Liquidity Update

On March 31, 2015, we had availability under our revolving credit facility of approximately $497.6 million, based on a $563.0 million borrowing base, $65.3 million in outstanding standby letters of credit and $0.1 million in outstanding borrowings. In addition, we had $272.8 million of cash on hand as of March 31, 2015. We completed the redemption of our 2020 Notes in April 2015 for approximately $319.0 million. Liquidity as of March 31, 2015 adjusted for this redemption would have been approximately $452.0 million. We believe we will continue to have ample liquidity from cash on hand, cash flow from operations and borrowing capacity under our revolving credit facility to meet our financial commitments, minimum quarterly distributions to unitholders, debt service obligations, contingencies and anticipated capital expenditures.

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Quarterly Cash Distribution

On April 20, 2015, we declared a quarterly cash distribution of $0.685 per unit, or $2.74 per unit on an annualized basis, for the quarter ended March 31, 2015 on all of our outstanding limited partner units. The distribution will be paid on May 15, 2015 to unitholders of record as of the close of business on May 5, 2015.

Renewable Fuels Standard Update

As set forth under the Renewable Fuels Standard ("RFS"), the Environmental Protection Agency ("EPA" or the "Agency") provides annual requirements for the total volume of renewable transportation fuels, including ethanol and advanced biofuels that are mandated to be blended into petroleum-based fuels. Under the RFS, domestic producers of petroleum fuels are "Obligated Blenders" of renewable fuels and are required to establish that they have met their annual Renewable Volume Obligation ("RVO"). Each year, the EPA may adjust the volume of renewable fuels mandated to be blended by refiners, given certain circumstances. The EPA announced on its website in April 2015 that it is developing a proposed consent decree in litigation brought against the Agency by the American Petroleum Institute and the American Fuel and Petrochemical Manufacturers and relating to the establishment of renewable fuel obligations, that would, among other things, require the EPA to finalize volume requirements for 2014 and 2015 by November 30, 2015.

Renewable Identifications Numbers ("RINs") are a mechanism by which Obligated Blenders may demonstrate their compliance with the RVO, whereas the Obligated Blender must produce a volume of RINs equal to the number of gallons that it is required to blend under the RVO. If an Obligated Blender does not blend a sufficient volume of renewable fuel into its production pool each year, it must purchase and/or generate RINs to cover its blending obligation under the RFS. In conjunction with the Partnership's ongoing compliance with the RFS, we will regularly purchase RINs in the open market to cover our anticipated blending obligation. We recognize our outstanding RINs obligation as a balance sheet liability. This liability is marked-to-market on a quarterly basis to reflect the market price of RINs on the last day of each quarter.

During the first quarter 2015, we incurred RFS compliance costs of $7.2 million compared to $7.9 million for the first quarter 2014. For the full year 2015, excluding the potential benefit of small refinery exemptions at one or more of our refineries that might be granted to us by the EPA at a later time, we expect our gross estimated annual RINs obligation, which includes RINs that are required to be secured through either blending or through the purchase of RINs in the open market, to be in the range of 90 million to 100 million RINs, versus 87 million RINs in 2014.

Organic Growth Projects Update

We seek to grow our business through a combination of targeted strategic acquisitions and investments in organic growth projects. In some cases, the acquisitions we complete lead to fresh organic growth opportunities, while in other instances, we seek to capitalize on emerging technologies or inefficient markets through greenfield investments that offer us an opportunity to establish a market leadership position.

During mid-year 2013, we introduced a series of high-return organic growth projects requiring a total capital investment of approximately $640.0 million to $665.0 million between 2013 and the first quarter of 2016. As of March 31, 2015, we have invested more than $530.0 million in these projects. During 2015, we estimate that our total capital investment on growth projects will approximate $210.0 million to $245.0 million.

In April 2015, Calumet and its joint-venture partner, MDU Resources Inc. ("MDU"), commissioned the 20,000 bpd greenfield refinery in Dickinson, North Dakota. We expect to commence the sale of finished products to customers during May 2015.

Between the second quarter 2015 and the first quarter 2016, we intend to complete three organic projects, including each of the following:

Missouri Esters Plant Expansion Project

We have commenced a project designed to double esters production capacity at our Missouri esters plant from 35 million to 75 million pounds per year during the third quarter 2015. Esters are a key base stock used in the aviation, refrigerant and automotive lubricants markets. The current total estimated annual EBITDA contribution from this project is estimated to be $8.0 million to $12.0 million, subject to market conditions.

San Antonio Solvents Project

We have commenced a project that will take a portion of our San Antonio refinery's ultra-low sulfur diesel and jet fuel production and convert it into approximately 3,000 bpd of higher margin solvents that will meet customer requirements for low aromatic content. Solvents production will supplement the refinery's current fuels production slate and will be targeted toward the drilling fluids, paints and coating markets. This project is currently expected to reach completion during the fourth quarter of 2015. The current total estimated annual EBITDA contribution from this project is estimated to be approximately $20.0 million, subject to market conditions.

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Montana Refinery Expansion Project
We continue to make significant progress on a project designed to increase production capacity at our Great Falls, Montana refinery from 10,000 bpd to 25,000 bpd by the first quarter 2016. This project will allow us to capitalize on local access to cost-advantaged Bow River crude oil, while producing additional fuels and refined products for delivery into the regional market. The scope of this project currently includes the installation of a new crude unit that will process 25,000 bpd of crude oil and other feedstocks, in addition to a 25,000 bpd hydrocracker. Presently, all major critical path items have been delivered to the refinery. The current estimated annual EBITDA contribution from this project is $70.0 million to $90.0 million, subject to market conditions.
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 cash distribution, 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.” As of March 31, 2015, we had hedged refining margins, or crack spreads, on approximately 2.2 million barrels of fuel products through the third quarter 2015 at an average refining margin of $17.41 per barrel with average refining margins ranging from a low of $14.31 per barrel in the third quarter 2015 to a high of $17.94 per barrel in the second quarter 2015. Please refer to Note 8 — “Derivatives” under Part I, Item 1 “Financial Statements—Notes to Unaudited Condensed Consolidated Financial Statements” and Part I, Item 3 “Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk” for detailed information regarding our derivative instruments and our commodity price risk.
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; and
•specialty products, fuel products and oilfield services segment Adjusted EBITDA.
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 by-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 in selling prices typically lags behind the rising costs 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.

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Our fuel products segment gross profit 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, operating costs including fixed costs and 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 as Adjusted EBITDA is a component in the calculation of Distributable Cash Flow and allows us to meaningfully analyze the trends and performance of our core cash operations as well as make decisions regarding the allocation of resources to segments.

In addition to the foregoing measures, we also monitor our selling and general and administrative expenses.

Results of Operations for the Three Months Ended March 31, 2015 and 2014

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. The table includes the results of operations of our United Petroleum assets commencing February 28, 2014.

	Three Months Ended March 31,			
	2015	2014	% Change	
	(In bpd)			
Total sales volume [1]	121,444	117,478	3.4	%
Total feedstock runs [2]	120,861	118,359	2.1	%
Facility production: [3]				
Specialty products:				
Lubricating oils	12,090	10,617	13.9	%
Solvents	9,879	8,595	14.9	%
Waxes	1,707	1,321	29.2	%
Packaged and synthetic specialty products [4]	1,491	1,554	(4.1	)%
Other	912	2,507	(63.6	)%
Total	26,079	24,594	6.0	%
Fuel products:				
Gasoline	37,688	32,987	14.3	%
Diesel	30,223	26,795	12.8	%
Jet fuel	5,052	4,428	14.1	%
Asphalt, heavy fuels and other	21,978	22,368	(1.7	)%
Total	94,941	86,578	9.7	%
Total facility production [3]	121,020	111,172	8.9	%

(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 March 31, 2015 compared to the same period in 2014 is due primarily to increased production at the Shreveport refinery due to increased reliability and increased production at the San Antonio refinery as a result of the crude oil unit expansion completed in December 2013 being fully operational.

(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.

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The increase in total feedstock runs for the three months ended March 31, 2015 compared to the same period in 2014 is due primarily to increased production at the Shreveport refinery due to increased reliability and increased production at the San Antonio refinery as a result of the crude oil unit expansion completed in December 2013 being fully operational.

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

The increase in total facility production for the three months ended March 31, 2015 compared to the same period in 2014 is due primarily to the operational items discussed above in footnote 2 of this table.

(4) Represents production of packaged and synthetic specialty products, including 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 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 March 31,	
	2015	2014
	(In millions)	
Sales	$1,018.6	$1,341.0
Cost of sales	823.4	1,216.2
Gross profit	195.2	124.8
Operating costs and expenses:		
Selling	38.4	19.0
General and administrative	39.2	25.9
Transportation	42.0	40.4
Taxes other than income taxes	4.0	2.1
Other	2.9	2.1
Operating income	68.7	35.3
Other income (expense):		
Interest expense	(27.0)	(26.2)
Debt extinguishment costs	—	(89.6)
Realized gain on derivative instruments	8.9	6.6
Unrealized gain (loss) on derivative instruments	(27.9)	24.6
Other	(3.7)	(0.3)
Total other expense	(49.7)	(84.9)
Net income (loss) before income taxes	19.0	(49.6)
Income tax expense (benefit)	(4.8)	0.2
Net income (loss)	$23.8	$(49.8)
EBITDA	$81.4	$96.4
Adjusted EBITDA	$124.9	$82.7
Distributable Cash Flow	$94.1	$49.4

Non-GAAP Financial Measures

We include in this Quarterly Report the non-GAAP financial measures EBITDA, Adjusted EBITDA and Distributable Cash Flow, and provide reconciliations of EBITDA, Adjusted EBITDA and Distributable Cash Flow to net income (loss) and net cash provided by operating activities, our most directly comparable financial performance and liquidity measures calculated and presented in accordance with 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.

We believe 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. We believe that excluding these transactions allows investors to meaningfully analyze trends and performance of our core cash operations.

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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) unrealized losses from mark to market accounting for hedging activities; (e) realized gains under derivative instruments excluded from the determination of net income (loss); (f) 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); (g) debt refinancing fees, premiums and penalties and (h) 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) and income tax expense. 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 and 2023 Notes (as defined in this Quarterly Report). We are required to report Consolidated Cash Flow to the holders of our 2021 Notes, 2022 Notes and 2023 Notes and Adjusted EBITDA to the lenders under our revolving credit facility, and these measures are used by them to determine our compliance with certain covenants governing those debt instruments. Please refer to “Liquidity and Capital Resources” within this item for additional details regarding the covenants governing our debt instruments.

EBITDA, Adjusted EBITDA and Distributable Cash Flow should not be considered alternatives to net income (loss), operating income, net cash provided by operating activities or any other measure of financial performance or liquidity 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 the 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 both net income (loss) to EBITDA, Adjusted EBITDA and Distributable Cash Flow, and Distributable Cash Flow, Adjusted EBITDA and EBITDA to net cash provided by 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 March 31,	
	2015	2014
	(In millions)	
Reconciliation of Net income (loss) to EBITDA, Adjusted EBITDA and Distributable Cash Flow:		
Net income (loss)	$23.8	$(49.8)
Add:		
Interest expense	27.0	26.2
Debt extinguishment costs	—	89.6
Depreciation and amortization	35.4	30.2
Income tax expense (benefit)	(4.8)	0.2
EBITDA	$81.4	$96.4
Add:		
Unrealized (gain) loss on derivative instruments	$27.9	$(24.6)
Realized gain on derivatives, not included in net income (loss)	6.1	1.5
Amortization of turnaround costs	6.1	5.8
Non-cash equity based compensation and other non-cash items	3.4	3.6
Adjusted EBITDA	$124.9	$82.7
Less:		
Replacement and environmental capital expenditures (1)	$7.3	$5.8
Cash interest expense (2)	25.6	24.3
Turnaround costs	2.7	3.0
Income tax expense (benefit)	(4.8)	0.2
Distributable Cash Flow	$94.1	$49.4

(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.

	Three Months Ended March 31,	
	2015	2014
	(In millions)	
Reconciliation of Distributable Cash Flow, Adjusted EBITDA and EBITDA to Net cash provided by operating activities:		
Distributable Cash Flow	$94.1	$49.4
Add:		
Replacement and environmental capital expenditures [1]	7.3	5.8
Cash interest expense [2]	25.6	24.3
Turnaround costs	2.7	3.0
Income tax expense (benefit)	(4.8)	0.2
Adjusted EBITDA	$124.9	$82.7
Less:		
Unrealized (gain) loss on derivative instruments	27.9	(24.6)
Realized gain on derivatives, not included in net income (loss)	6.1	1.5
Amortization of turnaround costs	6.1	5.8
Non-cash equity based compensation and other non-cash items	3.4	3.6
EBITDA	$81.4	$96.4
Add:		
Unrealized (gain) loss on derivative instruments	27.9	(24.6)
Cash interest expense [2]	(25.6)	(24.3)
Non-cash equity based compensation	3.2	3.0
Lower of cost or market inventory adjustment	13.2	(1.3)
Amortization of turnaround costs	6.1	5.8
Income tax (expense) benefit	4.8	(0.2)
Provision for doubtful accounts	—	0.6
Debt extinguishment costs	—	(70.9)
Changes in assets and liabilities:		
Accounts receivable	29.2	(54.1)
Inventories	(18.9)	(50.0)
Other current assets	4.4	5.8
Turnaround costs	(2.7)	(3.0)
Derivative activity	9.2	1.5
Accounts payable	(78.9)	163.2
Accrued interest payable	0.7	(7.4)
Other current liabilities	34.3	(2.0)
Other, including changes in noncurrent liabilities	1.1	1.1
Net cash provided by operating activities	$89.4	$39.6

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

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

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Changes in Results of Operations for the Three Months Ended March 31, 2015 and 2014

Sales. Sales decreased $322.4 million, or 24.0%, to $1,018.6 million in the three months ended March 31, 2015 from $1,341.0 million in the same period in 2014. The results of operations related to the United Petroleum Acquisition has been included in the specialty products segment since its date of acquisition, February 28, 2014. The results of operations related to the Anchor and SOS Acquisitions have been included in the oilfield services segment since their dates of acquisition, March 31, 2014 and August 1, 2014, respectively. Sales for each of our principal product categories in these periods were as follows:

	Three Months Ended March 31,		
	2015	2014	% Change
	(Dollars in millions, except barrel and per barrel data)		
Sales by segment:			
Specialty products:			
Lubricating oils	$149.8	$197.7	(24.2)%
Solvents	86.2	131.4	(34.4)%
Waxes	39.0	35.4	10.2%
Packaged and synthetic specialty products [1]	80.5	76.4	5.4%
Other [2]	6.1	9.1	(33.0)%
Total specialty products	$361.6	$450.0	(19.6)%
Total specialty products sales volume (in barrels)	2,348,000	2,326,000	0.9%
Average specialty products sales price per barrel	$154.00	$193.47	(20.4)%
Fuel products:			
Gasoline	$232.3	$365.3	(36.4)%
Diesel	209.1	324.6	(35.6)%
Jet fuel	36.8	44.2	(16.7)%
Asphalt, heavy fuel oils and other [3]	69.9	170.0	(58.9)%
Hedging activities	20.2	(13.1)	(254.2)%
Total fuel products	$568.3	$891.0	(36.2)%
Total fuel products sales volume (in barrels)	8,582,000	8,247,000	4.1%
Average fuel products sales price per barrel (excluding hedging activities)	$63.87	$109.63	(41.7)%
Average fuel products sales price per barrel (including hedging activities)	$66.22	$108.04	(38.7)%
Total oilfield services	$88.7	$—	—
Total sales	$1,018.6	$1,341.0	(24.0)%
Total specialty and fuel products sales volume (in barrels)	10,930,000	10,573,000	3.4%

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

(2) Represents by-products, including 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 Montana refineries and purchased crude oil sales from the Superior refinery to third party customers.

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The components of the $88.4 million specialty products segment sales decrease in the three months ended March 31, 2015 were as follows:

	Dollar Change (In millions)
Sales Price	$(92.0)
Volume	(0.6)
Acquisition	4.2
Total specialty products segment sales decrease	$(88.4)

Specialty products segment sales decreased $88.4 million period over period, or 19.6%, primarily due to a decrease in the average selling price per barrel, partially offset by $4.2 million of incremental sales from the United Petroleum Acquisition. Legacy operations' sales decreased $92.0 million compared to the first quarter 2014 due to a 20.5% decrease in the average selling price per barrel primarily as a result of decreased lubricating oil and solvent sales prices, while the average cost of crude oil per barrel decreased 49.2%. Legacy operations' sales volumes remained relatively consistent.

The components of the $322.7 million fuel products segment sales decrease for the three months ended March 31, 2015 were as follows:

	Dollar Change (In millions)
Sales price	$(392.7)
Volume	36.7
Hedging activities	33.3
Total fuel products segment sales decrease	$(322.7)

Fuel products segment sales decreased $322.7 million period over period, or 36.2%, primarily due to a decrease in the average selling price per barrel, partially offset by increased sales volume and a $33.3 million decrease in realized derivative losses recorded in sales on our fuel products cash flow hedges. The average selling price per barrel (excluding the impact of hedging activities reflected in sales) decreased $45.76, or 41.7%, resulting in a $392.7 million decrease in sales, compared to a 50.5% 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 4.1% primarily due to increased sales volume of gasoline, diesel and jet fuel, as a result of increased production at our Shreveport refinery due to increased reliability in the 2015 period and increased production at the San Antonio refinery as a result of the crude oil unit expansion completed in December 2013 being fully operational, partially offset by decreased crude oil sales to third parties.

Oilfield services segment sales for the three months ended March 31, 2015 increased $88.7 million as a result of the Anchor and SOS Acquisitions in 2014. Volatility in crude oil and natural gas prices impacted our customers' drilling and production activities during 2015, which resulted in an unfavorable impact to our sales in 2015. The U.S. onshore rig count decreased 43% from the fourth quarter of 2014 to the first quarter of 2015. Currently, we sell to approximately 10% of the U.S. land based rigs.

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Gross Profit. Gross profit increased $70.4 million, or 56.4%, to $195.2 million in the three months ended March 31, 2015 from $124.8 million in the same period in 2014. Gross profit for our specialty, fuel products and oilfield services segments were as follows:

	Three Months Ended March 31,		
	2015	2014	% Change
	(Dollars in millions, except per barrel data)		
Gross profit by segment:			
Specialty products:			
Gross profit	$100.2	$98.2	2.0 %
Percentage of sales	27.7 %	21.8 %	
Specialty products gross profit per barrel	$42.67	$42.22	1.1 %
Fuel products:			
Gross profit excluding hedging activities	$69.5	$30.2	130.1 %
Hedging activities	(1.3)	(3.6)	(63.9)%
Gross profit	$68.2	$26.6	156.4 %
Percentage of sales	12.0 %	3.0 %	
Fuel products gross profit per barrel (excluding hedging activities)	$8.10	$3.66	121.3 %
Fuel products gross profit per barrel (including hedging activities)	$7.95	$3.23	146.1 %
Oilfield services:			
Gross profit	$26.8	$—	
Percentage of sales	30.2 %	— %	—
Total gross profit	$195.2	$124.8	56.4 %
Percentage of sales	19.2 %	9.3 %	

The components of the $2.0 million specialty products segment gross profit increase for the three months ended March 31, 2015 were as follows:

	Dollar Change
	(In millions)
Three months ended March 31, 2014 reported gross profit	$98.2
Cost of materials	114.5
Operating costs	2.4
Acquisition	1.0
Sales price	(92.0)
LCM inventory adjustment	(23.7)
Volume	(0.2)
Three months ended March 31, 2015 reported gross profit	$100.2

The increase in specialty products segment gross profit of $2.0 million for the three months ended March 31, 2015 compared to the same period in 2014 was due primarily to decreased cost of materials, partially offset by decreased sales price per barrel and a $23.7 million unfavorable LCM inventory adjustment as a result of decreased selling prices. Sales price and cost of materials, net, from our legacy operations increased gross profit by $22.5 million, as the average selling price per barrel decreased 20.5%, while the average cost of crude oil per barrel decreased 49.2%.

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The components of the $41.6 million fuel products segment gross profit increase for the three months ended March 31, 2015 were as follows:

	Dollar Change (In millions)	
Three months ended March 31, 2014 reported gross profit	$26.6	
Cost of materials	417.1	
LCM inventory adjustment	9.2	
Volume	4.7	
Hedging activities	2.3	
Operating costs	1.0	
Sales price	(392.7	)
Three months ended March 31, 2015 reported gross profit	$68.2	

The increase in fuel products segment gross profit of $41.6 million for the three months ended March 31, 2015 compared to the same period in 2014 was due primarily to widening crack spreads, a $9.2 million favorable LCM inventory adjustment and a $2.3 million decrease in realized losses on derivatives. During the 2015 period, crack spreads widened as the average cost of crude oil per barrel decreased 50.5% and the average selling price per barrel decreased by 41.7%. The $9.2 million favorable LCM inventory adjustment resulted from a decrease in inventory levels and improved gasoline pricing.

The increase in oilfield services segment gross profit of $26.8 million year over year was due to the Anchor and SOS Acquisitions in 2014. Volatility in crude oil and natural gas prices impacted our customers' drilling and production activities, which resulted in an unfavorable impact to our gross profit in 2015. The continued decrease in crude oil prices created tighter market conditions, in the basins in which we operate.

Selling. Selling expenses increased $19.4 million, or 102.1%, to $38.4 million in the three months ended March 31, 2015 from $19.0 million in the same period in 2014. The increase was due primarily to incremental selling expenses related to the Anchor and SOS Acquisitions.

General and administrative. General and administrative expenses increased $13.3 million, or 51.4%, to $39.2 million in the three months ended March 31, 2015 from $25.9 million in the same period in 2014. The increase was due primarily to incremental general and administrative expenses related to the Anchor and SOS Acquisitions, $7.2 million legal matters reserve, $1.7 million in severance expenses and a $1.5 million increase in professional fees expense.

Transportation. Transportation expenses increased $1.6 million, or 4.0%, to $42.0 million in the three months ended March 31, 2015 from $40.4 million in the same period in 2014. This increase was due primarily to incremental transportation expenses related to the Anchor and SOS Acquisitions, partially offset by decreased crude oil sales to third parties and decreased freight rates.

Interest expense. Interest expense increased $0.8 million, or 3.1%, to $27.0 million in the three months ended March 31, 2015 from $26.2 million in the same period in 2014, due primarily to additional outstanding long-term debt in the form of 2023 Notes and 2021 Notes, partially offset by the redemption of the 2019 Notes.

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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 March 31, 2015 and 2014:

	Three Months Ended March 31,	
	2015	2014
	(In millions)	
Derivative gain (loss) reflected in sales	$20.2	$(13.1)
Derivative gain (loss) reflected in cost of sales	(21.9)	9.2
Derivative losses reflected in gross profit	$(1.7)	$(3.9)
Realized gain on derivative instruments	$8.9	$6.6
Unrealized gain (loss) on derivative instruments	(27.9)	24.6
Derivative gain reflected in interest expense	0.2	0.3
Total derivative gain (loss) reflected in the unaudited condensed consolidated statements of operations	$(20.5)	$27.6
Total gain on commodity derivative settlements	$13.3	$4.2

Realized gain on derivative instruments. Realized gain on derivative instruments increased $2.3 million to $8.9 million in the three months ended March 31, 2015 from $6.6 million in the prior period. The change was due primarily to increased realized gains of approximately $11.4 million related to settlements of derivative instruments used to economically hedge crack spreads that are not classified as hedges for accounting purposes, partially offset by increased realized losses of $4.2 million related to ineffectiveness on settlements of cash flow hedges and increased realized losses of approximately $3.0 million on natural gas swaps used to economically hedge natural gas purchases.

Unrealized gain (loss) on derivative instruments. Unrealized gain (loss) on derivative instruments decreased $52.5 million to a loss of $27.9 million in the three months ended March 31, 2015 from a gain of $24.6 million in the prior period. The change is due primarily to decreased unrealized gains of approximately $39.0 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 and decreased gain ineffectiveness of approximately $13.4 million.

Income tax expense (benefit). Income tax expense (benefit) decreased $5.0 million to a benefit of $4.8 million in the three months ended March 31, 2015 from an expense of $0.2 million in the prior year period. The change was due primarily to the Anchor Acquisition, which increased the proportion of earnings 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 of the year.

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 2014 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 5— “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 our joint venture with MDU and our Juniper joint venture.

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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. We expect that our principal uses of cash in the future will be for distributions to our unitholders and general partner, debt service, replacement and environmental capital expenditures, capital expenditures related to internal growth projects and acquisitions from third parties or affiliates.

We expect to fund future capital expenditures with current cash flow from operations, borrowings under our revolving credit facility and by accessing capital markets as necessary. Future internal growth projects or acquisitions may require expenditures in excess of our then-current cash flow from operations and borrowing availability under our existing revolving credit facility and may require us to issue debt or equity securities in public or private offerings or incur additional borrowings under bank credit facilities to meet those costs.

Cash Flows from Operating, Investing and Financing Activities

We believe that we have sufficient liquid assets, cash flow from operations, borrowing capacity and adequate access to capital markets to meet our financial commitments, debt service obligations and anticipated capital expenditures. However, 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 income (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:

	Three Months Ended March 31,	
	2015	2014
	(In millions)	
Net cash provided by operating activities	$89.4	$39.6
Net cash used in investing activities	(99.0)	(309.3)
Net cash provided by financing activities	273.9	328.2
Net increase in cash and cash equivalents	$264.3	$58.5

Operating Activities. Cash provided by operating activities increased to $89.4 million during the three months ended March 31, 2015 compared to $39.6 million during the same period in 2014. The change is due primarily to increased net income of $73.6 million, partially offset by increased working capital requirements, primarily from lower accounts payable.

Investing Activities. Cash used in investing activities decreased to $99.0 million during the three months ended March 31, 2015 compared to $309.3 million during the prior year period. The decrease is due primarily to the combined purchase price of $247.0 million for the Anchor, United Petroleum and SOS Acquisitions, which closed in 2014, with no similar activity in 2015, partially offset by an increase in capital expenditures of $27.8 million due primarily to the capital improvement projects discussed below and an increase in joint venture investments of $9.0 million related to contributions to the Dakota Prairie and Juniper joint ventures (both defined below).

Financing Activities. Financing activities provided cash of $273.9 million in the three months ended March 31, 2015 compared to $328.2 million during the prior year period. This decrease is due primarily to decreased net proceeds from the private placement of senior notes of $567.1 million and repayments of revolving credit facility borrowings of $150.7 million. Partially offsetting these decreases are the redemption of the 2019 Notes of $500.0 million in the 2014 period and an increase in net proceeds from public offerings of common units (including our general partner's contributions) of $165.2 million.

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Acquisitions

Acquisitions impact our results of operations commencing on the closing date of each acquisition. Our acquisitions are discussed further in Note 3 of Part I, Item 1 "Financial Statements—Acquisitions". Information regarding acquisitions completed during 2014 is set forth in the table below (in millions):

Acquisition	Closing Date	Purchase Price	Funding Method	Segment
United Petroleum	February 28, 2014	$10.4	Cash on hand	Specialty Products
Anchor	March 31, 2014	223.6	Net proceeds from March 2014 private placement of 2021 Notes	Oilfield Services
SOS	August 1, 2014	29.6	Borrowings under revolving credit facility	Oilfield Services
2014 Total		$263.6		

Joint Ventures

On February 7, 2013, we entered into a joint venture agreement with MDU to develop, build and operate a diesel refinery in southwestern North Dakota. The joint venture is named Dakota Prairie Refining, LLC ("Dakota Prairie"). The capitalization of the joint venture is expected to be funded through contributions of $217.5 million from MDU and a total of $217.5 million from us comprised of $142.5 million through cash contributions and proceeds of $75.0 million from an unsecured syndicated term loan facility with the joint venture as the borrower which is expected to be repaid by us through our allocation of profits from the joint venture. The term loan facility was funded in April 2013. The joint venture allocates profits on a 50%/50% basis to us and MDU. The joint venture is governed by a board of managers comprised of representatives from both us and MDU. MDU is providing a portion of the crude oil supply to the refinery, as well as natural gas and electricity utility services. We are providing refinery operations, crude oil procurement and refined product marketing expertise to the joint venture. Dakota Prairie reached mechanical completion and was commissioned in April 2015. Dakota Prairie is expected to commence sales of finished products in May 2015. As of March 31, 2015 and December 31, 2014, we had an investment of $133.3 million and $117.2 million, respectively, in Dakota Prairie primarily related to the development of the refinery.

On June 9, 2014, we entered into a joint venture agreement with Clean Fuels North America, LLC, which is owned by SGC Energia and Great Northern Project Development, to develop, build and operate a gas-to-liquids ("GTL") plant in Lake Charles, Louisiana, which is expected to be operational by late 2015. The joint venture is named New Source Fuels, LLC, and it owns 100% of Juniper GTL LLC ("Juniper"). The capitalization of the joint venture is expected to be funded through $100.0 million of equity contributions and $35.0 million in senior secured debt with the joint venture as the borrower. We intend to invest $25.0 million in total in exchange for an equity interest of approximately 23% in the joint venture. Funding of the project will occur over the course of the construction period. The joint venture is governed by a board of managers comprised of representatives from all of the members that own at least 10% of the equity in Juniper. As of March 31, 2015 and December 31, 2014, we had an investment of $23.0 million and $18.5 million, respectively, in Juniper, primarily related to the development of the plant.

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:

	Three Months Ended March 31,	
	2015	2014

	(In millions)	
Capital improvement expenditures	$75.4	$43.8
Replacement capital expenditures	5.2	3.2
Environmental capital expenditures	2.1	2.6
Turnaround capital expenditures	2.7	3.0
Joint venture contributions	25.0	16.0
Total	$110.4	$68.6

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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.

We estimate our replacement and environmental capital expenditures will be approximately $60.0 million to $70.0 million for 2015. These estimated amounts for 2015 include a portion of the $9.0 million to $11.0 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 have several capital improvement projects underway including capacity expansions at certain of our facilities, as well as active investments, such as the Dakota Prairie joint venture with MDU. Collectively, these projects are estimated to cost approximately $640.0 million to $665.0 million. We estimate we will spend approximately $210.0 million to $245.0 million in 2015 on capital investment in growth projects. Our primary capital improvements projects include the following:

- Montana Refinery Expansion - We plan to increase our Montana refinery's crude oil throughput capacity from 10,000 bpd to 25,000 bpd ("Montana Refinery Expansion"). The incremental production slate will consist primarily of gasoline, diesel, jet fuel and diluent, all of which will be sold into regional markets. We anticipate the total cost of the Montana Refinery Expansion to be approximately $400.0 million, with expected completion by the first quarter of 2016.
- Dakota Prairie Refining, LLC - We have entered into a joint venture agreement with MDU to develop, build and operate a 20,000 bpd diesel refinery in southwestern North Dakota. Please read — "Joint Ventures" above for additional information.

During the three months ended March 31, 2015, we spent approximately $2.7 million primarily related to scheduled turnaround activities at our Princeton refinery funded through cash flow from operations. Additionally, we estimate turnaround spending requirements will be $15.0 million to $20.0 million for 2015 primarily related to scheduled turnaround activity at our Shreveport, Princeton and San Antonio refineries. We expect these expenditures will be funded primarily through cash flow from operations.

Debt and Credit Facilities

As of March 31, 2015, 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 (as defined in the revolving credit agreement) ("revolving credit facility");
- $275.0 million of 9.625% senior notes due 2020 ("2020 Notes");
- $900.0 million of 6.50% senior notes due 2021 ("2021 Notes");
- $350.0 million of 7.625% senior notes due 2022 ("2022 Notes"); and
- $325.0 million of 7.75% senior notes due 2023 ("2023 Notes").

On April 27, 2015, we redeemed $96.2 million aggregate principal amount of 2020 Notes with a portion of the net proceeds of the March 13, 2015 public offering of our common units in which we sold 6,000,000 common units. Additionally, on April 28, 2015, we redeemed the remaining $178.8 million aggregate principal amount of 2020 Notes with a portion of the net proceeds from the issuance of the 2023 Notes.

We were in compliance with all covenants under the debt instruments in place as of March 31, 2015 and believe we have adequate liquidity to conduct our business.

Short Term Liquidity

As of March 31, 2015, our principal sources of short-term liquidity were (i) $497.6 million of availability under our revolving credit facility and (ii) $272.8 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. In April 2015, we redeemed all of $275.0 million aggregate principal amount of 2020 Notes.

Borrowings under the revolving credit facility are limited to a borrowing base that is determined based on advance rates of percentages of Eligible Accounts Receivable and Eligible Inventory (as defined in the revolving credit agreement). As such,

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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 March 31, 2015, we had availability on our revolving credit facility of $497.6 million, based on a $563.0 million borrowing base, $65.3 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 supplies on the 20th day of every month per standard industry terms. The maximum revolving credit facility borrowings during the quarter ended March 31, 2015 were $269.2 million. Our availability on our revolving credit facility during the peak borrowing days of the quarter has been ample to support our operations and service upcoming requirements. During the quarter ended March 31, 2015, availability for additional borrowings under our revolving credit facility was approximately $264.0 million at its lowest point.

The revolving credit facility currently bears interest at a rate equal to prime plus a basis points margin or LIBOR plus a basis points margin, at our option. As of March 31, 2015, this margin was 75 basis points for prime and 175 basis points for LIBOR; however, the margin can fluctuate quarterly based on our average availability for additional borrowings under the revolving credit facility in the preceding calendar 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 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. 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, we will be required to maintain as of the end of each fiscal quarter a Fixed Charge Coverage Ratio (as defined in the 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.

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, we can 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 are unsecured obligations that rank equally with all of our other senior debt obligations to the extent they are unsecured. As of March 31, 2015, we had $275.0 million in 2020 Notes, $900.0 million in 2021 Notes, $350.0 million in 2022 Notes and $325.0 million in 2023 Notes outstanding. As of December 31, 2014, we had $275.0 million in 2020 Notes, $900.0 million in 2021 Notes and $350.0 million in 2022 Notes outstanding. In April 2015, we redeemed all of the $275.0 million aggregate principal amount of 2020 Notes.

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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 its subordinated debt; (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 Standard & Poor’s Ratings Services (“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 and, except in the case of the 2020 Notes, an investment grade rating is required from both Moody’s and S&P. As of March 31, 2015, our Fixed Charge Coverage Ratio (as defined in the indentures governing the 2020, 2021, 2022 and 2023 Notes) was 2.7 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 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 2014 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 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 March 31, 2015. Our master derivatives contracts and Collateral Trust Agreement (as defined below) 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 March 31, 2015 did not materially change subsequent to March 31, 2015. 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 secured hedging counterparties will share collateral pledged as security for the payment obligations owed by us to secured hedging counterparties under their respective master derivatives contracts. The Collateral Trust Agreement limits to $100.0 million the extent to which forward purchase contracts for physical commodities are covered by, and secured under, 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.

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Equity Transactions

On March 13, 2015, we completed a public offering of our common units in which we sold 6,000,000 common units to the underwriters of the offering at a price to the public of $26.75 per unit. The proceeds received by us from this offering (net of underwriting discounts, commissions and expenses but before our general partner's capital contribution) were approximately $154.0 million and were used to redeem a portion of the 2020 Notes and to repay borrowings under our revolving credit facility. Underwriting discounts totaled approximately $6.4 million. Our general partner contributed $3.3 million to maintain its 2% general partner interest.

We have entered into an Equity Placement Agreement with various sales agents under which we may issue and sell, 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 provides us the right, but not the obligation, to sell common units in the future, at prices we deem appropriate. These sales, if any, will be made pursuant to the terms of the Equity Placement Agreement between us and the sales agents. The net proceeds from any sales under this agreement will be used for general partnership purposes, which may include, among other things, repayment of indebtedness, working capital, capital expenditures and acquisitions. Our general partner contributed its proportionate capital contribution to retain its 2% general partner interest. For the three months ended March 31, 2015, we sold 307,985 common units for net proceeds of approximately$7.7 million. Underwriting discounts totaled approximately $0.1 million and our general partner contributed approximately $0.2 million to maintain its general partner interest.

During 2015, we have made, or expect to make, 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, 2014	January 23, 2015	February 3, 2015	February 13, 2015	$ 0.685	$ 52.7	$ 2.74	$ 210.8
March 31, 2015	April 20, 2015	May 5, 2015	May 15, 2015	$ 0.685	$ 57.3	$ 2.74	$ 229.2

Contractual Obligations and Commercial Commitments

A summary of our total contractual cash obligations as of March 31, 2015 at current maturities and reflecting only those line items that have materially changed since December 31, 2014 is as follows:

	Total	Payments Due by Period			
		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)	$885.5	$116.9	$240.5	$237.5	$290.6
Debt extinguishment costs (2)	37.5	37.5	—	—	—
Operating lease obligations (3)	172.5	38.6	61.7	39.7	32.5
Letters of credit (4)	65.3	65.3	—	—	—
Purchase commitments (5)	1,172.5	785.6	212.1	174.8	—
Employment agreements	3.7	3.3	0.4	—	—
Investing activities:					
Investment in unconsolidated affiliates	8.5	8.5	—	—	—
Financing activities:					
Capital lease obligations	43.5	0.6	1.4	1.7	39.8
Long-term debt obligations, excluding capital lease obligations	1,850.1	275.0	—	0.1	1,575.0
Total obligations	$4,239.1	$1,331.3	$516.1	$453.8	$1,937.9

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(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. In addition, interest on long-term debt at contractual rates and maturities excludes interest on 2020 Notes subsequent to April 2015 as a result of the early redemption.

(2) Debt extinguishment costs relate to the redemption of $275.0 million of aggregate principal amount of 2020 Notes in April 2015.

(3) 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 April 2027.

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

(5) Purchase commitments consist primarily of obligations to purchase fixed volumes of crude oil, other feedstocks, finished products for resale and renewable fuels 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 $39.7 million of feedstock for the LVT unit in each fiscal year of the term based on pricing estimates as of March 31, 2015. This amount is not included in the table above.

For additional information regarding our expected capital and turnaround expenditures for the remainder of 2015, 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 months ended March 31, 2015.

Critical Accounting Policies and Estimates

For additional discussion regarding our critical accounting policies and estimates, see “Critical Accounting Policies and Estimates” under Part II, Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations” of our 2014 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 2014 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 and options, 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 the implied crack spreads for our crude oil and gasoline fuel swaps on a combined basis as of March 31, 2015 in our fuel products segment:

Crude Oil and Gasoline Swap Contracts by Expiration Dates	Barrels	BPD	Implied Crack Spread ($/Bbl)
Second Quarter 2015	1,849,000	20,319	$17.94
Third Quarter 2015	322,000	3,500	$14.31
Totals	2,171,000		
Average price			$17.41

We entered into crack spread derivative instruments to secure a fixed percentage of gross profit on diesel in excess of the floating value of NYMEX WTI crude oil. The following table provides a summary of diesel percent basis crack spread swap contracts as of March 31, 2015 in our fuel products segment:

Diesel Percent Basis Crack Spread Swap Contracts by Expiration Dates	Barrels Sold	BPD	Fixed Percentage of NYMEX WTI (Average % of WTI/Bbl)	
Third Quarter 2015	506,000	5,500	33.1	%
Fourth Quarter 2015	506,000	5,500	33.1	%
Calendar Year 2016	2,196,000	6,000	31.8	%
Total	3,208,000			
Average percentage			32.2	%

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The following table provides a summary of crude oil percent basis swap contracts related to crude oil purchases as of March 31, 2015 in our fuel products segment:

Crude Oil Percent Basis Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Fixed Percentage of NYMEX WTI (Average % of WTI/Bbl)	
Third Quarter 2015	184,000	2,000	73.0	%
Fourth Quarter 2015	184,000	2,000	73.0	%
Calendar Year 2016	732,000	2,000	75.0	%
Total	1,100,000			
Average percentage			74.3	%

During the first quarter of 2015, we 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 options as of March 31, 2015 in our fuel products segment:

Crude Oil Option Contracts by Expiration Dates	Barrels Purchased and Sold	BPD	Average Bought Put ($/Bbl)	Average Sold Call ($/Bbl)
Second Quarter 2015	1,000,000	10,989	$48.00	$—
Fourth Quarter 2015	500,000	5,435	$—	$70.00
Total	1,500,000			
Average price			$48.00	$70.00

The following table provides a summary of natural gas swaps as of March 31, 2015 in our fuel products segment:

Natural Gas Swap Contracts by Expiration Dates	MMBtu	$/MMBtu
Calendar Year 2016	1,320,000	$3.38
Total	1,320,000	
Average price		$3.38

The following table provides a summary of natural gas swaps as of March 31, 2015 in our specialty products segment:

Natural Gas Swap Contracts by Expiration Dates	MMBtu	$/MMBtu
Second Quarter 2015	1,500,000	$4.11
Third Quarter 2015	1,500,000	$4.11
Fourth Quarter 2015	1,900,000	$4.12
Calendar Year 2016	5,880,000	$4.22
Calendar Year 2017	4,950,000	$3.85
Totals	15,730,000	
Average price		$4.07

The following table provides a summary of natural gas collars as of March 31, 2015 in our specialty products segment:

Natural Gas Collars by Expiration Dates	MMBtu	Average Bought Call ($/MMBtu)	Average Sold Put ($/MMBtu)
Second Quarter 2015	240,000	$4.25	$3.79
Third Quarter 2015	240,000	$4.25	$3.79
Fourth Quarter 2015	200,000	$4.25	$3.85
Calendar Year 2016	600,000	$4.25	$3.89
Total	1,280,000		
Average price		$4.25	$3.84

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Please read Note 8 — "Derivatives" in the notes to our unaudited condensed consolidated financial statements under Part I, Item 1 "Financial Statements and Footnotes" for a discussion of the accounting treatment for the various types of derivative instruments, and a further discussion of our hedging policies and more information relating to our implied crack spreads of crude oil, diesel, gasoline and jet fuel derivative instruments.

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 required. 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 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 March 31, 2015:

	In millions
Crude oil swaps	$2.4
Crude oil percent basis swaps	$1.1
Diesel swaps	$(1.0)
Diesel percent basis crack spread swaps	$(3.2)
Gasoline swaps	$(1.2)
Gasoline crack spread swaps	$(1.0)
Natural gas swaps	$17.1
Natural gas collars	$1.3

Compliance Price Risk

Renewable Identification Numbers

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

Holding other variables constant (RINs requirements), a $1.00 change in the price of RINs as of March 31, 2015 would be expected to have an impact on net income for 2015 of approximately $90 million to $100 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 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 March 31, 2015 and December 31, 2014, 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."

	March 31, 2015		December 31, 2014	
	Fair Value	Carrying Value	Fair Value	Carrying Value
	(In millions)			
Financial Instrument:				
2020 Notes	$310.1	$271.4	$290.5	$271.3
2021 Notes	$873.0	$900.0	$803.3	$900.0
2022 Notes	$351.8	$348.5	$339.5	$347.8
2023 Notes	$330.3	$322.6	$—	$—

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 March 31, 2015, 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 $150.8 million of variable rate debt as of March 31, 2015 and December 31, 2014, respectively. Holding other variables constant (such as debt levels), a 100 basis point change in interest rates on our variable rate debt as of March 31, 2015 would not have a material impact on net income and cash flows for the 2015 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.

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 (the “Exchange Act”), as amended, 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 March 31, 2015 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 first quarter of 2015 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

On March 31, 2014 and August 1, 2014, we completed the Anchor and SOS Acquisitions, respectively, which include certain existing information systems and internal controls over financial reporting. We are currently in the process of evaluating and integrating Anchor and SOS Acquisitions’ historical internal controls over financial reporting with ours. We expect to complete the integration of the Anchor and SOS Acquisitions in fiscal year 2015.

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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 risk factor set forth below, you should carefully consider the risk factors discussed in Part I, Item 1A "Risk Factors" in our 2014 Annual Report, which could materially affect our business, financial condition or future results. The risks described in this Quarterly Report and in our 2014 Annual Report are not the only risks facing the Company. 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 2014 Annual Report other than with respect to the risk factor discussed below.

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes. Proposed regulations made public by the U.S. Treasury Department and the IRS on May 5, 2015 may affect certain of our activities.

Despite the fact that we are organized as a limited partnership under Delaware law, we would be treated as a corporation for U.S. federal income tax purposes unless we satisfy a "qualifying income" requirement (the "Qualifying Income Exception"). Failing to meet the Qualifying Income Exception would cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to taxation as an entity.

We have requested and obtained a number of favorable private letter rulings (the "Rulings") from the IRS to the effect that certain parts of our businesses generate income from the refining, processing, and marketing of petroleum and petroleum products that is treated as "qualifying income" within the meaning of Section 7704 of the Internal Revenue Code of 1986, as amended (the "Code").

On May 5, 2015, the U.S. Treasury Department and the IRS issued proposed regulations (the "Proposed Regulations") regarding qualifying income under Section 7704(d)(1)(E) of the Code. The Proposed Regulations provide industry-specific rules regarding the Qualifying Income Exception, including whether an activity constitutes the processing or refining of a natural resource. The U.S. Treasury Department and the IRS have requested comments from industry participants regarding the standards set forth in the Proposed Regulations.

We believe that our Rulings are largely consistent with the Proposed Regulations, and we anticipate participating in the comment process in order to confirm that the final regulations are consistent with our Rulings. However, the Proposed Regulations, once issued in final form, have the potential to change the law. Any changes to current law could negatively impact the value of an investment in our common units.

Our business involves the shipping by rail of crude oil including from the Bakken Shale, which involves risks of derailment, accidents and liabilities associated with cleanup and damages, as well as regulatory changes that may adversely impact our business, financial condition or results of operations.

Our operations involve the purchasing of crude oil including from the Bakken Shale and shipping it by rail to various markets on rail cars that we lease. Recent derailments of trains transporting crude oil in the U.S. and Canada have caused various regulatory agencies and industry organizations, as well as federal, state and municipal governments, to focus attention on transportation of flammable materials by rail. Transportation safety regulators in the U.S. and Canada are concerned that crude oil from the Bakken Shale may be more flammable than crude oil from other producing regions and are investigating that issue. In May 2015, the Pipeline and Hazardous Materials Safety Administration ("PHMSA") adopted a final rule that, among other things, imposes a new tank car design standard, a phase out by as early as January 2018 for older DOT-111 tank cars that are not retrofitted, and a classification and testing program for unrefined petroleum based products, including crude oil. The rule also includes new operational requirements such as speed restrictions. Transport Canada has also issued new regulations that align with the U.S. rule in many respects.

We are currently reviewing the final rule in detail to assess the expected impact on our business, including the potential impact on the tank cars that we lease to transport our products. We are unable to predict what impact these or other regulatory changes may have, if any, on our business or the industry as a whole. As a result of the final rule, certain of our tank cars that we lease could be deemed unfit for further commercial use or require retrofits or modifications, and the costs associated with any required retrofits or modifications could be substantial. In addition, the new tank car design requirements may result in significant

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constraints on transportation capacity during the period while tank cars are being retrofitted or newly constructed to comply with the new regulations. Such transportation capacity constraints could increase the cost of transporting crude oil by rail. We cannot assure that costs incurred to comply with any new standards and regulations, including those finalized by PHMSA in May 2015, will not be material to our business, financial condition or results of operations. In addition, any derailment involving crude oil that we have purchased or are shipping may result in claims being brought against us that may involve significant liabilities. Although we believe that we are adequately insured against such events, we cannot assure you that our policies will cover the entirety of any damages that may arise from such an event.

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

	Total Number of Common Units Purchased	Average Price Paid per Common Unit	Total Number of Common Units Purchased as a Part of Publicly Announced Plans	Maximum Number of Common Units that May Yet be Purchased Under Plans
January 1, 2015 - January 31, 2015	—	$—	—	—
February 1, 2015 - February 28, 2015	—	—	—	—
March 1, 2015 - March 31, 2015	185,908	25.83	—	—
Total	185,908	$25.83	—	—

(1) A total of 185,908 common units were purchased by our general partner, Calumet GP, LLC, related to the Calumet GP, LLC Long-Term Incentive Plan (the “LTIP”) at an average price per common unit of $25.83 for total consideration of approximately $4.8 million. The purchase and sale of these common units was exempt from registration under Section 4(a)(2) of the Securities Act. The LTIP provides for the delivery of up to 783,960 common units to satisfy awards of phantom units, restricted units or unit options to the employees, consultants or directors of the Company. Such units may be newly issued by the Company or purchased in the open market. None of the common units were purchased pursuant to publicly announced plans or programs. The common units were purchased through a single broker in open market transactions. For more information on the LTIP, refer to Part III, Item 11 “Executive and Director Compensation — Compensation Discussion and Analysis — Elements of Executive Compensation — Long-Term, Unit-Based Awards” in our 2014 Annual Report.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

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Item 6. Exhibits

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

Exhibit Number	Description
3.1	Certificate of Limited Partnership of Calumet Specialty Products Partners, L.P. (incorporated by reference to Exhibit 3.1 to the Registrant's Registration Statement on Form S-1 filed with the Commission on October 7, 2005 (File No. 333-128880)).
3.2	Amended and Restated Limited Partnership Agreement of Calumet Specialty Products Partners, L.P. (incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the Commission on February 13, 2006 (File No. 000-51734)).
3.3	Amendment No. 1 to the First Amended and Restated Agreement of Limited Partnership of Calumet Specialty Products Partners, L.P. (incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the Commission on July 11, 2006 (File No. 000-51734)).
3.4	Amendment No. 2 to First Amended and Restated Agreement of Limited Partnership of Calumet Specialty Products Partners, L.P. (incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the Commission on April 18, 2008 (File No. 000-51734)).
3.5	Certificate of Formation of Calumet GP, LLC (incorporated by reference to Exhibit 3.3 of Registrant's Registration Statement on Form S-1 filed with the Commission on October 7, 2005 (File No. 333-128880)).
3.6	Amended and Restated Limited Liability Company Agreement of Calumet GP, LLC (incorporated by reference to Exhibit 3.2 to the Registrant's Current Report on Form 8-K filed with the Commission on February 13, 2006 (File No. 000-51734)).
4.1	Indenture dated March 27, 2015, by and among the Issuers, the Guarantors and the Trustee relating to the offering of the 2023 Notes (incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the Commission on March 30, 2015 (File No. 000-51734)).
4.2	Form of 7.75% Senior Notes due 2023 (included in Exhibit 4.1 and incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed with the Commission on March 30, 2015 (File No. 000-51734)).
4.3	Registration Rights Agreement, dated March 27, 2015, by and among the Issuers, the Guarantors and the Initial Purchasers, relating to the offering of the 2023 Notes (incorporated by reference to Exhibit 4.3 to the Registrant's Current Report on Form 8-K filed with the Commission on March 30, 2015 (File No. 000-51734)).
10.1*	Employment Agreement, effective as of April 1, 2015, by and between Calumet GP, LLC and William H. Hatch.
31.1*	Sarbanes-Oxley Section 302 certification of William H. Hatch.
31.2*	Sarbanes-Oxley Section 302 certification of R. Patrick Murray, II.

32.1**	Section 1350 certification of William H. Hatch 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

*	Filed herewith.
**	Furnished herewith.

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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: May 8, 2015

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

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)).
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