Calumet Specialty Products Partners, L.P.
Form 10-Q
November 07, 2014

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 SEPTEMBER 30, 2014
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	37-1516132
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification Number)

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Registration S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x

At November 7, 2014, there were 69,452,233 common units outstanding.

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CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
QUARTERLY REPORT
For the Three and Nine Months Ended September 30, 2014
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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, (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”) and (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, 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, 2013 (“2013 Annual Report”), (ii) Part II, Item 1A “Risk Factors” in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2014 (“Q1 Quarterly Report”), (iii) Part II, Item 1A “Risk Factors” in our Quarterly Report on Form 10-Q for the quarter ended June 30, 2014 (“Q2 Quarterly Report”) and (iv) 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

	September 30, 2014 (Unaudited)	December 31, 2013
	(In millions, except unit data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$7.7	$121.1
Accounts receivable:		
Trade	452.1	250.3
Other	9.5	13.0
	461.6	263.3
Inventories	640.5	567.4
Derivative assets	54.8	—
Prepaid expenses and other current assets	20.8	18.9
Deposits	6.1	3.7
Deferred income taxes	0.9	—
Total current assets	1,192.4	974.4
Property, plant and equipment, net	1,385.2	1,160.4
Investment in unconsolidated affiliates	94.0	33.4
Goodwill	280.7	207.0
Other intangible assets, net	268.7	212.9
Other noncurrent assets, net	111.0	100.0
Total assets	$3,332.0	$2,688.1
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$528.9	$355.8
Accrued interest payable	42.4	22.5
Accrued salaries, wages and benefits	23.4	14.0
Other taxes payable	22.9	16.7
Other current liabilities	41.5	36.2
Current portion of long-term debt	0.6	0.4
Derivative liabilities	0.6	54.8
Total current liabilities	660.3	500.4
Deferred income taxes	31.4	1.7
Pension and postretirement benefit obligations	10.5	11.7
Other long-term liabilities	1.0	1.1
Long-term debt, less current portion	1,683.1	1,110.4
Total liabilities	2,386.3	1,625.3
Commitments and contingencies		
Partners' capital:		
Limited partners' interest (69,452,233 and 69,317,278 common units issued and outstanding as of September 30, 2014 and December 31, 2013, respectively)	879.1	1,079.6
General partner's interest	32.8	36.6
Accumulated other comprehensive income (loss)	33.8	(53.4)

Total partners’ capital	945.7	1,062.8
Total liabilities and partners’ capital	$3,332.0	$2,688.1

See accompanying notes to unaudited condensed consolidated financial statements.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(In millions, except per unit and unit data)			
Sales	$1,675.8	$1,505.5	$4,451.7	$4,178.3
Cost of sales	1,493.2	1,443.4	4,045.3	3,880.8
Gross profit	182.6	62.1	406.4	297.5
Operating costs and expenses:				
Selling	43.6	13.9	103.3	46.7
General and administrative	26.5	15.8	73.3	59.9
Transportation	42.2	34.9	123.9	104.1
Taxes other than income taxes	4.2	3.7	9.9	9.7
Other	4.7	12.8	9.6	14.4
Operating income (loss)	61.4	(19.0)	86.4	62.7
Other income (expense):				
Interest expense	(28.4)	(24.2)	(83.3)	(73.7)
Debt extinguishment costs	(0.3)	—	(89.9)	—
Realized gain on derivative instruments	5.1	4.2	17.7	5.4
Unrealized gain (loss) on derivative instruments	(25.6)	2.4	22.6	22.9
Other	(0.7)	1.9	(1.8)	2.2
Total other expense	(49.9)	(15.7)	(134.7)	(43.2)
Net income (loss) before income taxes	11.5	(34.7)	(48.3)	19.5
Income tax expense	2.1	0.1	0.4	0.5
Net income (loss)	$9.4	$(34.8)	$(48.7)	$19.0
Allocation of net income (loss):				
Net income (loss)	$9.4	$(34.8)	$(48.7)	$19.0
Less:				
General partner’s interest in net income (loss)	0.2	(0.7)	(1.0)	0.4
General partner’s incentive distribution rights	3.8	3.8	11.5	10.9
Non-vested share based payments	—	—	—	0.2
Net income (loss) available to limited partners	$5.4	$(37.9)	$(59.2)	$7.5
Weighted average limited partner units outstanding:				
Basic	69,684,621	69,626,650	69,637,991	67,367,326
Diluted	69,850,685	69,626,650	69,637,991	67,553,709
Limited partners’ interest basic and diluted net income (loss) per unit	$0.08	$(0.54)	$(0.85)	$0.11
Cash distributions declared per limited partner unit	$0.685	$0.685	$2.055	$2.015

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 September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(In millions)			
Net income (loss)	$9.4	$(34.8)	$(48.7)	$19.0
Other comprehensive income:				
Cash flow hedges:				
Cash flow hedge (gain) loss reclassified to net income (loss)	(6.5)	(5.6)	(3.7)	4.4
Change in fair value of cash flow hedges	40.4	14.1	90.9	41.3
Defined benefit pension and retiree health benefit plans	(0.1)	0.1	0.1	1.0
Foreign currency translation adjustment	(0.4)	—	(0.1)	—
Total other comprehensive income	33.4	8.6	87.2	46.7
Comprehensive income (loss) attributable to partners’ capital	$42.8	$(26.2)	$38.5	$65.7

See accompanying notes to unaudited condensed consolidated financial statements.

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

	Accumulated Other Comprehensive Income (Loss)	Partners' Capital		
		General Partner	Limited Partners	Total
	(In millions)			
Balance at December 31, 2013	$(53.4)	$36.6	$1,079.6	$1,062.8
Other comprehensive income	87.2	—	—	87.2
Net income (loss)	—	10.5	(59.2)	(48.7)
Common units repurchased for phantom unit grants	—	—	(2.2)	(2.2)
Amortization of vested phantom units	—		2.2	2.2
Cash settlement of unit based compensation	—	—	(0.9)	(0.9)
Issuances of phantom units, net of taxes withheld	—	—	(1.2)	(1.2)
Proceeds from public offerings of common units, net	—	—	3.7	3.7
Contributions from Calumet GP, LLC	—	0.1	—	0.1
Distributions to partners	—	(14.4)	(142.9)	(157.3)
Balance at September 30, 2014	$33.8	$32.8	$879.1	$945.7

See accompanying notes to unaudited condensed consolidated financial statements.

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

	Nine Months Ended September 30,	
	2014	2013
	(In millions)	
Operating activities		
Net income (loss)	$(48.7)	$19.0
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	101.0	88.2
Amortization of turnaround costs	18.3	10.9
Non-cash interest expense	5.0	5.2
Non-cash debt extinguishment costs	19.0	—
Provision for doubtful accounts	0.8	0.6
Unrealized gain on derivative instruments	(22.6)	(22.9)
Non-cash equity based compensation	5.9	3.4
Other non-cash activities	4.4	14.5
Changes in assets and liabilities:		
Accounts receivable	(112.2)	(75.8)
Inventories	(9.1)	10.9
Prepaid expenses and other current assets	(1.6)	(0.3)
Derivative activity	0.2	3.0
Turnaround costs	(22.6)	(62.9)
Deposits	(1.8)	5.2
Other assets	—	0.1
Accounts payable	108.6	121.7
Accrued interest payable	19.9	5.3
Accrued salaries, wages and benefits	(13.4)	(5.8)
Accrued income taxes payable	—	(27.6)
Other taxes payable	4.2	8.4
Other liabilities	4.3	11.6
Pension and postretirement benefit obligations	(1.1)	(2.4)
Net cash provided by operating activities	58.5	110.3
Investing activities		
Additions to property, plant and equipment	(194.2)	(114.1)
Cash paid for acquisitions, net of cash acquired	(263.6)	(124.1)
Investment in unconsolidated affiliates	(60.9)	(17.8)
Proceeds from sale of property, plant and equipment	0.1	—
Net cash used in investing activities	(518.6)	(256.0)
Financing activities		
Proceeds from borrowings — revolving credit facility	1,133.2	731.9
Repayments of borrowings — revolving credit facility	(1,009.0)	(731.9)
Repayments of borrowings — senior notes	(500.0)	—
Payments on capital lease obligations	(0.7)	(0.9)
Proceeds from other financing obligations	—	3.5
Proceeds from senior notes offering	900.0	—
Debt issuance costs	(19.9)	—
Proceeds from public offerings of common units, net	3.7	392.5
Contribution from Calumet GP, LLC	0.1	8.4

Common units repurchased for phantom unit grants	(2.2)	(7.1)
Cash settlement of unit based compensation	(0.9)	—
Distributions to partners	(157.6)	(149.0)
Net cash provided by financing activities	346.7	247.4
Net increase (decrease) in cash and cash equivalents	(113.4)	101.7
Cash and cash equivalents at beginning of period	121.1	32.2
Cash and cash equivalents at end of period	$7.7	$133.9
Supplemental disclosure of non-cash financing and investing activities		
Non-cash property, plant and equipment additions	$39.5	$—
Non-cash capital lease	$39.4	$—

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 under the ticker symbol "CLMT." The general partner of the Company is Calumet GP, LLC, a Delaware limited liability company. As of September 30, 2014, the Company had 69,452,233 limited partner common units and 1,417,392 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, waxes, drilling fluids and fuel and fuel related products including gasoline, diesel, jet fuel, asphalt and heavy fuel oils. The Company is also engaged in the resale of purchased crude oil to third party customers. The Company is based in Indianapolis, Indiana and has thirteen manufacturing facilities primarily located in northwest Louisiana, northwest Wisconsin, northern Montana, western Pennsylvania, Texas, New Jersey and Oklahoma. The Company owns and leases additional facilities, primarily related to production and distribution of specialty and fuel products, throughout the United States ("U.S.").

The unaudited condensed consolidated financial statements of the Company as of September 30, 2014 and for the three and nine months ended September 30, 2014 and 2013 included herein have been prepared, without audit, pursuant to the rules and regulations of the Securities and Exchange Commission ("SEC"). Certain information and disclosures normally included in the consolidated financial statements prepared in accordance with generally accepted accounting principles ("GAAP") in the U.S. have been condensed or omitted pursuant to such rules and regulations, although the Company believes that the following disclosures are adequate to make the information presented not misleading. These unaudited condensed consolidated financial statements reflect all adjustments that, in the opinion of management, are necessary to present fairly the results of operations for the interim periods presented. All adjustments are of a normal nature, unless otherwise disclosed. The results of operations for the three and nine months ended September 30, 2014 are not necessarily indicative of the results that may be expected for the year ending December 31, 2014. These unaudited condensed consolidated financial statements should be read in conjunction with the Company's 2013 Annual Report.

2. Summary of Significant Accounting Policies

Revenue Recognition

The Company recognizes revenue on orders received from its customers when there is persuasive evidence of an arrangement with the customer that is supportive of revenue recognition, the customer has made a fixed commitment to purchase the product for a fixed or determinable sales price, collection is reasonably assured under the Company's normal billing and credit terms, all of the Company's obligations related to the product have been fulfilled and ownership and all risks of loss have been transferred to the buyer, which is primarily upon shipment to the customer or, in certain cases, upon receipt by the customer in accordance with contractual terms. The Company recognizes revenue on certain drilling fluids, completion fluids and production chemicals when consumed at the customer site during the drilling process.

Income Taxes

The Company, as a partnership, is generally not liable for federal and state income taxes on the earnings of Calumet Specialty Products Partners, L.P. and its wholly-owned subsidiaries. However, the Company conducts certain activities through wholly-owned subsidiaries that are corporations, including Anchor Drilling Fluids USA, Inc. ("Anchor"), which are subject to federal, state and local income taxes. Additionally, the Company is subject to franchise taxes in certain states. Income taxes on the earnings of the Company, with the exception of the above mentioned taxes, are the responsibility of its partners, with earnings of the Company included in partners' earnings.

In the event that the Company’s taxable income does not meet certain qualification requirements, the Company would be taxed as a corporation. Interest and penalties related to income taxes, if any, would be recorded in income tax expense. Generally, tax returns remain subject to examination by taxing authorities for three years. The Company had no unrecognized tax benefits as of September 30, 2014 and December 31, 2013.

The Company accounts for income taxes under the asset and liability method. Under this method, deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates in effect for the year in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rate is recognized in earnings in the period that includes the enactment date. Valuation allowances are established when necessary to reduce deferred tax assets to the amounts more likely than not to be realized.

The determination of the provision for income taxes requires significant judgment, use of estimates, and the interpretation and application of complex tax laws. Significant judgment is required in assessing the timing and amounts of deductible and taxable items and the probability of sustaining uncertain tax positions. The benefits of uncertain tax positions are recorded in the Company's financial statements only after determining a more-likely-than-not probability that the uncertain tax positions will withstand challenge, if any, from taxing authorities. When facts and circumstances change, the Company reassesses these probabilities and records any changes through the provision for income taxes.

Foreign Currency Translation and Transactions

Certain of the Company's subsidiaries use a local currency as their functional currency. Assets and liabilities of subsidiaries with a local currency as their functional currency are translated at period-end rates of exchange, and revenues and expenses are translated at average exchange rates prevailing for each month. The resulting translation adjustments are made directly to a separate component of other comprehensive income (loss), which is reflected in partners' capital in the Company's condensed consolidated balance sheets.

Certain of the Company's subsidiaries also enter into transactions and have monetary assets and liabilities that are denominated in a currency other than such entity's respective functional currency. Gains and losses from the revaluation of foreign currency transactions and monetary assets and liabilities are included in other expense in the unaudited condensed consolidated statements of operations.

New Accounting Pronouncements

In February 2013, the Financial Accounting Standards Board ("FASB") issued ASU No. 2013-04, Liabilities (Topic 405) — Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation Is Fixed at the Reporting Date ("ASU 2013-04"). ASU 2013-04 provides guidance for the recognition, measurement and disclosure of obligations resulting from joint and several liability arrangements from which the total amount of the obligation within the scope of this guidance is fixed at the reporting date. ASU 2013-04 is effective for fiscal periods (including interim periods) beginning after December 15, 2013 and should be applied retrospectively. The adoption of ASU 2013-04 did not have an impact on the Company's unaudited condensed consolidated financial statements.

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606) ("ASU 2014-09"), which supersedes the revenue recognition requirements in 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 will be effective beginning in fiscal year 2017 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 consolidated condensed statements of operations, balance sheets and cash flows.

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 condensed 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 annual periods ending after December 15, 2016, and for annual periods and interim periods thereafter. 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.

3. Income Taxes

The Company conducts certain activities through wholly-owned subsidiaries that are corporations which are subject to federal, state and local income taxes. The components of federal and state income tax expense are summarized as follows (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Current expense:				
Federal	$0.1	$—	$0.2	$—
State	0.1	0.1	0.2	0.5
Total	$0.2	$0.1	$0.4	$0.5
Deferred expense (benefit):				
Federal	$1.4	$—	$(0.4)	$—
State	0.5	—	0.4	—
Total	$1.9	$—	$—	$—
Total income tax expense	$2.1	$0.1	$0.4	$0.5

A reconciliation of effective tax rate to the U.S. statutory rate attributable to operations for the three and nine months ended September 30, 2014 and 2013 is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Federal income tax rate	35.0 %	35.0 %	35.0 %	35.0 %
Partnership earnings not subject to tax	(25.8)%	(35.0)%	(33.8)%	(35.0)%
State income taxes, net of federal income tax effect	5.0 %	(0.5)%	(1.2)%	2.7 %
Other items, net	4.1 %	0.2 %	(0.8)%	(0.1)%
Effective tax rate	18.3 %	(0.3)%	(0.8)%	2.6 %

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Deferred Taxes

Deferred taxes result from the temporary differences between financial reporting carrying amounts and the tax basis of existing assets and liabilities. The table below summarizes the principal components of the deferred tax assets (liabilities) as follows (in millions):

	September 30, 2014	December 31, 2013
Deferred income tax assets:		
Accruals and reserves	$0.1	$—
Inventory	0.8	—
Equity method investments	0.1	—
Net operating loss carryforwards	3.2	—
Total deferred income tax assets	$4.2	$—
Deferred income tax liabilities:		
Intangible assets	$(23.3)	$—
Property, plant and equipment	(11.4)	(1.7)
Total deferred income tax liabilities	$(34.7)	$(1.7)
Net deferred income tax liability	$(30.5)	$(1.7)

As a result of the Company's analysis, management has determined that the Company does not have any uncertain tax positions. As of September 30, 2014, the Company had tax loss carryforwards of approximately $12.6 million, which are expected to be utilized prior to expiration in 2034. As of December 31, 2013, the Company had no deferred tax assets arising from net operating loss carryforwards.

4. 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 and subject to certain purchase price adjustments ("SOS Acquisition"). SOS is a full-service drilling fluids and solids control company with operations in the Eagle Ford, Marcellus and Utica shales. 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 oil field 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, an independent provider and marketer of drilling fluids, completion fluids and production chemicals to the oil and gas industry ("Anchor Acquisition"). Total consideration was approximately $223.6 million, net of cash acquired and subject to certain other adjustments including tax adjustments. In connection with the Anchor Acquisition, the Company is required to pay 50% by which the amount of taxes paid in a post-closing tax period 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) to the sellers. 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 oil field services market, expands its geographic reach and increases its asset diversity.

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 acquisition increases its position in the specialty lubricants market.

On December 10, 2013, the Company completed the acquisition of 100% of the membership interests of Bel-Ray Company, LLC ("Bel-Ray"), a manufacturer and global marketer of high-performance lubricants and greases, for aggregate consideration of approximately $53.6 million, net of cash acquired and excluding debt assumed ("Bel-Ray Acquisition"). Bel-Ray distributes, both domestically and internationally, a wide array of high-end specialty synthetic lubricants and greases which are used in the aerospace, automotive, energy, food, marine, military, mining, motorcycle, powersports, steel and textiles industries. The Bel-Ray Acquisition was financed by using a portion of the net proceeds of $337.4 million from the Company's

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November 2013 private placement of 7.625% senior notes due January 15, 2022. The Company believes the Bel-Ray Acquisition increases its position in the specialty lubricants market, expands its geographic reach and increases its asset diversity. At closing, the Company repaid the $11.9 million of debt assumed in connection with the Bel-Ray Acquisition.

On August 9, 2013, the Company completed the acquisition of seven crude oil loading facilities and related assets in North Dakota and Montana from Murphy Oil USA, Inc. ("Murphy") for aggregate consideration of approximately $6.2 million ("Crude Oil Logistics Acquisition"). The Crude Oil Logistics Acquisition was funded with cash on hand. As part of this acquisition, the Company assumed pipeline space on the Enbridge Pipeline System ("Enbridge Pipeline") previously held by Murphy. The Company has the ability to transport crude oil directly from the point of lease, into the Company's acquired crude oil loading facilities and then onto the Enbridge Pipeline where it can be routed to the Company's refineries and/or third party customers. As part of this transaction, the Company and Murphy jointly consented to terminate an existing crude oil purchase agreement wherein Murphy supplied the Company's Superior refinery with up to 10,000 barrels per day of crude oil. The Company believes this acquisition expands its growing portfolio of crude oil logistics assets, while positioning the Company to purchase increased volumes of price-advantaged feedstock directly from the producers that operate in the major shale oil plays encompassing certain of the Company's refineries.

On January 2, 2013, the Company completed the acquisition of NuStar Energy L.P.'s ("NuStar") San Antonio, Texas refinery, together with related assets and the assumption of certain liabilities and obligations ("San Antonio Acquisition"). Total consideration for the San Antonio Acquisition was approximately $117.9 million, net of cash acquired. The refinery has total crude oil throughput capacity of 17,500 bpd and primarily produces diesel, jet fuel, gasoline, other fuel products and specialty solvents. The San Antonio Acquisition was funded with borrowings under the Company's revolving credit facility with the balance through cash on hand. The Company believes the San Antonio Acquisition further diversifies the Company's crude oil feedstock slate, operating asset base and geographic presence.

Purchase Price Allocation

The Anchor and SOS Acquisition purchase price allocations have not yet been finalized due to the timing of the closing of the acquisitions. The final determination of fair value for assets and liabilities will be completed as soon as the information necessary to complete the analyses are obtained. The assets and results of the operations from such assets acquired as a result of the San Antonio and Crude Oil Logistics Acquisitions have been included in the fuel products segments since their dates of acquisition, January 2, 2013 and August 9, 2013, respectively. The assets and results of operations from such assets acquired as a result of the Bel-Ray, United Petroleum, Anchor and SOS Acquisitions have been included in the specialty products segment since their dates of acquisition, December 10, 2013, February 28, 2014, March 31, 2014 and August 1, 2014, respectively.

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The allocations of the aggregate purchase prices to assets acquired and liabilities assumed for acquisitions are as follows (in millions):

	2014 Acquisitions			2013 Acquisitions		
	SOS	Anchor	United Petroleum	Bel-Ray	Crude Oil Logistics	San Antonio
Accounts receivable	$11.5	$75.4	$—	$4.3	$—	$—
Inventories	2.6	61.2	0.2	11.1	—	17.0
Prepaid expenses and other current assets	0.1	0.4	—	0.6	0.1	—
Deposits	—	0.6	—	—	—	—
Deferred tax asset	—	0.9	—	—	—	—
Property, plant and equipment, net	15.1	35.9	—	6.5	0.9	100.7
Investment in unconsolidated affiliates	—	1.9	—	—	—	—
Goodwill	1.2	67.5	5.0	9.1	5.2	5.7
Other intangible assets, net	5.7	74.0	5.2	41.4	—	—
Other noncurrent assets, net	—	—	—	0.3	—	—
Accounts payable	(6.2)	(44.2)	—	(3.9)	—	—
Accrued salaries, wages and benefits	—	(18.2)	—	(1.3)	—	(0.1)
Other taxes payable	(0.2)	(1.8)	—	(1.7)	—	—
Other current liabilities	(0.2)	(0.4)	—	(0.8)	—	(5.4)
Current portion of long-term debt	—	—	—	(11.9)	—	—
Deferred income tax liability	—	(29.6)	—	—	—	—
Other long-term liabilities	—	—	—	(0.1)	—	—
Total purchase price, net of cash acquired	$29.6	$223.6	$10.4	$53.6	$6.2	$117.9

Intangible Assets

The components of intangible assets listed in the table above, based upon preliminary third party appraisals, were as follows (in millions):

	SOS August 1, 2014		Anchor March 31, 2014		United Petroleum February 28, 2014		Bel-Ray December 10, 2013	
	Amount	Life (Years)	Amount	Life (Years)	Amount	Life (Years)	Amount	Life (Years)
Customer relationships	$3.8	15	$52.7	20	$3.8	20	$28.6	30
Tradenames	1.4	20	18.4	21	1.4	20	4.2	18
Trade secrets	—	—	—	—	—	—	8.5	18
Non-competition agreements	0.5	3	2.9	2	—	—	0.1	6
Totals	$5.7		$74.0		$5.2		$41.4	
Weighted average amortization period		15		20		20		26

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Goodwill

The Company recorded the following goodwill (in millions):

	Amount	Business Segment
SOS Acquisition [1]	$1.2	Specialty Products
Anchor Acquisition [1] [3]	$67.5	Specialty Products
United Petroleum Acquisition [1]	$5.0	Specialty Products
Bel-Ray Acquisition [1]	$9.1	Specialty Products
Crude Oil Logistics Acquisition [2]	$5.2	Fuel Products
San Antonio Acquisition [1]	$5.7	Fuel Products

(1) Goodwill recognized relates primarily to enhancing the Company’s strategic platform for expansion in the respective business segment noted above.

(2) Goodwill recognized relates primarily to enhancing the Company’s crude oil gathering operations to support the Superior refinery and sales to third party customers.

(3) Approximately $9.7 million of goodwill associated with the Anchor Acquisition is tax deductible due to Anchor’s tax status as a corporation.

Acquisition Expenses

In connection with the respective acquisitions, the Company incurred the following expenses, which are reflected in general and administrative expenses in the unaudited condensed consolidated statements of operations for the three and nine months ended September 30, 2014 and 2013 (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
SOS Acquisition	$0.1	$—	$0.1	$—
Anchor Acquisition	$0.1	$—	$0.6	$—
United Petroleum Acquisition	$—	$—	$0.1	$—
Bel-Ray Acquisition	$—	$—	$0.3	$—
Crude Oil Logistics Acquisition	$—	$0.2	$—	$0.2
San Antonio Acquisition	$—	$—	$—	$0.5

Results of Sales and Earnings

The following financial information reflects sales and operating income of the United Petroleum, Anchor and SOS Acquisitions that is included in the unaudited condensed consolidated statements of operations for the three and nine months ended September 30, 2014 (in millions):

	Three Months Ended September 30,	Nine Months Ended September 30,
	2014	
Sales	$135.6	$251.2
Operating income	$14.1	$19.7

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, 2013 (in millions, except for per unit data):

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	Three Months Ended September 30,	Nine Months Ended September 30,	
	2013	2014	2013
Sales	$1,585.9	$4,534.2	$4,408.3
Net income (loss)	$(30.3)	$(57.9)	$27.2
Limited partners' interest net income (loss) per unit — basic and diluted	$(0.48)	$(0.98)	$0.23

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.

5. 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 $33.8 million and $32.2 million higher as of September 30, 2014 and December 31, 2013, respectively.

Inventories consist of the following (in millions):

	September 30, 2014	December 31, 2013
Raw materials	$128.8	$122.7
Work in process	97.4	102.6
Finished goods	414.3	342.1
	$640.5	$567.4

Under the LIFO method, the most recently incurred costs are charged to cost of sales and inventories are valued at the earliest acquisition costs.

6. 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 $182.5 million from MDU and a total of $182.5 million from the Company comprised of $107.5 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 majority of the direct funding by the Company is expected to occur in 2014. The joint venture will allocate 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 will provide 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.

The Company accounts for its ownership in the Dakota Prairie joint venture under the equity method of accounting. As of September 30, 2014 and December 31, 2013, the Company had an investment of $76.3 million and $33.4

million, respectively, in Dakota Prairie primarily related to the development of the refinery. Equity in earnings of Dakota Prairie are immaterial for 2014.

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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 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. The Company intends to invest $25.0 million 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 September 30, 2014, the Company had an investment of $16.0 million in Juniper primarily related to the development of the plant.

7. Goodwill and Other Intangible Assets

Changes in goodwill balances are as follows (in millions):

	September 30, 2014			December 31, 2013		
	Specialty Products	Fuel Products	Total	Specialty Products	Fuel Products	Total
Beginning balance:	$168.5	$38.5	$207.0	$159.4	$27.6	$187.0
Acquisitions	73.7	—	73.7	9.1	10.9	20.0
Accumulated impairment losses	—	—	—	—	—	—
Ending balance:	$242.2	$38.5	$280.7	$168.5	$38.5	$207.0

Other intangible assets consist of the following (in millions):

	Weighted Average Life(Years)	September 30, 2014 Gross Amount	Accumulated Amortization	December 31, 2013 Gross Amount	Accumulated Amortization
Customer relationships	21	$243.2	$(60.6)	$182.9	$(40.3)
Supplier agreements	4	21.5	(21.5)	21.5	(21.5)
Tradenames	Indefinite	14.8	—	14.8	—
Tradenames	18	31.8	(3.9)	10.6	(1.6)
Trade secrets	13	52.7	(14.9)	52.7	(9.6)
Patents	12	1.6	(1.3)	1.6	(1.2)
Non-competition agreements	4	9.3	(6.8)	5.9	(5.8)
Distributor agreements	3	2.0	(2.0)	2.0	(2.0)
Royalty agreements	19	4.5	(1.7)	4.5	(1.6)
	18	$381.4	$(112.7)	$296.5	$(83.6)

Supplier agreements, tradenames (other than indefinite lived), trade secrets, patents, non-competition agreements, distributor agreements and royalty agreements are being amortized to properly match expense with the discounted estimated future cash flows over the terms of the related agreements or the period expected to be benefited. Agreements with terms allowing for the potential extension of such agreements are being amortized based on the initial term only. Customer relationships are being amortized using discounted estimated future cash flows based upon assumed rates of annual customer attrition.

For the three months ended September 30, 2014 and 2013, the Company recorded amortization expense of intangible assets of $10.8 million and $6.4 million, respectively. For the nine months ended September 30, 2014 and 2013, the Company recorded amortization expense of intangible assets of $29.1 million and $19.1 million, respectively.

As of September 30, 2014, the Company estimates that amortization of intangible assets for the next five years will be as follows (in millions):

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Year	Amortization Amount
2014	$11.0
2015	$41.1
2016	$34.9
2017	$30.0
2018	$25.3

8. 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 to increase over time. For example, on September 12, 2012, the EPA published final amendments to the New Source Performance Standards ("NSPS") for petroleum refineries, including standards for emissions of nitrogen oxides from process heaters and work practice standards and monitoring requirements for flares.

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 (see Note 4), the Company agreed to indemnify NuStar for an unlimited term and without consideration of a monetary 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 pre-dates 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. Periodic reporting is the primary current obligation under the Montana Consent Decree. On September 27, 2012, Montana Refining Company, Inc. received a final Corrective Action Order on Consent, replacing the refinery's previous 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 HollyFrontier 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. Holly has provided the Company a notice challenging the Company's position that Holly is obligated to indemnify the Company's remediation expenses which total approximately $14.7 million as of September 30, 2014, of which $12.3 million was capitalized and $2.4 million was expensed. The Company continues to believe that Holly is responsible to indemnify the Company for the remediation expenses disputed by Holly, and the Company has invoked the dispute resolution procedure under 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 expansion of that refinery; however, the Company believes at this time that the costs it may incur will not be material to its financial position or results of operations.

Superior Refinery

In connection with the Superior acquisition, 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 currently estimates costs of up to $1.0 million to make known equipment upgrades and conduct other discrete tasks in compliance with the Superior Consent Decree. Failure to perform required tasks under the Superior Consent Decree could result in the imposition of stipulated penalties, which could be material. Due to certain occurrences of non-compliance by the Company, the Company expects that it may have liability for some stipulated penalties. However, the Company has not received formal notice of an obligation to pay stipulated penalties, and the Company does not believe the amount of the stipulated penalties for which it may now be liable are material. In addition, the Company may have to pursue 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 September 30, 2014 and 2013, the Company incurred approximately $0.2 million and $0.5 million of costs, respectively, related to installing process equipment pursuant to the EPA fuel content regulations. For the nine months ended September 30, 2014 and 2013, the Company incurred approximately $0.7 million and $0.7 million of costs, respectively, related to installing process equipment 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 attended an informal conference with the EPA held September 12, 2012. 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 31, 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 September 30, 2014 and 2013, the Company incurred approximately $0.1 million and $0.3 million, respectively, of such expenditures. During the nine months ended September 30, 2014 and 2013, the Company incurred approximately $0.3 million and $4.8 million, respectively, of such expenditures and estimates additional expenditures of approximately $6.0 million to $8.0 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 required 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 September 30, 2014, the trust fund contained approximately $0.7 million. In addition, there is 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.

Other

Current and former owners of a property in Bossier Parish, Louisiana, filed a lawsuit in March 2006 against the Company and other defendants, including Chevron USA, Inc. (“Chevron”), Legacy Resources Co., L.P. (“Legacy”) and Exxon Mobil Corporation (“Exxon Mobil”), alleging damage from salt water and other environmental contamination on the property arising from historical oil field production on the property. Oil field exploration and production on the property began in the 1920’s by predecessors of Exxon Mobil. The Company received an assignment of certain mineral leases for portions of the property in 1993 from an affiliate of Texaco, prior to Texaco’s merger with Chevron. The Company then assigned those mineral leases to Legacy. The mineral lease assignments include indemnity provisions obligating the assignees to provide certain indemnities for an unlimited term and without consideration of a monetary cap for the benefit of the assignors. The Company, Chevron, Legacy and the plaintiffs have agreed upon a settlement of the litigation, which settlement is subject to approval by the Louisiana Department of Natural Resources and the court in which the litigation was proceeding. The Company’s obligations under the settlement agreement will be covered under the indemnification.

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 September 30, 2014 and 2013, the Company incurred approximately $0.4 million and $0.8 million, respectively, of related capital expenditures to address OSHA compliance issues identified in these studies. During the nine months ended September 30, 2014 and 2013, the Company incurred approximately $0.9 million and $2.8 million, respectively, of related capital expenditures and expects to incur up to $1.0 million during 2014 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 has 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 Missouri facility collective bargaining agreement was ratified on February 21, 2014 and will expire on April 30, 2015. The Princeton refinery collective bargaining agreement was ratified on October 29, 2014 and will expire on October 31, 2017.

Standby Letters of Credit

The Company has agreements with various financial institutions for standby letters of credit which have been issued to vendors. As of September 30, 2014 and December 31, 2013, the Company had outstanding standby letters of credit of $149.9 million and $95.2 million, respectively, under its senior secured revolving credit facility, which was amended and restated on July 14, 2014 (the "revolving credit facility"). Refer to Note 9 for additional information regarding the Company's revolving credit facility. At December 31, 2013, 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 $680.0 million, which is the greater of (i) $400.0 million and (ii) 80% of revolver commitments in effect ($850.0 million at December 31, 2013). At September 30, 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 ($1,000.0 million at September 30, 2014) with the consent of the Agent (as defined in the revolving credit facility agreement).

As of September 30, 2014 and December 31, 2013, the Company had availability to issue letters of credit of $450.1 million and $472.4 million, respectively, under its revolving credit facility.

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9. Long-Term Debt

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

	September 30, 2014	December 31, 2013
Borrowings under amended and restated senior secured revolving credit agreement with third-party lenders, interest payments monthly, borrowings due July 2019, weighted average interest rate of 3.5% at September 30, 2014	$124.2	$—
Borrowings under 2019 Notes, interest at a fixed rate of 9.375%, interest payments semiannually, borrowings due May 2019	—	500.0
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 nine months ended September 30, 2014	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 nine months ended September 30, 2014	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 nine months ended September 30, 2014 [1]	349.4	350.0
Capital lease obligations, at various interest rates, interest and principal payments monthly through September 2034	43.8	4.8
Less unamortized discounts	(8.7)	(19.0)
Total long-term debt	1,683.7	1,110.8
Less current portion of long-term debt	0.6	0.4
	$1,683.1	$1,110.4

(1) The balance includes a fair value interest rate hedge adjustment, which decreased the debt balance by $0.6 million as of September 30, 2014 (refer to Note 10 for additional information on the interest rate swap designated as a fair value hedge).

Senior Notes

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 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 4 for additional information), the redemption of $500.0 million in aggregate principal amount outstanding of 2019 Notes (defined below) 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.

At any time prior to April 15, 2017, the Company may on any one or more occasions redeem up to 35% of the aggregate principal amount of the 2021 Notes with the net proceeds of a public or private equity offering at a redemption price of 106.5% of the principal amount, plus any accrued and unpaid interest to the date of redemption, provided that: (1) at least 65% of the aggregate principal amount of 2021 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, 2017, the Company may on any one or more occasions redeem all or a part of the 2021 Notes at the redemption prices (expressed as percentages of principal amount) set forth below, plus any accrued and unpaid interest to the applicable redemption date on such 2021 Notes, if redeemed during the twelve-month period beginning on April 15 of the years indicated below:

Year	Percentage
2017	103.250 %

2018	101.625	%
2019 and thereafter	100.000	%

Prior to April 15, 2017, the Company may on any one or more occasions redeem all or part of the 2021 Notes at a redemption price equal to the sum of: (1) the principal amount thereof, plus (2) a make-whole premium (as set forth in the indenture governing the 2021 Notes) at the redemption date, plus any accrued and unpaid interest to the applicable redemption date.

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 at a discounted price of 98.494 percent of par. The Company received net proceeds of $337.4 million, net of discount, initial purchasers’ fees and expenses, which the Company used to fund the purchase price of the Bel-Ray Acquisition, the redemption of $100.0 million in aggregate principal amount outstanding of 2019 Notes (defined below) and for general partnership purposes, including planned capital expenditures at the Company’s facilities.
9.625% Senior Notes (the “2020 Notes”)
On June 29, 2012, in connection with the Royal Purple Acquisition, the Company issued and sold $275.0 million in aggregate principal amount of 9.625% senior notes due August 1, 2020 at a discounted price of 98.25 percent of par. The Company received net proceeds of $262.5 million, net of discount, initial purchasers’ fees and expenses, which the Company used to fund a portion of the purchase price of the Royal Purple Acquisition.
9.375% Senior Notes (the “2019 Notes”)
On April 21, 2011, in connection with the restructuring of the majority of its outstanding long-term debt, the Company issued and sold $400.0 million in aggregate principal amount of 9.375% senior notes due May 1, 2019 (the “2019 Notes issued in April 2011”) at par. The Company received net proceeds of $389.0 million net of initial purchasers’ fees and expenses, which the Company used to repay in full borrowings outstanding under its prior term loan, as well as all accrued interest and fees, and for general partnership purposes. On September 19, 2011, in connection with the acquisition of the Superior refinery, the Company issued and sold $200.0 million in aggregate principal amount of 9.375% senior notes due May 1, 2019 (the “2019 Notes issued in September 2011”) at a discounted price of 93.0 percent of par. The Company received net proceeds of $180.3 million net of discount, initial purchasers’ fees and expenses, which the Company used to fund a portion of the purchase price of the Superior refinery. Because the terms of the 2019 Notes issued in September 2011 are substantially identical to the terms of the 2019 Notes issued in April 2011, in this Quarterly Report, the Company collectively refers to the 2019 Notes issued in April 2011 and the 2019 Notes issued in September 2011 as the “2019 Notes.”
On March 31, 2014, the Company redeemed approximately $326.0 million and $174.0 million in aggregate principal amount outstanding of the remaining 2019 Notes issued in April 2011 and 2019 Notes issued in September 2011, respectively, with the net proceeds from the issuance of the 2021 Notes at a redemption price of $570.9 million. In conjunction with the early redemption, the Company recognized a loss of $89.6 million recorded in debt extinguishment costs in the unaudited condensed consolidated statements of operations for the nine months ended September 30, 2014.
2020 Notes, 2021 Notes and 2022 Notes
In accordance with 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 and 2022 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 and 2022 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 Rule 4-08(e)(3) of Regulation S-X.
The 2020, 2021 and 2022 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 and 2022 Notes.

The indentures governing the 2020, 2021 and 2022 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 and 2022 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 and 2022 Notes, has

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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 September 30, 2014, the Company's Fixed Charge Coverage Ratio (as defined in the indentures governing the 2020, 2021 and 2022 Notes) was 2.4 to 1.0.

Second Amended and Restated Senior Secured Revolving Credit Facility

On July 14, 2014, the Company entered into a second amended and restated senior secured revolving credit facility, which increased the maximum availability of credit under the revolving credit facility from $850.0 million to $1,000.0 million, subject to borrowing base limitations, and includes a $500.0 million incremental uncommitted expansion feature. The revolving credit facility, which is the Company's primary source of liquidity for cash needs in excess of cash generated from operations, matures in July 2019 and bears interest at a rate equal to prime plus a basis points margin or LIBOR plus a basis points margin, at the Company's option. As of September 30, 2014, 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 as follows:

Quarterly Average Availability Percentage	Margin on Base Rate Revolving Loans	Margin on LIBOR Revolving Loans
≥ 66%	0.50%	1.50%
≥ 33% and < 66%	0.75%	1.75%
< 33%	1.00%	2.00%

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

The borrowing capacity at September 30, 2014 under the revolving credit facility was $831.5 million. As of September 30, 2014, the Company had $124.2 million in outstanding borrowings under the revolving credit facility and outstanding standby letters of credit of $149.9 million, leaving $557.4 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 September 30, 2014, the Company was in compliance with all covenants under the revolving credit facility.

Capital Leases

On July 7, 2014, the Company entered into a capital lease agreement with TexStar Midstream Logistics, L.P. ("TexStar") under which TexStar will construct, own and operate a 30,000 bpd crude oil pipeline system that will supply significant volumes of Eagle Ford crude oil to the Company's San Antonio refinery for a term of 20 years. The pipeline became fully operational on November 1, 2014. The total obligation and asset under the capital lease agreement as of September 30, 2014 was $39.4 million. The asset recorded under this capital lease obligation is included in property, plant and equipment. No depreciation was recorded during the three and nine months ended September 30, 2014.

As of September 30, 2014, the Company had estimated minimum commitments for the payment of total rentals under capital leases as follows (in millions):

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Year	Capital Leases
2014	$1.8
2015	7.0
2016	7.0
2017	7.0
2018	7.0
Thereafter	109.3
Total minimum lease payments	139.1
Less amount representing interest	95.3
Capital lease obligations	43.8
Less obligations due within one year	0.6
Long-term capital lease obligations	$43.2

Maturities of Long-Term Debt

As of September 30, 2014, principal payments on debt obligations and future minimum rentals on capital lease obligations are as follows (in millions):

Year	Maturity
2014	$0.1
2015	0.6
2016	0.7
2017	0.7
2018	0.8
Thereafter	1,690.1
Total	$1,693.0

10. 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) and natural gas. 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; 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. 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

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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 governance over commodity and derivative activities includes regular monitoring of the performance of the Company's risk management strategies and transaction limits regarding dollars and volume based authority, commodity positions, crack spread positions and other various risk management performance measures. The Company's risk management results are reviewed monthly by its risk management committee and summarized and reviewed quarterly with the Board of Directors of the Company's general partner.

The Company recognizes all derivative instruments at their fair values (see Note 11) 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 it 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 September 30, 2014 and December 31, 2013 (in millions):

	September 30, 2014			December 31, 2013		
	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	$7.5	$ (28.5)	$ (21.0)	$45.4	$ (45.4)	$ —
Gasoline swaps	23.6	—	23.6	1.0	(1.0)	—
Diesel swaps	39.3	(0.1)	39.2	3.5	(3.5)	—
Jet fuel swaps	6.0	—	6.0	0.1	(0.1)	—
Total derivative instruments designated as hedges	76.4	(28.6)	47.8	50.0	(50.0)	—
Derivative instruments not designated as hedges:						
Fuel products segment:						
Crude oil swaps	0.4	(2.0)	(1.6)	6.3	(6.3)	—
Crude oil basis swaps	2.8	—	2.8	1.0	(1.0)	—
Diesel swaps	8.7	(0.6)	8.1	0.7	(0.7)	—
Jet fuel swaps	—	—	—	0.9	(0.9)	—
Diesel crack spread collars	0.7	(0.7)	—	0.3	(0.3)	—
Specialty products segment:						
Natural gas swaps	0.3	(2.6)	(2.3)	0.4	(0.4)	—
Natural gas collars	0.5	(0.5)	—	—	—	—
Total derivative instruments not designated as hedges	13.4	(6.4)	7.0	9.6	(9.6)	—

Total derivative instruments	$ 89.8	$ (35.0)	$ 54.8	$ 59.6	$ (59.6)	$ —

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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 September 30, 2014 and December 31, 2013 (in millions):

	September 30, 2014			December 31, 2013		
	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	$(28.5)	$28.5	$—	$(13.0)	$45.4	$32.4
Gasoline swaps	—	—	—	(19.7)	1.0	(18.7)
Diesel swaps	(0.1)	0.1	—	(51.3)	3.5	(47.8)
Jet fuel swaps	—	—	—	(13.4)	0.1	(13.3)
Swaps not allocated to a specific segment:						
Interest rate swap	(0.6)	—	(0.6)	—	—	—
Total derivative instruments designated as hedges	(29.2)	28.6	(0.6)	(97.4)	50.0	(47.4)
Derivative instruments not designated as hedges:						
Fuel products segment:						
Crude oil swaps	(2.0)	2.0	—	(1.7)	6.3	4.6
Crude oil basis swaps	—	—	—	(0.6)	1.0	0.4
Gasoline swaps	—	—	—	(9.4)	—	(9.4)
Diesel swaps	(0.6)	0.6	—	(3.5)	0.7	(2.8)
Jet fuel swaps	—	—	—	—	0.9	0.9
Diesel crack spread collars	(0.7)	0.7	—	(0.2)	0.3	0.1
Specialty products segment:						
Natural gas swaps	(2.6)	2.6	—	(1.6)	0.4	(1.2)
Natural gas collars	(0.5)	0.5	—	—	—	—
Total derivative instruments not designated as hedges	(6.4)	6.4	—	(17.0)	9.6	(7.4)
Total derivative instruments	$(35.6)	$35.0	$(0.6)	$(114.4)	$59.6	$(54.8)

The Company is exposed to credit risk in the event of nonperformance by its counterparties on these derivative transactions. The Company does not expect nonperformance on any derivative instruments, however, no assurances can be provided. The Company's credit exposure related to these derivative instruments is represented by the fair value of contracts reported as derivative assets. As of September 30, 2014, the Company had eight counterparties in which derivatives held were net assets, totaling $54.8 million. As of December 31, 2013, the Company had no counterparties in which the derivatives held were net assets. To manage credit risk, the Company selects and periodically reviews counterparties based on credit ratings. The Company primarily executes its derivative instruments with large financial institutions that have ratings of at least 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

September 30, 2014 or December 31, 2013. 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 September 30, 2014 and December 31, 2013, 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.

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

The cash flow impact of the Company's derivative activities is classified primarily as a change in derivative activity in the operating activities section in the unaudited condensed consolidated statements of cash flows.

Derivative Instruments Designated as Cash Flow Hedges

The Company accounts for certain derivatives hedging purchases of crude oil and sales of gasoline, diesel and jet fuel swaps as cash flow hedges. The derivative instruments designated as cash flow hedges that are hedging sales and purchases are recorded to sales and cost of sales, respectively, in the unaudited condensed consolidated statements of operations upon recording the related hedged transaction in sales or cost of sales. The Company assesses, both at inception of the cash flow hedge and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items. Periodically, the Company may enter into crude oil and fuel product basis swaps to more effectively hedge its crude oil purchases, crude oil sales and fuel products sales. These derivatives can be combined with a swap contract in order to create a more effective cash flow hedge.

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

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

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

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 September 30, 2014 and 2013 related to its derivative instruments that were designated as cash flow hedges (in millions):

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Type of Derivative	Amount of Gain (Loss) Recognized in Accumulated Other Comprehensive Income (Loss) on Derivatives (Effective Portion)		Amount of Gain (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) into Net Income (Effective Portion)			Amount of Gain (Loss) Recognized in Net Income on Derivatives (Ineffective Portion)		
	Three Months Ended September 30,		Location of Gain (Loss)	Three Months Ended September 30,		Location of Gain (Loss)	Three Months Ended September 30,	
	2014	2013		2014	2013		2014	2013
Fuel products segment:								
Crude oil swaps	$(83.9)	$59.2	Cost of sales	$10.9	$11.1	Unrealized/ Realized	$(35.3)	$11.3
Gasoline swaps	37.0	(0.3)	Sales	(3.8)	(0.1)	Unrealized/ Realized	(4.4)	(0.6)
Diesel swaps	75.1	(33.1)	Sales	(1.1)	(4.4)	Unrealized/ Realized	13.4	(0.6)
Jet fuel swaps	12.2	(11.7)	Sales	(0.7)	(0.2)	Unrealized/ Realized	2.0	(0.5)
Specialty products segment:								
Crude oil swaps	—	—	Cost of sales	1.2	(0.8)	Unrealized/ Realized	—	—
Total	$40.4	$14.1		$6.5	$5.6		$(24.3)	$9.6

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 nine months ended September 30, 2014 and 2013 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 (Loss) on Derivatives (Effective Portion)		Amount of Gain (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) into Net Income (Effective Portion)			Amount of Gain (Loss) Recognized in Net Income (Loss) on Derivatives (Ineffective Portion)		
	Nine Months Ended September 30,		Location of Gain (Loss)	Nine Months Ended September 30,		Location of Gain (Loss)	Nine Months Ended September 30,	
	2014	2013		2014	2013		2014	2013
Fuel products segment:								
Crude oil swaps	$(12.7)	$32.5	Cost of sales	$34.0	$(2.5)	Unrealized/ Realized	$12.4	$(16.5)
Gasoline swaps	27.0	(0.7)	Sales	(15.3)	(0.2)	Unrealized/ Realized	(8.9)	(1.2)
Diesel swaps	61.7	8.5	Sales	(12.2)	(3.0)	Unrealized/ Realized	13.3	(3.9)
Jet fuel swaps	14.9	1.0	Sales	(2.8)	1.8	Unrealized/ Realized	1.6	6.0
Specialty products segment:								
Crude oil swaps	—	—	Cost of sales	—	(0.5)	Unrealized/ Realized	—	—
Total	$90.9	$41.3		$3.7	$(4.4)		$18.4	$(15.6)

The effective portion of the cash flow hedges classified in accumulated other comprehensive income (loss) was a gain of $35.8 million and a loss of $51.4 million as of September 30, 2014 and December 31, 2013, 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 September 30, 2014 will be reclassified to earnings by December 31, 2016 with balances being recognized as follows (in millions):

Year	Accumulated Other Comprehensive Income (Loss)
2014	$ 20.6
2015	13.2
2016	2.0
Total	$ 35.8

Based on fair values as of September 30, 2014, the Company expects to reclassify $32.4 million of net gains on derivative instruments from accumulated other comprehensive income (loss) 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.

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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 converts a portion of the Company’s fixed rate debt to a floating rate. This agreement involves the receipt of fixed rate amounts in exchange for floating rate interest payments over the life of the agreement without an exchange of the underlying principal amount. Also, in connection with the interest rate swap agreement, the Company entered into an option that permits the counterparty to cancel the interest rate swap for a specified premium. The Company designated this interest rate swap and option as a fair value hedge. As of September 30, 2014, the total notional amount of the Company’s receive-fixed/pay-variable interest rate swap was $200.0 million with a maturity date of January 15, 2022.

The Company recorded the following gains (losses) in its unaudited condensed consolidated statements of operations for the three and nine months ended September 30, 2014 and 2013 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 September 30, 2014	2013	Nine Months Ended September 30, 2014	2013	Hedged Item	Location of Gain (Loss) on Hedged Item	Amount of Gain Recognized in Net Income (Loss) Three Months Ended September 30, 2014	2013	Nine Months Ended September 30, 2014	2013
Swaps not allocated to a specific segment:											
Interest rate swap	Interest expense	$—	$—	$(0.6)	$—	2022 Notes	Interest income	$—	$—	$0.6	$—
Total		$—	$—	$(0.6)	$—			$—	$—	$0.6	$—

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 and gasoline swaps that do not qualify as cash flow hedges for accounting purposes as they are determined not to be highly effective in offsetting changes in the cash flows associated with crude oil purchases and gasoline and diesel sales at the Company’s Superior refinery.

Effective January 1, 2012, cash flow hedge accounting was discontinued prospectively for certain crude oil derivative instruments when it was determined that they were no longer highly effective in offsetting changes in the cash flows associated with crude oil purchases at the Company’s Superior refinery due to the volatility in crude oil pricing differentials between heavy crude oil and NYMEX WTI. Effective April 1, 2012, cash flow hedge accounting was discontinued prospectively for certain gasoline and diesel derivative instruments associated with gasoline and diesel sales at the Company’s Superior refinery. The discontinuance of cash flow hedge accounting on these existing derivative instruments has caused the Company to

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recognize the following gains and losses in the unaudited condensed consolidated statements of operations for the three and nine months ended September 30, 2013 (in millions):

	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2013
Realized gain on derivative instruments	$0.5	$1.5
Unrealized gain (loss) on derivative instruments	$(3.0)	$3.1

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 and nine months ended September 30, 2014 (in millions):

	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2014
Realized gain (loss) on derivative instruments	$1.0	$(2.3)
Unrealized gain on derivative instruments	$3.4	$2.1

The Company recorded the following gains (losses) in its unaudited condensed consolidated statements of operations for the three months ended September 30, 2014 and 2013 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 September 30,		Amount of Gain (Loss) Recognized in Unrealized Gain (Loss) on Derivative Instruments Three Months Ended September 30,	
	2014	2013	2014	2013
Fuel products segment:				
Crude oil swaps	$3.7	$2.0	$(21.0)	$2.7
Crude oil basis swaps	1.6	(0.2)	3.0	(7.2)
Gasoline swaps	(4.6)	—	8.4	(0.4)
Diesel swaps	2.6	0.9	13.3	(1.1)
Jet fuel swaps	—	0.7	—	0.5
Diesel crack spread collars	—	—	(0.5)	—
Gasoline crack spread collars	—	—	(0.2)	—
Specialty products segment:				
Crude oil swaps	—	0.1	—	(0.1)
Natural gas swaps	(0.1)	—	(2.4)	(0.9)
Total	$3.2	$3.5	$0.6	$(6.5)

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The Company recorded the following gains (losses) in its unaudited condensed consolidated statements of operations for the nine months ended September 30, 2014 and 2013 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 Nine Months Ended September 30,		Amount of Gain (Loss) Recognized in Unrealized Gain (Loss) on Derivative Instruments Nine Months Ended September 30,	
	2014	2013	2014	2013
Fuel products segment:				
Crude oil swaps	$18.1	$(6.8)	$(6.5)	$42.5
Crude oil basis swaps	2.8	7.3	2.5	(1.9)
Gasoline swaps	(15.8)	2.9	9.4	(0.4)
Diesel swaps	1.0	6.4	10.8	(4.5)
Jet fuel swaps	(0.5)	0.7	(0.9)	0.4
Diesel crack spread collars	1.0	—	(0.1)	—
Specialty products segment:				
Crude oil swaps	—	1.8	—	(1.6)
Natural gas swaps	1.2	—	(1.1)	(2.9)
Total	$7.8	$12.3	$14.1	$31.6

Derivative Positions - Specialty Products Segment

Natural Gas Swap Contracts

At September 30, 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
Fourth Quarter 2014	1,210,000	$4.19
Calendar Year 2015	4,930,000	4.23
Calendar Year 2016	4,340,000	4.32
Calendar Year 2017	1,830,000	4.28
Total	12,310,000	
Average price		$4.27

At December 31, 2013, 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 2014	750,000	$4.14
Second Quarter 2014	750,000	4.14
Third Quarter 2014	750,000	4.14
Fourth Quarter 2014	850,000	4.21
Calendar Year 2015	3,500,000	4.27
Calendar Year 2016	2,700,000	4.42
Calendar Year 2017	1,000,000	4.29
Total	10,300,000	
Average price		$4.28

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Natural Gas Collar Contracts

At September 30, 2014, the Company had the following natural gas collars 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)
Fourth Quarter 2014	160,000	$4.25	$3.79
Calendar Year 2015	920,000	4.25	3.80
Calendar Year 2016	600,000	4.25	3.89
Total	1,680,000		
Average price		$4.25	$3.83

Derivative Positions - Fuel Products Segment

Crude Oil Swap Contracts

At September 30, 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)
Fourth Quarter 2014	2,346,000	25,500	$92.75
Calendar Year 2015	6,830,000	18,712	90.12
Calendar Year 2016	2,196,000	6,000	85.65
Total	11,372,000		
Average price			$89.80

At September 30, 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)
Fourth Quarter 2014	184,000	2,000	$92.20
Calendar Year 2015	1,004,000	2,751	89.28
Total	1,188,000		
Average price			$89.74

At September 30, 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)
Fourth Quarter 2014	46,000	500	$96.90
Total	46,000		
Average price			$96.90

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At December 31, 2013, 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 2014	2,520,000	28,000	$92.06
Second Quarter 2014	2,411,500	26,500	91.97
Third Quarter 2014	2,530,000	27,500	91.23
Fourth Quarter 2014	2,024,000	22,000	90.61
Calendar Year 2015	5,556,500	15,223	89.08
Calendar Year 2016	1,830,000	5,000	84.73
Total	16,872,000		
Average price			$89.97

At December 31, 2013, 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 2014	810,000	9,000	$94.56
Second Quarter 2014	591,500	6,500	94.37
Third Quarter 2014	874,000	9,500	92.92
Fourth Quarter 2014	184,000	2,000	94.62
Calendar Year 2015	1,004,000	2,751	89.28
Total	3,463,500		
Average price			$92.59

At December 31, 2013, 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 2014	45,000	500	$96.90
Second Quarter 2014	45,500	500	96.90
Third Quarter 2014	46,000	500	96.90
Fourth Quarter 2014	46,000	500	96.90
Total	182,500		
Average price			$96.90

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 September 30, 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)
Fourth Quarter 2014	366,000	6,000	$(21.42)
Calendar Year 2015	180,000	493	(22.40)
Total	546,000		
Average differential			$(21.74)

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At December 31, 2013, 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 2014	118,000	1,311	$(28.50)
Third Quarter 2014	184,000	2,000	(21.75)
Fourth Quarter 2014	184,000	2,000	(21.50)
Total	486,000		
Average differential			$(23.29)

As of December 31, 2013, the Company had approximately 248,000 barrels of crude oil basis swaps related to future crude oil purchases and sales to mitigate the risk of future changes in pricing differentials between Brent and NYMEX WTI on the Company's reselling of crude oil. The net impact of these derivative instruments, none of which are designated as hedges, was a net loss of $0.6 million that was recorded to realized gain (loss) on derivative instruments in the unaudited condensed consolidated statements of operations for the nine months ended September 30, 2014.

Diesel Swap Contracts

At September 30, 2014, the Company had the following derivatives related to diesel sales in its fuel products segment, all of which are designated as cash flow hedges.

Diesel Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
Fourth Quarter 2014	1,104,000	12,000	$116.39
Calendar Year 2015	4,781,500	13,100	115.81
Calendar Year 2016	2,196,000	6,000	112.88
Total	8,081,500		
Average price			$115.10

At September 30, 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)
Fourth Quarter 2014	184,000	2,000	$120.38
Calendar Year 2015	1,004,000	2,751	117.15
Total	1,188,000		
Average price			$117.65

At September 30, 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)
Fourth Quarter 2014	46,000	500	$121.80
Total	46,000		
Average price			$121.80

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At December 31, 2013, the Company had the following derivatives related to diesel sales in its fuel products segment, all of which are designated as cash flow hedges.

Diesel Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
First Quarter 2014	1,125,000	12,500	$117.54
Second Quarter 2014	1,183,000	13,000	116.78
Third Quarter 2014	1,288,000	14,000	116.82
Fourth Quarter 2014	1,288,000	14,000	116.96
Calendar Year 2015	4,781,500	13,100	115.81
Calendar Year 2016	1,830,000	5,000	112.00
Total	11,495,500		
Average price			$115.72

At December 31, 2013, 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 2014	270,000	3,000	$121.72
Second Quarter 2014	182,000	2,000	123.22
Third Quarter 2014	230,000	2,500	121.74
Fourth Quarter 2014	184,000	2,000	123.02
Calendar Year 2015	1,004,000	2,751	117.15
Total	1,870,000		
Average price			$119.54

At December 31, 2013, 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 2014	45,000	500	$121.80
Second Quarter 2014	45,500	500	121.80
Third Quarter 2014	46,000	500	121.80
Fourth Quarter 2014	46,000	500	121.80
Total	182,500		
Average price			$121.80

Diesel Crack Spread Collars

At September 30, 2014, the Company had the following diesel crack spread collars related to diesel sales and crude oil purchases in its fuel products segment, none of which are designated as hedges.

Diesel Crack Spread Collars by Expiration Dates	Barrels Purchased and Sold	BPD	Average Bought Put ($/Bbl)	Average Sold Call ($/Bbl)
Fourth Quarter 2014 (1)	92,000	1,000	$26.00	$35.00
Total	92,000			
Average price			$26.00	$35.00

(1) During the third quarter 2014, the Company entered into a diesel crack spread collar, which is not designated as a hedge, which is the reverse position of the diesel crack spread collars expiring in the fourth quarter 2014 noted above.

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At December 31, 2013, the Company had the following diesel crack spread collars related to diesel sales and crude oil purchases in its fuel products segment, none of which are designated as hedges.

Diesel Crack Spread Collars by Expiration Dates	Barrels Purchased and Sold	BPD	Average Bought Put ($/Bbl)	Average Sold Call ($/Bbl)
First Quarter 2014	90,000	1,000	$26.00	$35.00
Second Quarter 2014	91,000	1,000	26.00	35.00
Third Quarter 2014	92,000	1,000	26.00	35.00
Fourth Quarter 2014	92,000	1,000	26.00	35.00
Total	365,000			
Average price			$26.00	$35.00

Jet Fuel Swap Contracts

At September 30, 2014, the Company had the following derivatives related to jet fuel sales in its fuel products segment, all of which are designated as cash flow hedges.

Jet Fuel Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
Fourth Quarter 2014	276,000	3,000	$115.65
Calendar Year 2015	957,500	2,623	114.25
Total	1,233,500		
Average price			$114.56

At December 31, 2013, the Company had the following derivatives related to jet fuel sales in its fuel products segment, all of which are designated as cash flow hedges.

Jet Fuel Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
First Quarter 2014	450,000	5,000	$117.50
Second Quarter 2014	273,000	3,000	116.68
Third Quarter 2014	276,000	3,000	116.18
Fourth Quarter 2014	276,000	3,000	115.65
Calendar Year 2015	775,000	2,123	114.05
Total	2,050,000		
Average price			$115.66

At December 31, 2013, 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 2014	90,000	1,000	$116.71
Total	90,000		
Average price			$116.71

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Gasoline Swap Contracts

At September 30, 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)
Fourth Quarter 2014	966,000	10,500	$108.07
Calendar Year 2015	1,091,000	2,989	112.83
Total	2,057,000		
Average price			$110.59

At December 31, 2013, 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 2014	945,000	10,500	$104.39
Second Quarter 2014	955,500	10,500	109.68
Third Quarter 2014	966,000	10,500	106.60
Fourth Quarter 2014	460,000	5,000	104.85
Total	3,326,500		
Average price			$106.61

At December 31, 2013, 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 2014	630,000	7,000	$105.67
Second Quarter 2014	409,500	4,500	110.48
Third Quarter 2014	644,000	7,000	108.24
Total	1,683,500		
Average price			$107.82

Subsequent to September 30, 2014, the Company entered into the following crude oil, diesel, jet fuel and gasoline swap contracts that offset derivative instruments existing at September 30, 2014.

Subsequent to September 30, 2014, the Company entered into the following derivatives related to crude oil sales in its fuel products segment, none of which are designated as hedges. As a result of this activity, the Company dedesignated the corresponding amount of crude oil swaps related to crude oil purchases for the corresponding periods.

Crude Oil Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
Fourth Quarter 2014	1,913,000	20,793	$85.93
Calendar Year 2015	1,719,000	4,710	84.26
Total	3,632,000		
Average price			$85.14

Subsequent to September 30, 2014, the Company entered into the following derivatives related to diesel purchases in its fuel products segment, none of which are designated as hedges. As a result of this activity, the Company dedesignated the corresponding amount of diesel swaps related to diesel sales for the corresponding periods.

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Diesel Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Swap ($/Bbl)
Fourth Quarter 2014	1,242,000	13,500	$ 107.48
Calendar Year 2015	1,449,000	3,970	105.78
Total	2,691,000		
Average price			$ 106.57

Subsequent to September 30, 2014, the Company entered into the following derivatives related to jet fuel purchases in its fuel products segment, none of which are designated as hedges. As a result of this activity, the Company dedesignated the corresponding amount of jet fuel swaps related to jet fuel sales for the corresponding periods.

Jet Fuel Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Swap ($/Bbl)
Fourth Quarter 2014	183,000	1,989	$ 100.78
Calendar Year 2015	270,000	740	100.87
Total	453,000		
Average price			$ 100.83

Subsequent to September 30, 2014, the Company entered into the following derivatives related to gasoline purchases in its fuel products segment, none of which are designated as hedges. As a result of this activity, the Company dedesignated the corresponding amount of gasoline swaps related to gasoline sales for the corresponding periods.

Gasoline Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Swap ($/Bbl)
Fourth Quarter 2014	488,000	5,304	$ 83.38
Total	488,000		
Average price			$ 83.38

11. 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

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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 September 30, 2014, the Company's net asset was reduced by $0.1 million and net liability was reduced by approximately $2.6 million. As a result of applying the CVA at December 31, 2013, the Company's net liability was reduced by approximately $1.9 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 10 for further information on derivative instruments.

Pension Assets

Pension assets are reported at fair value in the accompanying unaudited condensed consolidated financial statements. At September 30, 2014, 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 13 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 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.

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Hierarchy of Recurring Fair Value Measurements

The Company's recurring assets and liabilities measured at fair value at September 30, 2014 and December 31, 2013 were as follows (in millions):

	September 30, 2014				December 31, 2013			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Derivative assets:								
Crude oil swaps	$—	$—	$(22.6)	$(22.6)	$—	$—	$—	$—
Crude oil basis swaps	—	—	2.8	2.8	—	—	—	—
Gasoline swaps	—	—	23.6	23.6	—	—	—	—
Diesel swaps	—	—	47.3	47.3	—	—	—	—
Jet fuel swaps	—	—	6.0	6.0	—	—	—	—
Natural gas swaps	—	—	(2.3)	(2.3)	—	—	—	—
Total derivative assets	—	—	54.8	54.8	—	—	—	—
Pension plan investments	0.2	48.1	—	48.3	—	45.8	—	45.8
Total recurring assets at fair value	$0.2	$48.1	$54.8	$103.1	$—	$45.8	$—	$45.8
Liabilities:								
Derivative liabilities:								
Crude oil swaps	$—	$—	$—	$—	$—	$—	$37.0	$37.0
Crude oil basis swaps	—	—	—	—	—	—	0.4	0.4
Gasoline swaps	—	—	—	—	—	—	(28.1)	(28.1)
Diesel swaps	—	—	—	—	—	—	(50.6)	(50.6)
Jet fuel swaps	—	—	—	—	—	—	(12.4)	(12.4)
Diesel crack spread collars	—	—	—	—	—	—	0.1	0.1
Natural gas swaps	—	—	—	—	—	—	(1.2)	(1.2)
Interest rate swaps	—	—	(0.6)	(0.6)	—	—	—	—
Total derivative liabilities	—	—	(0.6)	(0.6)	—	—	(54.8)	(54.8)
RINs Obligation	—	(9.8)	—	(9.8)	—	(5.3)	—	(5.3)
Liability Awards	(5.0)	—	—	(5.0)	(3.7)	—	—	(3.7)
Total recurring liabilities at fair value	$(5.0)	$(9.8)	$(0.6)	$(15.4)	$(3.7)	$(5.3)	$(54.8)	$(63.8)

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 nine months ended September 30, 2014 and 2013 (in millions):

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	Nine Months Ended September 30,	
	2014	2013
Fair value at January 1,	$(54.8)	$(44.9)
Realized gain on derivative instruments	(17.7)	(5.4)
Unrealized gain on derivative instruments	22.6	22.9
Interest expense, net	(2.9)	—
Change in fair value of cash flow hedges	90.9	41.3
Settlements	16.1	6.8
Transfers in (out) of Level 3	—	—
Fair value at September 30,	$54.2	$20.7
Total gain included in net income (loss) attributable to changes in unrealized gain relating to financial assets and liabilities held as of September 30,	$22.6	$22.9

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 and natural gas 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 10 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. Refer to Note 4 for the fair values of assets acquired and liabilities assumed in connection with the Company’s acquisitions.

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 September 30, 2014 and December 31, 2013 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 capital lease obligations approximate their fair values as determined by discounted cash flows and are classified as Level 3. See Note 9 for further information on long-term debt.

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The Company's carrying and estimated fair value of the Company's financial instruments, carried at adjusted historical cost, at September 30, 2014 and December 31, 2013 were as follows (in millions):

		September 30, 2014		December 31, 2013	
	Level	Fair Value	Carrying Value	Fair Value	Carrying Value
Financial Instrument:					
Senior notes	1	$660.3	$ 615.7	$863.6	$ 761.2
Senior notes	2	$864.0	$ 900.0	$353.9	$ 344.8
Revolving credit facility	3	$124.2	$ 124.2	$—	$ —
Capital lease and other obligations	3	$43.8	$ 43.8	$4.8	$ 4.8

12. Partners' Capital

On March 10, 2014, the Company 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 contributed its proportionate capital contribution to retain its 2% general partner interest. For the three and nine months ended September 30, 2014, the Company sold 134,955 common units for net proceeds of $3.7 million. Underwriting discounts totaled $0.1 million and the Company's general partner contributed $0.1 million to maintain its general partner interest.

The Company's distribution policy is defined in its partnership agreement. For the three months ended September 30, 2014 and 2013, the Company made distributions of $52.5 million and $52.6 million, respectively, to its partners. For the nine months ended September 30, 2014 and 2013, the Company made distributions of $157.6 million and $149.0 million, respectively, to its partners.

For the three months ended September 30, 2014 and 2013, the general partner was allocated $3.8 million and $3.8 million, respectively, in incentive distribution rights. For the nine months ended September 30, 2014 and 2013, the general partner was allocated $11.5 million and $10.9 million, respectively, in incentive distribution rights.

13. Employee Benefit Plans

The components of net periodic pension benefit cost (income) for the three and nine months ended September 30, 2014 and 2013 were as follows (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Service cost	$0.1	$0.1	$0.3	$0.3
Interest cost	0.7	0.6	2.0	1.8
Expected return on assets	(0.8)	(1.2)	(2.3)	(2.2)
Amortization of net loss	—	0.1	0.2	0.5
Net periodic benefit cost (income)	$—	$(0.4)	$0.2	$0.4

At September 30, 2014 and December 31, 2013, 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 11 for the definitions of Levels 1, 2 and 3. The Company's pension plan assets measured at fair value at September 30, 2014 and December 31, 2013 were as follows (in millions):

	September 30, 2014		December 31, 2013	
	Level 1	Level 2	Level 1	Level 2
Cash and cash equivalents	$0.2	$—	$—	$—
Domestic equity funds	—	9.5	—	10.6
Foreign equity funds	—	9.5	—	10.6
Fixed income funds	—	29.1	—	24.6
	$0.2	$48.1	$—	$45.8

Investment Fund Strategies

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

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

14. 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 and nine months ended September 30, 2014 and 2013 (in millions):

Components of Accumulated Other Comprehensive Income (Loss)	Amount Reclassified From Accumulated Other Comprehensive Income (Loss)				Location of Gain (Loss)
	Three Months Ended September 30,		Nine Months Ended September 30,		
	2014	2013	2014	2013	
Derivative gains (losses) on cash flow hedges:					
	$(5.6)	$(4.7)	$(30.3)	$(1.4)	Sales
	12.1	10.3	34.0	(3.0)	Cost of sales
	$6.5	$5.6	$3.7	$(4.4)	Total
Amortization of defined benefit pension and postretirement health benefit plans:					
Amortization of net gain (loss)	$(0.1)	$0.1	$0.1	$(0.5)	[1]
	$(0.1)	$0.1	$0.1	$(0.5)	Total

(1) This accumulated other comprehensive income (loss) component is included in the computation of net periodic pension cost. See Note 13 for additional details.

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15. Earnings Per Unit

The following table sets forth the computation of basic and diluted earnings per limited partner unit for the three and nine months ended September 30, 2014 and 2013 (in millions, except unit and per unit data):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Numerator for basic and diluted earnings per limited partner unit:				
Net income (loss)	$9.4	$(34.8)	$(48.7)	$19.0
General partner's interest in net income (loss)	0.2	(0.7)	(1.0)	0.4
General partner's incentive distribution rights	3.8	3.8	11.5	10.9
Non-vested share based payments	—	—	—	0.2
Net income (loss) available to limited partners	$5.4	$(37.9)	$(59.2)	$7.5
Denominator for basic and diluted earnings per limited partner unit:				
Basic weighted average limited partner units outstanding	69,684,621	69,626,650	69,637,991	67,367,326
Effect of dilutive securities:				
Participating securities — phantom units	166,064	—	—	186,383
Diluted weighted average limited partner units outstanding [(1)]	69,850,685	69,626,650	69,637,991	67,553,709
Limited partners' interest basic and diluted net income (loss) per unit	$0.08	$(0.54)	$(0.85)	$0.11

[(1)] Total diluted weighted average limited partner units outstanding excludes 139,754 of dilutive phantom units for the nine months ended September 30, 2014. Total diluted weighted average limited partner units outstanding excludes 190,231 of dilutive phantom units for the three months ended September 30, 2013.

16. 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, drilling fluids 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.

During the fourth quarter 2013, the Company realigned its reportable segments for financial reporting purposes as a result of significant growth in the Company's business. The change primarily represents reporting the operating results of asphalt produced at the Shreveport, Superior and Montana refineries within the fuel products segment. Prior to this change, asphalt was reported as part of the specialty products segment. While this reporting change did not impact the Company's consolidated results, segment data for previous years has been restated and is consistent with the current year presentation throughout the unaudited condensed consolidated financial statements and the accompanying notes.

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 2013 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

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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.

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 and nine months ended September 30, 2014 and 2013 is as follows (in millions):

Three Months Ended September 30, 2014	Specialty Products	Fuel Products	Combined Segments	Eliminations	Consolidated Total
Sales:					
External customers	$587.4	$1,088.4	$1,675.8	$—	$1,675.8
Intersegment sales	3.2	23.4	26.6	(26.6)	—
Total sales	$590.6	$1,111.8	$1,702.4	$(26.6)	$1,675.8
Adjusted EBITDA	$80.1	$27.4	$107.5	—	$107.5
Reconciling items to net income:					
Depreciation and amortization	21.8	20.0	41.8	—	41.8
Realized loss on derivatives, not reflected in net income	(1.2)	(2.1)	(3.3)	—	(3.3)
Unrealized loss on derivatives					25.6
Interest expense					28.4
Debt extinguishment costs					0.3
Non-cash equity based compensation and other non-cash items					3.2
Income tax expense					2.1
Net income					$9.4

Three Months Ended September 30, 2013	Specialty Products	Fuel Products	Combined Segments	Eliminations	Consolidated Total
Sales:					
External customers	$434.8	$1,070.7	$1,505.5	$—	$1,505.5
Intersegment sales	—	16.1	16.1	(16.1)	—
Total sales	$434.8	$1,086.8	$1,521.6	$(16.1)	$1,505.5
Adjusted EBITDA	$46.0	$(7.7)	$38.3	—	$38.3
Less reconciling items to net loss:					
Depreciation and amortization	16.4	17.9	34.3	—	34.3
Realized gain on derivatives, not reflected in net loss	0.8	3.1	3.9	—	3.9
Unrealized gain on derivatives					(2.4)
Interest expense					24.2
Non-cash equity based compensation and other non-cash items					13.0

Income tax expense	0.1
Net loss	$(34.8)

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Nine Months Ended September 30, 2014	Specialty Products	Fuel Products	Combined Segments	Eliminations	Consolidated Total
Sales:					
External customers	$1,571.6	$2,880.1	$4,451.7	$—	$4,451.7
Intersegment sales	4.9	68.5	73.4	(73.4)	—
Total sales	$1,576.5	$2,948.6	$4,525.1	$(73.4)	$4,451.7
Adjusted EBITDA	$180.2	$49.3	$229.5	—	$229.5
Reconciling items to net loss:					
Depreciation and amortization	59.7	59.6	119.3	—	119.3
Realized gain on derivatives, not reflected in net income	—	0.1	0.1	—	0.1
Unrealized gain on derivatives					(22.6)
Interest expense					83.3
Debt extinguishment costs					89.9
Non-cash equity based compensation and other non-cash items					7.8
Income tax expense					0.4
Net loss					$(48.7)

Nine Months Ended September 30, 2013	Specialty Products	Fuel Products	Combined Segments	Eliminations	Consolidated Total
Sales:					
External customers	$1,355.2	$2,823.1	$4,178.3	$—	$4,178.3
Intersegment sales	—	55.2	55.2	(55.2)	—
Total sales	$1,355.2	$2,878.3	$4,233.5	$(55.2)	$4,178.3
Adjusted EBITDA	$152.0	$36.3	$188.3	—	$188.3
Reconciling items to net income:					
Depreciation and amortization	49.9	49.2	99.1	—	99.1
Realized gain on derivatives, not reflected in net income	0.5	2.5	3.0	—	3.0
Unrealized gain on derivatives					(22.9)
Interest expense					73.7
Non-cash equity based compensation and other non-cash items					15.9
Income tax expense					0.5
Net income					$19.0

b. Geographic Information

International sales accounted for less than 10% of consolidated sales in each of the three and nine months ended September 30, 2014 and 2013. Substantially all of the Company’s long-lived assets are domestically located.

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. The following table sets forth the major product category sales for the three months ended September 30, 2014 and 2013 (in millions):

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	Three Months Ended September 30,					
	2014			2013		
Specialty products:						
Lubricating oils	$200.3	12.0	%	$201.5	13.4	%
Solvents	126.0	7.5	%	127.5	8.5	%
Waxes	37.9	2.3	%	36.2	2.4	%
Packaged and synthetic specialty products	213.3	12.7	%	59.9	4.0	%
Other	9.9	0.6	%	9.7	0.6	%
Total	$587.4	35.1	%	$434.8	28.9	%
Fuel products:						
Gasoline	$408.5	24.4	%	$413.2	27.4	%
Diesel	330.6	19.7	%	347.8	23.1	%
Jet fuel	65.7	3.9	%	41.5	2.8	%
Asphalt, heavy fuel oils and other	283.6	16.9	%	268.2	17.8	%
Total	$1,088.4	64.9	%	$1,070.7	71.1	%
Consolidated sales	$1,675.8	100.0	%	$1,505.5	100.0	%

The following table sets forth the major product category sales for the nine months ended September 30, 2014 and 2013 (in millions):

	Nine Months Ended September 30,					
	2014			2013		
Specialty products:						
Lubricating oils	$583.1	13.1	%	$649.6	15.5	%
Solvents	377.6	8.5	%	387.2	9.3	%
Waxes	103.9	2.3	%	102.4	2.5	%
Packaged and synthetic specialty products	479.3	10.8	%	185.0	4.4	%
Other	27.7	0.6	%	31.0	0.7	%
Total	$1,571.6	35.3	%	$1,355.2	32.4	%
Fuel products:						
Gasoline	$1,126.4	25.3	%	$1,084.1	25.9	%
Diesel	916.0	20.6	%	956.3	22.9	%
Jet fuel	151.8	3.4	%	149.9	3.6	%
Asphalt, heavy fuel oils and other	685.9	15.4	%	632.8	15.2	%
Total	$2,880.1	64.7	%	$2,823.1	67.6	%
Consolidated sales	$4,451.7	100.0	%	$4,178.3	100.0	%

d. Major Customers

During the three and nine months ended September 30, 2014 and 2013, the Company had no customer that represented 10% or greater of consolidated sales.

e. Major Suppliers

During the three months ended September 30, 2014 and 2013, the Company had two suppliers that supplied approximately 46.7% and 56.5%, respectively, of its crude oil supply. During the nine months ended September 30, 2014 and 2013, the Company had two suppliers that supplied approximately 46.2% and 54.9%, respectively, of its crude oil supply.

17. Subsequent Events

On October 21, 2014, the Company declared a quarterly cash distribution of $0.685 per unit on all outstanding common units, or approximately $52.6 million (including the general partner’s incentive distribution rights) in aggregate, for the quarter ended September 30, 2014. The distribution will be paid on November 14, 2014 to unitholders of record as of the close of business on November 4, 2014. This quarterly distribution of $0.685 per unit equates to $2.74 per unit per year, or approximately $210.4 million (including the general partner’s incentive distribution rights) in aggregate on an annualized basis.

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The fair value of the Company’s derivatives increased by approximately $8.0 million subsequent to September 30, 2014 to a net asset of approximately $62.0 million. The fair value of the Company’s long-term debt, excluding capital leases, has increased by approximately $35.0 million subsequent to September 30, 2014.
On October 7, 2014, the Company received correspondence from the EPA evidencing the approval of a one-year extension of the small refinery exemption from the requirements of the Renewable Fuel Standard for its Shreveport and San Antonio refineries for the 2013 calendar year. As a result of the exemption, the Company’s requirements to purchase RINs for compliance in 2013 were reduced by approximately 39 million RINs. Any gains from these exemptions will be recorded in the fourth quarter, the period exemptions were received. At this time, the Company has not received exemptions related to RIN compliance for 2014 or beyond.

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

The historical unaudited condensed consolidated financial statements included in this Quarterly Report reflect all of the assets, liabilities and results of operations of Calumet Specialty Products Partners, L.P. ("Calumet," the "Company," "we," "our," or "us"). The following discussion analyzes the financial condition and results of operations of the Company for the three and nine months ended September 30, 2014 and 2013. Unitholders should read the following discussion and analysis of the financial condition and results of operations of the Company in conjunction with our 2013 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 based in Indianapolis, Indiana and own thirteen manufacturing facilities primarily located in northwest Louisiana, northwest Wisconsin, northern Montana, western Pennsylvania, Texas, New Jersey and Oklahoma. We own and lease additional facilities, primarily related to production and distribution of specialty and fuel products, throughout the United States ("U.S."). Our business is organized into two segments: specialty products and fuel products. 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, waxes and drilling fluids. 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 and Bel-Ray 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.

Third Quarter 2014 Update

Financial Results

We generated Adjusted EBITDA (as defined in "Non-GAAP Financial Measures") of $107.5 million during the third quarter 2014, compared to $38.3 million in the prior year period. The year-over-year increase in Adjusted EBITDA was driven by improved utilization at key fuels refineries, a year-over-year improvement in benchmark refining margins and strong demand for refined products.

Our specialty products segment generated a gross profit per barrel of $41.98 during the third quarter 2014, compared to $31.47 per barrel in the third quarter 2013. The increase in specialty products segment gross profit of $72.9 million was due primarily to incremental contributions from recently completed acquisitions, including Anchor Drilling Fluids ("Anchor"), Bel-Ray, Specialty Oilfield Services ("SOS") and United Petroleum, coupled with a decline in the average price per barrel of crude oil during the current year period.

Our fuel products segment generated gross profit of $3.11 per barrel (excluding hedging activities) during the third quarter 2014, compared to a gross loss of $(1.80) per barrel in the third quarter 2013. The increase in fuel products segment gross profit of $47.6 million was due primarily to improved refining economics, partially offset by higher RINs and natural gas costs incurred during the third quarter 2014 compared to the prior year period. Furthermore, during the third quarter 2014, we had limited downtime within our refining system, whereas in the prior year period we had an approximate 30-day planned turnaround at our Montana refinery. Following a period of significant maintenance related turnaround activity during 2013 and the first half of 2014 at our key fuel products refineries, we do not expect similar maintenance related activities to occur at these refineries until 2018. Given increased throughput rates within our fuel refining system during the third quarter 2014, we were able to capitalize on seasonally favorable benchmark fuels refining margins. Our fuel products refineries further benefited from sustained discounts on certain grades of North American crude oil processed primarily at our Montana and Superior refineries during the third quarter 2014, when compared to the prior year period.

The price of NYMEX West Texas Intermediate ("NYMEX WTI") crude oil declined during the third quarter 2014 and has since declined even more significantly early into the fourth quarter 2014. NYMEX WTI averaged $97 per barrel in the third quarter 2014 compared to $106 per barrel in the third quarter 2013. During October 2014, NYMEX WTI averaged $84 per barrel, as global crude oil prices have declined sharply due to a combination of geopolitical factors.

For benchmarking purposes, we compare our per barrel refined fuel products margin to the U.S. Gulf Coast 2/1/1 crack spread ("Gulf Coast crack spread"). The Gulf Coast crack spread represents the approximate gross margin per barrel that results from processing two barrels of crude oil into one barrel of gasoline and one barrel of ultra-low sulfur diesel fuel. The Gulf Coast crack spread is calculated using the 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 third quarter 2014, the Gulf Coast crack spread averaged approximately $19 per barrel, or approximately 12% higher than in the third quarter 2013. The benchmark diesel margin declined on a year over year basis during the third quarter 2014, although the gasoline crack spread increased by more than 35% when compared to the third quarter 2013. The Gulf Coast ULSD crack spread averaged approximately $20 per barrel during the third quarter 2014, compared to nearly $21 per barrel in the prior year period. The Gulf Coast gasoline crack spread averaged approximately $18 per barrel during the third quarter 2014, compared to nearly $13 per barrel in the prior year period. Our fuel products segment gross profit per barrel divided by the Gulf Coast crack spread is referred to as the "capture rate." The capture rate is a means of testing refinery system gross profit per barrel against the benchmark crack spread. In the third quarter 2014, our capture rate was approximately 16%, versus approximately (11)% in the third quarter 2013. Included within our fuel products segment gross profit per barrel calculation are the realized cost of crude oil and other feedstocks and other production-related expenses, the most significant portion of which includes labor, plant fuel, utilities, contract services, maintenance, depreciation and process materials. Our gross profit per barrel calculation may not be comparable to similar calculations published by our competitors.

There are several factors that impact our refined fuels product margin when compared to the benchmark cracks 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. 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 crack spread benchmark. Finally, some of our facilities, such as our Shreveport refinery, 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 fuels exclusively, such as our Montana, San Antonio and Superior refineries. Based on our system wide crude purchasing patterns and overall production slate, we believe the Gulf Coast crack spread remains a helpful indicator in tracking directional shifts in our refined product margins.

Liquidity Update

On September 30, 2014, we had availability under our revolving credit facility of approximately $557.4 million, based on an $831.5 million borrowing base, $149.9 million in outstanding standby letters of credit and $124.2 million in outstanding borrowings. In addition, we had $7.7 million of cash on hand as of September 30, 2014. 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.

Quarterly Cash Distribution

On October 21, 2014, we declared a quarterly cash distribution of $0.685 per unit, or $2.74 per unit on an annualized basis, for the quarter ended September 30, 2014 on all of our outstanding limited partner units. The distribution will be paid on November 14, 2014 to unitholders of record as of the close of business on November 4, 2014.

Renewable Fuels Standard Update

As set forth under the Renewable Fuels Standard ("RFS"), the EPA 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.

In late 2013, the EPA published proposed volume mandates for 2014, which are generally lower than the volumes for 2013 and lower than the statutory mandates. The EPA submitted a draft final rule for regulatory review by the federal Office of Management and Budget on August 21, 2014.

Renewable Identifications Numbers ("RINs") are a mechanism by which Obligated Blenders may demonstrate their compliance with the RVO, whereas the Obligated Blenders 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 their production pool each year, they must purchase and/or generate RINs to cover their blending obligation under the RFS. In conjunction with our ongoing compliance with the RFS, we 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 third quarter 2014, we incurred RFS compliance costs of $3.8 million compared to a $3.9 million gain for the third quarter 2013. We expect our gross estimated annual RINs obligation, which includes RINs that are required to be secured

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through either blending or the purchase of RINs in the open market, to be in the range of 85 million to 90 million RINs for the full year 2014. We continue to anticipate that expenses related to RFS compliance have the potential to remain a significant expense, assuming current market prices for RINs. Estimated RINs obligations are subject to fluctuations in fuels production volumes during the full-year 2014.

RFS Small Refinery Exemption

On October 7, 2014, the EPA granted both the Shreveport and San Antonio refineries a “small refinery exemption” under the RFS for the full-year 2013, as provided under the Clean Air Act. The EPA determined that for the full-year 2013, compliance with the RFS would represent a “disproportionate economic hardship” for these two refineries. Under the 2013 exemptions granted by the EPA, both the Shreveport and San Antonio refineries are not subject to the requirements of RFS as an “obligated party” for fuels produced at these refineries between January 1, 2013 and December 31, 2013. As a result of the exemptions, our requirements to purchase RINs for 2013 compliance were reduced by approximately 39 million RINs. Any gains from these exemptions will be recorded in the fourth quarter 2014, the period such exemptions were received. We are in the process of an assessment to determine which of our fuels refineries potentially could be eligible for economic hardship exemptions for the full-year 2014.

Organic Growth Projects Update

During 2013, we introduced a series of high-return organic growth projects requiring a total capital investment of approximately $610 million between 2013 and the first quarter of 2016.

Since 2013, we have invested over $300 million in these projects. During 2014, we estimate that our total capital investment on growth projects will approximate $315 million to $345 million. Upon completion, we estimate the incremental Adjusted EBITDA generated from these projects should result in highly attractive rates of return. Between 2014 and the first quarter of 2016, we intend to complete four major organic projects, including the following:

Dakota Prairie (North Dakota) Refinery. Together with our 50/50 joint venture partner, MDU Resources Group Inc. (“MDU”), we are in the process of constructing a 20,000 bpd diesel refinery located in Dickinson, North Dakota to meet growing local demand for finished products. The refinery, which is expected to be completely supplied with cost-advantaged local Bakken crude oil, is expected to be mechanically complete during the fourth quarter 2014. The estimated total construction cost of the expansion project to the joint venture is approximately $365 million, subject to periodic reviews of project costs.

Missouri Esters Plant Expansion Project. We have initiated a project designed to double esters production capacity at our Missouri esters plant from 35 million to 75 million pounds per year. We anticipate this project should reach completion during the second quarter 2015. Esters are a key base stock used in the aviation, refrigerant and automotive lubricants markets. The estimated total construction cost of the expansion project is approximately $40 million.

San Antonio Solvents Project. We have initiated a project that will take a portion of the San Antonio refinery’s diesel and jet fuel production and convert it into up to 3,000 bpd of higher margin solvent products that will meet customer requirements for low aromatic content. Solvents production will supplement the refinery’s current production slate and will be targeted toward the drilling fluid, paints and coating markets. This project is expected to reach completion during the second quarter 2015. The estimated total construction cost of the solvents project is approximately $40 million.

Montana Refinery Expansion Project. We have initiated a project designed to double production capacity at our Montana refinery by 10,000 bpd to 20,000 bpd. 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 regional markets. The scope of this project calls for the installation of a new 20,000 bpd crude unit and a 25,000 bpd hydrocracker. We estimate this project will be completed during the first quarter 2016. The estimated total construction cost of the expansion project is approximately $400 million.

Hedging Update

Subsequent to September 30, 2014, we entered into crude oil, diesel, jet fuel and gasoline swap contracts that offset derivative instruments existing at September 30, 2014 in order to lock in hedging gains on 3.6 million barrels which will be realized during the fourth quarter 2014 and in 2015. Please read Part I, Item 3 “Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk” for additional details.

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Key Performance Measures

Our sales and net income are principally affected by the price of crude oil, demand for specialty and fuel products and other process-critical feedstocks, 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 and fuel products. The prices of crude oil, specialty products and fuel products 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 September 30, 2014, we had hedged refining margins, or crack spreads, on approximately 12.5 million barrels of fuel products through December 2016 at an average refining margin of $24.75 per barrel with average refining margins ranging from a low of $20.64 per barrel in the fourth quarter 2014 to a high of $27.23 per barrel in 2016. Please refer to Note 10 — “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 and fuel products segment gross profit; and
- specialty products and fuel products 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 and fuel products segment gross profit. Specialty products and fuel products gross profit are important measures of our ability to maximize the profitability of our specialty products and fuel products segments. We define specialty products and fuel products gross profit as sales less the cost of crude oil and other feedstocks and other production-related expenses, the most significant portion of which includes labor, plant fuel, utilities, contract services, maintenance, depreciation and processing materials. We use specialty products and fuel products gross profit as indicators 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 throughput volumes, but can fluctuate depending on maintenance activities performed during a specific period.

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 and fuel products segment Adjusted EBITDA. We believe that specialty products and fuel products 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.

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Results of Operations for the Three and Nine Months Ended September 30, 2014 and 2013

Production Volume. The following table sets forth information about our combined operations, excluding Anchor and SOS operations. 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 at our San Antonio refinery commencing January 2, 2013, Bel-Ray facility commencing December 10, 2013 and United Petroleum assets commencing February 28, 2014.

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2014	2013	% Change	2014	2013	% Change
	(In bpd)			(In bpd)		
Total sales volume [1]	136,315	128,576	6.0 %	122,821	118,967	3.2 %
Total feedstock runs [2]	125,289	117,996	6.2 %	118,446	112,485	5.3 %
Facility production: [3]						
Specialty products:						
Lubricating oils	14,303	13,093	9.2 %	11,971	13,248	(9.6)%
Solvents	8,836	8,156	8.3 %	8,958	8,725	2.7 %
Waxes	1,538	1,426	7.9 %	1,319	1,324	(0.4)%
Packaged and synthetic specialty products [4]	1,904	2,344	(18.8)%	1,785	2,190	(18.5)%
Other	1,307	3,531	(63.0)%	1,905	2,512	(24.2)%
Total	27,888	28,550	(2.3)%	25,938	27,999	(7.4)%
Fuel products:						
Gasoline	36,651	31,140	17.7 %	33,130	29,243	13.3 %
Diesel	28,540	29,594	(3.6)%	26,359	26,076	1.1 %
Jet fuel	5,901	4,251	38.8 %	4,729	4,761	(0.7)%
Asphalt, heavy fuels and other	21,239	21,067	0.8 %	22,510	21,412	5.1 %
Total	92,331	86,052	7.3 %	86,728	81,492	6.4 %
Total facility production [3]	120,219	114,602	4.9 %	112,666	109,491	2.9 %

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(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 September 30, 2014 compared to the same period in 2013 is due primarily to increased production at the Shreveport refinery, increased production at the Montana refinery as a result of turnaround activity in the 2013 period, increased production at the San Antonio refinery as a result of the crude oil unit expansion completed in December 2013 and incremental sales volume from the Bel-Ray Acquisition.

The increase in total sales volume for the nine months ended September 30, 2014 compared to the same period in 2013 is due primarily to increased production at the Montana and Superior refineries as a result of turnaround activity in the 2013 period, increased production at the San Antonio refinery as a result of the crude oil unit expansion completed in December 2013 and incremental sales volume from the Bel-Ray Acquisition, partially offset by decreased production at the Shreveport refinery as a result of extended turnaround activity in the 2014 period.

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

The increase in total feedstock runs for the three months ended September 30, 2014 compared to the same period in 2013 is due primarily to increased feedstock runs at the Shreveport refinery, increased feedstock runs in the 2014 period at the Montana refinery as a result of turnaround activity in the 2013 period, increased feedstock runs at the San Antonio refinery as a result of the crude oil unit expansion completed in December 2013 and incremental production volume from the Bel-Ray Acquisition.

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The increase in total feedstock runs for the nine months ended September 30, 2014 compared to the same period in 2013 is due primarily to increased feedstock runs at the Superior refinery in 2014 as a result of turnaround activity in the 2013 period, increased feedstock runs at the Montana refinery in 2014 as a result of turnaround activity in the 2013 period, incremental feedstock runs as a result of the Bel-Ray Acquisition and incremental feedstock runs in 2014 as a result of the San Antonio crude oil unit expansion completed in December 2013, partially offset by decreased feedstock runs at the Shreveport refinery as a result of extended turnaround activity in the 2014 period.

(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 and nine months ended September 30, 2014 compared to the same periods in 2013 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 (used in) operating activities, our most directly comparable financial performance and liquidity measures calculated and presented in accordance with GAAP, please read "—Non-GAAP Financial Measures."

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(In millions)			
Sales	$1,675.8	$1,505.5	$4,451.7	$4,178.3
Cost of sales	1,493.2	1,443.4	4,045.3	3,880.8
Gross profit	182.6	62.1	406.4	297.5
Operating costs and expenses:				
Selling	43.6	13.9	103.3	46.7
General and administrative	26.5	15.8	73.3	59.9
Transportation	42.2	34.9	123.9	104.1
Taxes other than income taxes	4.2	3.7	9.9	9.7
Other	4.7	12.8	9.6	14.4
Operating income (loss)	61.4	(19.0)	86.4	62.7
Other income (expense):				
Interest expense	(28.4)	(24.2)	(83.3)	(73.7)
Debt extinguishment costs	(0.3)	—	(89.9)	—
Realized gain on derivative instruments	5.1	4.2	17.7	5.4
Unrealized gain (loss) on derivative instruments	(25.6)	2.4	22.6	22.9
Other	(0.7)	1.9	(1.8)	2.2
Total other expense	(49.9)	(15.7)	(134.7)	(43.2)
Net income (loss) before income taxes	11.5	(34.7)	(48.3)	19.5
Income tax expense	2.1	0.1	0.4	0.5
Net income (loss)	$9.4	$(34.8)	$(48.7)	$19.0
EBITDA	$75.6	$18.9	$225.9	$181.4
Adjusted EBITDA	$107.5	$38.3	$229.5	$188.3
Distributable Cash Flow	$71.3	$(16.0)	$104.7	$7.9

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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.

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 2020 Notes, 2021 Notes and 2022 Notes (as defined in this Quarterly Report). We are required to report Consolidated Cash Flow to the holders of our 2020 Notes, 2021 Notes and 2022 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 (used in) 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 September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(In millions)			
Reconciliation of Net income (loss) to EBITDA, Adjusted EBITDA and Distributable Cash Flow:				
Net income (loss)	$9.4	$(34.8)	$(48.7)	$19.0
Add:				
Interest expense	28.4	24.2	83.3	73.7
Debt extinguishment costs	0.3	—	89.9	—
Depreciation and amortization	35.4	29.4	101.0	88.2
Income tax expense	2.1	0.1	0.4	0.5
EBITDA	$75.6	$18.9	$225.9	$181.4
Add:				
Unrealized (gain) loss on derivative instruments	$25.6	$(2.4)	$(22.6)	$(22.9)
Realized gain (loss) on derivatives, not included in net income (loss)	(3.3)	3.9	0.1	3.0
Amortization of turnaround costs	6.4	4.9	18.3	10.9
Non-cash equity based compensation and other non-cash items	3.2	13.0	7.8	15.9
Adjusted EBITDA	$107.5	$38.3	$229.5	$188.3
Less:				
Replacement and environmental capital expenditures [1]	$6.9	$15.8	$23.6	$48.5
Cash interest expense [2]	26.8	22.5	78.2	68.5
Turnaround costs	0.4	15.9	22.6	62.9
Income tax expense	2.1	0.1	0.4	0.5
Distributable Cash Flow	$71.3	$(16.0)	$104.7	$7.9

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

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

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	Nine Months Ended September 30, 2014	2013
	(In millions)	
Reconciliation of Distributable Cash Flow, Adjusted EBITDA and EBITDA to Net cash provided by operating activities:		
Distributable Cash Flow	$104.7	$7.9
Add:		
Replacement and environmental capital expenditures (1)	23.6	48.5
Cash interest expense (2)	78.2	68.5
Turnaround costs	22.6	62.9
Income tax expense	0.4	0.5
Adjusted EBITDA	$229.5	$188.3
Less:		
Unrealized gain on derivative instruments	(22.6)	(22.9)
Realized gain on derivatives, not included in net income (loss)	0.1	3.0
Amortization of turnaround costs	18.3	10.9
Non-cash equity based compensation and other non-cash items	7.8	15.9
EBITDA	$225.9	$181.4
Add:		
Unrealized gain on derivative instruments	(22.6)	(22.9)
Cash interest expense (2)	(78.2)	(68.5)
Non-cash equity based compensation	7.8	15.9
Amortization of turnaround costs	18.3	10.9
Income tax expense	(0.4)	(0.5)
Provision for doubtful accounts	0.8	0.6
Debt extinguishment costs	(70.9)	—
Changes in assets and liabilities:		
Accounts receivable	(112.2)	(75.8)
Inventories	(9.1)	10.9
Other current assets	(3.4)	4.9
Turnaround costs	(22.6)	(62.9)
Derivative activity	0.2	3.0
Other assets	—	0.1
Accounts payable	108.6	121.7
Accrued interest payable	19.9	5.3
Accrued income taxes payable	—	(27.6)
Other current liabilities	(4.9)	14.2
Other, including changes in noncurrent liabilities	1.3	(0.4)
Net cash provided by operating activities	$58.5	$110.3

(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 September 30, 2014 and 2013

Sales. Sales increased $170.3 million, or 11.3%, to $1,675.8 million in the three months ended September 30, 2014 from $1,505.5 million in the same period in 2013. The results of operations related to the San Antonio and Crude Oil Logistics Acquisitions have been included in the fuel products segment since their dates of acquisition, January 2, 2013 and August 9, 2013, respectively. The results of operations related to the Bel-Ray, United Petroleum, Anchor and SOS Acquisitions have been included in the specialty products segment since their dates of acquisition, December 10, 2013, February 28, 2014, March 31, 2014 and August 1, 2014, respectively. Volumetric and per barrel data excludes oil field services activity for Anchor and SOS. Sales for each of our principal product categories in these periods were as follows:

	Three Months Ended September 30,		
	2014	2013	% Change
	(Dollars in millions, except barrel and per barrel data)		
Sales by segment:			
Specialty products:			
Lubricating oils	$200.3	$201.5	(0.6)%
Solvents	126.0	127.5	(1.2)%
Waxes	37.9	36.2	4.7%
Packaged and synthetic specialty products [(1)]	213.3	59.9	256.1%
Other [(2)]	9.9	9.7	2.1%
Total specialty products	$587.4	$434.8	35.1%
Total specialty products sales volume (in barrels)	2,368,000	2,313,000	2.4%
Average specialty products sales price per barrel	$192.65	$187.98	2.5%
Fuel products:			
Gasoline	$412.3	$413.3	(0.2)%
Diesel	332.2	352.4	(5.7)%
Jet fuel	65.9	41.5	58.8%
Asphalt, heavy fuel oils and other [(3)]	283.6	268.2	5.7%
Hedging activities loss	(5.6)	(4.7)	19.1%
Total fuel products	$1,088.4	$1,070.7	1.7%
Total fuel products sales volume (in barrels)	10,173,000	9,516,000	6.9%
Average fuel products sales price per barrel (excluding hedging activities)	$107.54	$113.01	(4.8)%
Average fuel products sales price per barrel (including hedging activities)	$106.99	$112.52	(4.9)%
Total sales	$1,675.8	$1,505.5	11.3%
Total sales volume (in barrels)	12,541,000	11,829,000	6.0%

(1) Represents packaged and synthetic specialty products at the Royal Purple, Anchor, Bel-Ray, Calumet Packaging, Missouri and SOS facilities. Includes approximately $16.8 million of service revenue for the three months ended September 30, 2014.

(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 and San Antonio refineries to third party customers.

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The components of the $152.6 million specialty products segment sales increase in the three months ended September 30, 2014 were as follows:

	Dollar Change (In millions)
Acquisitions	$ 148.0
Volume	3.9
Sales price	0.7
Total specialty products segment sales increase	$ 152.6

Specialty products segment sales increased $152.6 million quarter over quarter, or 35.1%, primarily as a result of $148.0 million of incremental sales from the Anchor, Bel-Ray, SOS and United Petroleum Acquisitions and increased sales volume. Legacy operations' sales volumes increased 0.9% as compared to the same period in 2013, which resulted in a $3.9 million increase in sales. The increase in sales volume is due primarily to higher sales volumes of solvents and packaged and synthetic specialty products. Legacy operations' sales price increased $0.7 million compared to the third quarter 2013 due to a 0.2% increase in the average selling price per barrel primarily as a result of improved product mix.

The components of the $17.7 million fuel products segment sales increase for the three months ended September 30, 2014 were as follows:

	Dollar Change (In millions)
Volume	$ 74.4
Hedging activities	(0.9)
Sales price	(55.8)
Total fuel products segment sales increase	$ 17.7

Fuel products segment sales increased $17.7 million quarter over quarter, or 1.7%, primarily due to increased volume, partially offset by a decrease in the average selling price per barrel and a $0.9 million increase in realized derivative losses recorded in sales on our fuel products cash flow hedges. Sales volumes increased 6.9% primarily due to increased sales volume of gasoline, jet fuel and asphalt primarily as a result of increased production at the Montana refinery due to turnaround activity in the 2013 period and increased production at the San Antonio refinery as a result of the crude oil unit expansion completed in December 2013. The average selling price per barrel (excluding the impact of hedging activities reflected in sales) decreased $5.47, or 4.8%, resulting in a $55.8 million decrease in sales, compared to a 12.0% decrease in the average price of crude oil per barrel. The decrease in the average selling price per barrel is primarily due to lower gasoline and diesel average selling prices per barrel as a result of market conditions.

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Gross Profit. Gross profit increased $120.5 million, or 194.0%, to $182.6 million in the three months ended September 30, 2014 from $62.1 million in the same period in 2013. Gross profit for our specialty products and fuel products segments were as follows:

	Three Months Ended September 30,		
	2014	2013	% Change
	(Dollars in millions, except per barrel data)		
Gross profit by segment:			
Specialty products:			
Gross profit	$145.7	$72.8	100.1 %
Percentage of sales	24.8 %	16.7 %	
Specialty products gross profit per barrel	$41.98	$31.47	33.4 %
Fuel products:			
Gross profit (loss) excluding hedging activities	$31.6	$(17.1)	(284.8)%
Hedging activities	5.3	6.4	(17.2)%
Gross profit (loss)	$36.9	$(10.7)	(444.9)%
Percentage of sales	3.4 %	(1.0)%	
Fuel products gross profit (loss) per barrel (excluding hedging activities)	$3.11	$(1.80)	(272.8)%
Fuel products gross profit (loss) per barrel (including hedging activities)	$3.63	$(1.12)	(424.1)%
Total gross profit	$182.6	$62.1	194.0 %
Percentage of sales	10.9 %	4.1 %	

The components of the $72.9 million specialty products segment gross profit increase for the three months ended September 30, 2014 were as follows:

	Dollar Change (In millions)
Quarter ended September 30, 2013 reported gross profit	$72.8
Acquisitions	51.3
Cost of materials	17.2
Operating costs	2.7
Sales price	0.7
Volume	1.0
Quarter ended September 30, 2014 reported gross profit	$145.7

The increase in specialty products segment gross profit of $72.9 million quarter over quarter was due primarily to incremental gross profit of $51.3 million generated from the Anchor, Bel-Ray, SOS and United Petroleum Acquisitions and a decrease in the average cost of crude oil per barrel. Sales price and cost of materials, net, from our legacy operations increased gross profit by $17.9 million, as the average cost of crude oil per barrel decreased 9.0% and the average selling price per barrel increased 0.2%.

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The components of the $47.6 million fuel products segment gross profit increase for the three months ended September 30, 2014 were as follows:

	Dollar Change (In millions)
Quarter ended September 30, 2013 reported gross loss	$(10.7)
Cost of materials	116.9
Volume	3.6
Sales price	(55.8)
Operating costs	(16.0)
Hedging activities	(1.1)
Quarter ended September 30, 2014 reported gross profit	$36.9

The increase in fuel products segment gross profit of $47.6 million quarter over quarter was due primarily to increased gross profit as a result of widening crack spreads as the decrease in the average cost of crude oil per barrel outpaced the decrease in the average selling price per barrel. Additionally, operating costs increased $16.0 million primarily as a result of a $7.7 million increase in RINs costs and natural gas costs.

Selling. Selling expenses increased $29.7 million, or 213.7%, to $43.6 million in the three months ended September 30, 2014 from $13.9 million in the same period in 2013. The increase was due primarily to incremental selling expenses related to the Anchor, Bel-Ray and SOS Acquisitions and a $3.4 million increase in advertising expenses.

General and administrative. General and administrative expenses increased $10.7 million, or 67.7%, to $26.5 million in the three months ended September 30, 2014 from $15.8 million in the same period in 2013. The increase was due primarily to incremental general and administrative expenses related to the Anchor, Bel-Ray and SOS Acquisitions, a $6.6 million increase in incentive compensation costs, a $1.3 million increase in information technology related expenses and a $0.5 million increase in professional fees expense.

Transportation. Transportation expenses increased $7.3 million, or 20.9%, to $42.2 million in the three months ended September 30, 2014 from $34.9 million in the same period in 2013. This increase was due primarily to incremental transportation expenses related to the Anchor and Bel-Ray Acquisitions and increased crude oil sales to third parties, partially offset by lower lubricating oil sales volumes.

Other operating costs and expenses. Other operating costs and expenses decreased $8.1 million, or 63.3%, to $4.7 million in the three months ended September 30, 2014 from $12.8 million in the same period in 2013. The decrease was due primarily to a non-cash charge of $10.5 million related to a write-down of unutilized fixed assets in the prior year, with no similar expenses in the current year, partially offset by increased environmental cleanup expenses.

Interest expense. Interest expense increased $4.2 million, or 17.4%, to $28.4 million in the three months ended September 30, 2014 from $24.2 million in the same period in 2013, due primarily to additional outstanding long-term debt in the form of 2022 and 2021 Notes, partially offset by the redemption of the 2019 Notes.

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 September 30, 2014 and 2013:

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	Three Months Ended September 30,	
	2014	2013
	(In millions)	
Derivative loss reflected in sales	$(5.6)	$(4.7)
Derivative gain reflected in cost of sales	12.1	10.3
Derivative gains reflected in gross profit	$6.5	$5.6
Realized gain on derivative instruments	$5.1	$4.2
Unrealized gain (loss) on derivative instruments	(25.6)	2.4
Derivative gain reflected in interest expense	0.9	—
Total derivative gain (loss) reflected in the unaudited condensed consolidated statements of operations	$(13.1)	$12.2
Total gain on commodity derivative settlements	$8.1	$13.7

Realized gain on derivative instruments. Realized gain on derivative instruments increased $0.9 million to $5.1 million in the three months ended September 30, 2014 from $4.2 million in the prior period. The change was due primarily to approximately $0.9 million in increased hedging ineffectiveness related to cash flow hedges.

Unrealized gain (loss) on derivative instruments. Unrealized gain (loss) on derivative instruments decreased $28.0 million to a $25.6 million loss in the three months ended September 30, 2014 from a gain of $2.4 million in the prior period. The change is due primarily to decreased gain ineffectiveness of approximately $35.1 million partially offset by increased unrealized gains of approximately $7.1 million related to derivative instruments used to economically hedge crack spreads that are not accounted for as hedges for accounting purposes.

Income tax expense. Income tax expense increased $2.0 million to $2.1 million in the three months ended September 30, 2014 from $0.1 million in the prior period. The change was due primarily to the Anchor Acquisition, which increased the proportion of earnings subject to federal, state and local income taxes.

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Changes in Results of Operations for the Nine Months Ended September 30, 2014 and 2013

Sales. Sales increased $273.4 million, or 6.5%, to $4,451.7 million in the nine months ended September 30, 2014 from $4,178.3 million in the same period in 2013. The results of operations related to the San Antonio and Crude Oil Logistics Acquisitions have been included in the fuel products segment since their dates of acquisition, January 2, 2013 and August 9, 2013, respectively. The results of operations related to the Bel-Ray, United Petroleum, Anchor, and SOS Acquisitions have been included in the specialty products segment since their dates of acquisition, December 10, 2013, February 28, 2014, March 31, 2014, and August 1, 2014, respectively. Volumetric and per barrel data excludes oil field services activity for Anchor and SOS. Sales for each of our principal product categories in these periods were as follows:

	Nine Months Ended September 30,		
	2014	2013	% Change
	(Dollars in millions, except barrel and per barrel data)		
Sales by segment:			
Specialty products:			
Lubricating oils	$583.1	$649.6	(10.2)%
Solvents	377.6	387.2	(2.5)%
Waxes	103.9	102.4	1.5%
Packaged and synthetic specialty products [1]	479.3	185.0	159.1%
Other [2]	27.7	31.0	(10.6)%
Total specialty products	$1,571.6	$1,355.2	16.0%
Total specialty products sales volume (in barrels)	6,843,000	7,335,000	(6.7)%
Average specialty products sales price per barrel	$194.45	$184.76	5.2%
Fuel products:			
Gasoline	$1,141.7	$1,084.3	5.3%
Diesel	930.2	958.8	(3.0)%
Jet fuel	152.6	148.6	2.7%
Asphalt, heavy fuel oils and other [3]	685.9	632.8	8.4%
Hedging activities loss	(30.3)	(1.4)	2,064.3%
Total fuel products	$2,880.1	$2,823.1	2.0%
Total fuel products sales volume (in barrels)	26,687,000	25,143,000	6.1%
Average fuel products sales price per barrel (excluding hedging activities)	$109.06	$112.34	(2.9)%
Average fuel products sales price per barrel (including hedging activities)	$107.92	$112.28	(3.9)%
Total sales	$4,451.7	$4,178.3	6.5%
Total sales volume (in barrels)	33,530,000	32,478,000	3.2%

(1) Represents packaged and synthetic specialty products at the Royal Purple, Anchor, Bel-Ray, Calumet Packaging, Missouri and SOS facilities. Includes approximately $26.1 million of service revenue for the nine months ended September 30, 2014.

(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 and San Antonio refineries to third party customers.

The components of the $216.4 million specialty products segment sales increase in the nine months ended September 30, 2014 were as follows:

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	Dollar Change (In millions)
Acquisitions	$284.6
Sales Price	37.5
Volume	(105.7)
Total specialty products segment sales increase	$216.4

Specialty products segment sales increased $216.4 million, or 16.0%, period over period, primarily as a result of $284.6 million of incremental sales from the Anchor, Bel-Ray, SOS and United Petroleum Acquisitions and an increase in the average selling price per barrel, partially offset by lower sales volume. Legacy operations' sales increased $37.5 million compared to the third quarter 2013 due to a 3.0% increase in the average selling price per barrel primarily as a result of higher lubricating oil sales prices and improved product mix. Legacy operations' sales volumes decreased 7.8% as compared to the same period in 2013, which resulted in a $105.7 million decrease in sales. The decrease in sales volume is due primarily to lower sales volumes of lubricating oils at the Shreveport refinery due to extended turnaround activity in 2014, partially offset by increased sales volumes of packaged and synthetic specialty products.

The components of the $57.0 million fuel products segment sales increase for the nine months ended September 30, 2014 were as follows:

	Dollar Change (In millions)
Volume	$173.5
Sales price	(87.6)
Hedging activities	(28.9)
Total fuel products segment sales increase	$57.0

Fuel products segment sales increased $57.0 million period over period, or 2.0%, primarily due to increased sales volume, partially offset by a decrease in the average selling price per barrel and a $28.9 million increase in realized derivative losses recorded in sales on our fuel products cash flow hedges. Sales volumes increased 6.1% primarily due to increased sales volume of gasoline, heavy fuel oil and jet fuel, as a result of increased production at our Superior and Montana refineries due to turnaround activity in the 2013 period and increased production at the San Antonio refinery as a result of the crude oil unit expansion completed in December 2013, partially offset by decreased production at the Shreveport refinery due to extended turnaround activity in the 2014 period. The average selling price per barrel (excluding the impact of hedging activities reflected in sales) decreased $3.28, or 2.9%, resulting in an $87.6 million decrease in sales, compared to a 2.4% decrease in the average price of crude oil per barrel. The decrease in the average selling price per barrel is primarily due to lower gasoline and diesel average selling prices per barrel as a result of market conditions.

Gross Profit. Gross profit increased $108.9 million, or 36.6%, to $406.4 million in the nine months ended September 30, 2014 from $297.5 million in the same period in 2013. Gross profit for our specialty products and fuel products segments were as follows:

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	Nine Months Ended September 30,		
	2014	2013	% Change
	(Dollars in millions, except per barrel data)		
Gross profit by segment:			
Specialty products:			
Gross profit	$346.6	$243.2	42.5 %
Percentage of sales	22.1 %	17.9 %	
Specialty products gross profit per barrel	$39.13	$33.16	18.0 %
Fuel products:			
Gross profit excluding hedging activities	$56.1	$58.2	(3.6)%
Hedging activities	3.7	(3.9)	(194.9)%
Gross profit	$59.8	$54.3	10.1 %
Percentage of sales	2.1 %	1.9 %	
Fuel products gross profit per barrel (excluding hedging activities)	$2.10	$2.31	(9.1)%
Fuel products gross profit per barrel (including hedging activities)	$2.24	$2.16	3.7 %
Total gross profit	$406.4	$297.5	36.6 %
Percentage of sales	9.1 %	7.1 %	

The components of the $103.4 million specialty products segment gross profit increase for the nine months ended September 30, 2014 were as follows:

	Dollar Change
	(In millions)
Nine months ended September 30, 2013 reported gross profit	$243.2
Acquisitions	92.1
Sales price	37.5
Operating costs	2.1
Cost of materials	1.8
Volume	(30.1)
Nine months ended September 30, 2014 reported gross profit	$346.6

The increase in specialty products segment gross profit of $103.4 million for the nine months ended September 30, 2014 compared to the same period in 2013 was due primarily to incremental gross profit of $92.1 million generated from the Anchor, Bel-Ray, SOS and United Petroleum Acquisitions and increased selling prices per barrel, partially offset by decreased sales volume. Additionally, sales price and cost of materials, net, from our legacy operations increased gross profit by $39.3 million, as the average selling price per barrel increased 3.0%, while the average cost of crude oil per barrel decreased 2.8% due to improved product mix as a result of higher lubricating oils and packaged and synthetic specialty products sales.

The components of the $5.5 million fuel products segment gross profit increase for the nine months ended September 30, 2014 were as follows:

	Dollar Change
	(In millions)
Nine months ended September 30, 2013 reported gross profit	$54.3
Cost of materials	90.5
Volume	17.9
Hedging activities	7.6
Sales price	(87.6)
Operating costs	(22.9)
Nine months ended September 30, 2014 reported gross profit	$59.8

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The increase in fuel products segment gross profit of $5.5 million for the nine months ended September 30, 2014 compared to the same period in 2013 was due primarily to increased gross profit as a result of a $7.6 million decrease in realized losses on derivatives, partially offset by higher operating costs. Operating costs increased $22.9 million due primarily to higher natural gas prices and higher repair and maintenance costs. During the 2014 period, crack spreads narrowed as the average cost of crude oil per barrel decreased 2.4% and the average selling price per barrel decreased by 2.9%.

Selling. Selling expenses increased $56.6 million, or 121.2%, to $103.3 million in the nine months ended September 30, 2014 from $46.7 million in the same period in 2013. The increase was due primarily to incremental selling expenses related to the Anchor, Bel-Ray and SOS Acquisitions, a $2.3 million increase in advertising expense and a $0.5 million increase in professional fees expense.

General and administrative. General and administrative expenses increased $13.4 million, or 22.4%, to $73.3 million in the nine months ended September 30, 2014 from $59.9 million in the same period in 2013. The increase was due primarily to incremental general and administrative expenses related to the Anchor, Bel-Ray and SOS Acquisitions, a $7.0 million increase in incentive compensation costs, a $2.3 million increase in information technology related expenses and $1.2 million increase in professional fees expense.

Transportation. Transportation expenses increased $19.8 million, or 19.0%, to $123.9 million in the nine months ended September 30, 2014 from $104.1 million in the same period in 2013. This increase was due primarily to incremental transportation expenses related to the Anchor, Bel-Ray and SOS Acquisitions and increased crude oil sales to third parties, partially offset by decreased lubricating oil sales.

Other operating costs and expenses. Other operating costs and expenses decreased $4.8 million, or 33.3%, to $9.6 million in the nine months ended September 30, 2014 from $14.4 million in the same period in 2013. The decrease was due primarily to a non-cash charge of $10.5 million related to a write-down of unutilized fixed assets in the prior year, with no similar expenses in the current year, partially offset by increased environmental cleanup expenses.

Interest expense. Interest expense increased $9.6 million, or 13.0%, to $83.3 million in the nine months ended September 30, 2014 from $73.7 million in the same period in 2013, due primarily to additional outstanding long-term debt in the form of 2022 and 2021 Notes, partially offset by the redemption of the 2019 Notes.

Debt extinguishment costs. Debt extinguishment costs were $89.9 million in the nine months ended September 30, 2014. Debt extinguishment costs were due primarily to the redemption of the remaining 2019 Notes with a portion of the net proceeds from the issuance of the 2021 Notes.

Derivative activity. The following table details the impact of our derivative instruments on the unaudited condensed consolidated statements of operations for the nine months ended September 30, 2014 and 2013:

	Nine Months Ended September 30,	
	2014	2013
	(In millions)	
Derivative loss reflected in sales	$(30.3)	$(1.4)
Derivative gain (loss) reflected in cost of sales	34.0	(3.0)
Derivative gains (losses) reflected in gross profit	$3.7	$(4.4)
Realized gain on derivative instruments	$17.7	$5.4
Unrealized gain on derivative instruments	22.6	22.9
Derivative gain reflected in interest expense	2.2	—
Total derivative gain reflected in the unaudited condensed consolidated statements of operations	$46.2	$23.9
Total gain on commodity derivative settlements	$21.5	$4.0

Realized gain on derivative instruments. Realized gain on derivative instruments increased $12.3 million to $17.7 million in the nine months ended September 30, 2014 from $5.4 million in the prior period. The change was due primarily to approximately $11.2 million in increased hedging ineffectiveness related to settlements of cash flow hedges.

Unrealized gain on derivative instruments. Unrealized gain on derivative instruments decreased $0.3 million to $22.6 million in the nine months ended September 30, 2014 from $22.9 million in the prior period. The change is due primarily to decreased gain ineffectiveness of approximately $11.8 million, offset by increased unrealized gains of approximately $11.8

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million related to derivative instruments used to economically hedge crack spreads that are not accounted for as hedges for accounting purposes.

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.

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 2013 Annual Report. There have been no material changes in that information other than as discussed below. Also, see Note 9 — "Long-Term Debt" and Note 6— "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.

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 and borrowings under our revolving credit facility. 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 and borrowing capacity 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:

	Nine Months Ended September 30,	
	2014	2013
	(In millions)	

Net cash provided by operating activities	$58.5	$110.3
Net cash used in investing activities	(518.6)	(256.0)
Net cash provided by financing activities	346.7	247.4
Net increase (decrease) in cash and cash equivalents	$(113.4)	$101.7

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Operating Activities. Cash provided by operating activities decreased to $58.5 million during the nine months ended September 30, 2014 compared to $110.3 million during the same period in 2013. The change is due primarily to decreased net income of $67.7 million, partially offset by decreased working capital requirements, primarily turnaround costs and accrued income taxes payable.

Investing Activities. Cash used in investing activities increased to $518.6 million during the nine months ended September 30, 2014 compared to $256.0 million during the prior year period. The increase is due primarily to the higher combined purchase price of $263.6 million for the Anchor, United Petroleum and SOS Acquisitions, which closed in 2014, compared to the purchase price of $124.1 million for the San Antonio Acquisition which closed in 2013, an increase in capital expenditures of $80.1 million due primarily to the capital improvement projects discussed below and an increase in joint venture investments of $43.1 million related to contributions to the Dakota Prairie Refining, LLC ("Dakota Prairie") and Juniper (as defined below) joint ventures.

Financing Activities. Financing activities provided cash of $346.7 million in the nine months ended September 30, 2014 compared to $247.4 million during the prior year period. This increase is due primarily to net proceeds from the private placement of senior notes of $884.0 million in the 2014 period with no such proceeds in the 2013 period and increased revolving credit facility borrowings of $124.2 million. Partially offsetting these increases are the redemption of the remaining 2019 Notes of $500.0 million, a decrease in net proceeds from public offerings of common units (including our general partner's contributions) of $397.1 million and increased distributions to our unitholders of $8.6 million.

Acquisitions

Acquisitions impact our results of operations commencing on the closing date of each acquisition. Our acquisitions are discussed further in Note 4 of Part I, Item 1 "Financial Statements—Acquisitions" for additional information. Information regarding acquisitions completed during 2014 and 2013 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 our March 2014 private placement of 2021 Notes	Specialty Products
SOS	August 1, 2014	29.6	Borrowings under our revolving credit facility	Specialty Products
2014 Total		$263.6		
San Antonio	January 2, 2013	$117.9	Borrowings under our revolving credit facility and cash on hand	Fuel Products
Crude Oil Logistics	August 9, 2013	6.2	Cash on hand	Fuel Products
Bel-Ray	December 10, 2013	53.6	Net proceeds from our November 2013 private placement of 2022 Notes	Specialty Products
2013 Total		$177.7		

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. The refinery is expected to process 20,000 bpd of Bakken crude oil primarily to serve diesel demand in the region. Construction of the refinery began during the first quarter 2013 with startup of the refinery expected late in the fourth quarter of 2014. The refinery's total construction cost is estimated at approximately $365.0 million. The capitalization of the joint venture is expected to be funded through contributions of $182.5 million from MDU and a total of $182.5 million from us comprised of $107.5 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 be repaid by us through our allocation of profits from the joint venture. The term loan facility was funded in April 2013. The majority of the direct funding by us and MDU is expected to occur in 2014. As of September 30, 2014, we had contributed $76.3 million to the Dakota Prairie joint venture, funded primarily through cash flow from operations. The joint venture will allocate profits on a 50%/50% basis to us and MDU. We are covering the debt service cost of the lower interest rate term loan facility pursuant to the joint venture agreement. The joint venture is governed by a board of managers comprised of representatives from both us and MDU. MDU is to provide 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.

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

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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 GTL plant's total construction cost is estimated at approximately $135.0 million. The capitalization of the joint venture is expected to be funded through $100.0 million in contributions and $35.0 million in senior secured debt with the joint venture as the borrower. We intend to invest $25.0 million 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 September 30, 2014, we had an investment of $16.0 million 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.

The following table sets forth our capital improvement expenditures, replacement capital expenditures and environmental capital expenditures in each of the periods shown.

	Nine Months Ended September 30,	
	2014	2013
	(In millions)	
Capital improvement expenditures	$184.7	$65.6
Replacement capital expenditures	15.4	27.5
Environmental capital expenditures	8.2	21.0
Total	$208.3	$114.1

We anticipate that future capital expenditure requirements will be provided primarily through cash flow from operations, cash on hand and available borrowings under our revolving credit facility.

We estimate our replacement and environmental capital expenditures will be approximately $35.0 million to $45.0 million for 2014. These estimated amounts for 2014 include a portion of the $6.0 million to $8.0 million in environmental projects to be spent over the next year as required by our settlement with the LDEQ under the "Small Refinery and Single Site Refining Initiative." Please read Note 8 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 joint venture with MDU. Collectively, these projects are estimated to cost approximately $610 million. We estimate we will spend approximately $315 million to $345 million in 2014 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 20,000 bpd, including a new 20,000 bpd crude oil unit ("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.

Turnaround costs represent capitalized costs associated with our periodic major maintenance and repairs. During the nine months ended September 30, 2014, we spent approximately $22.6 million. Additionally, we estimate turnaround spending requirements will be approximately $25.0 million to $30.0 million for 2014. We expect these expenditures will be funded primarily through cash flow from operations.

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Debt and Credit Facilities

As of September 30, 2014, our primary debt and credit instruments consisted of:

- a $1,000.0 million senior secured revolving credit facility maturing in July 2019, subject to borrowing base limitations, with a maximum letter of credit sublimit equal to $600.0 million, which amount may be increased to 90% of revolver commitments in effect with the consent of the Agent (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”); and
- $350.0 million of 7.625% senior notes due 2022 (“2022 Notes”).

We believe we were in compliance with all covenants under the debt instruments in place as of September 30, 2014 and have adequate liquidity to conduct our business.

Short Term Liquidity

As of September 30, 2014, our principal sources of short-term liquidity were (i) $557.4 million of availability under our revolving credit facility and (ii) $7.7 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.

On July 14, 2014, we entered into a second amended and restated senior secured revolving credit facility, which increased the maximum availability of credit under the revolving credit facility from $850.0 million to $1,000.0 million, subject to borrowing base limitations, and includes a $500.0 million incremental uncommitted expansion option. 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, 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 September 30, 2014, we had availability on our revolving credit facility of $557.4 million, based on an $831.5 million borrowing base, $149.9 million in outstanding standby letters of credit and $124.2 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. 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 normal changes in working capital, payments of quarterly distributions to unitholders 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 September 30, 2014 were $237.0 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 September 30, 2014, availability for additional borrowings under our revolving credit facility was approximately $448.1 million at its lowest point. We believe that we will continue to have sufficient cash flow from operations and borrowing availability under our revolving credit facility to meet our financial commitments, minimum quarterly distributions to our unitholders, debt service obligations, debt instrument covenants, contingencies and anticipated capital expenditures.

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 September 30, 2014, 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.

As of September 30, 2014, we were in compliance with all covenants under the revolving credit facility.

For additional information regarding our revolving credit facility, see Note 9 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 cash from operations 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 September 30, 2014, we had $275.0 million in 2020 Notes, $900.0 million in 2021 Notes and $350.0 million in 2022 Notes outstanding. As of December 31, 2013, we had $500.0 million in 2019 Notes, $275.0 million in 2020 Notes and $350.0 million in 2022 Notes outstanding.

The indentures governing our senior notes contain covenants that, among other things, restrict our ability and the ability of certain of our subsidiaries to: (i) sell assets; (ii) pay distributions on, redeem or repurchase our common units or redeem or repurchase 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, except in the case of the 2020 Notes, an investment grade rating is required from both Moody’s and S&P. As of September 30, 2014, our Fixed Charge Coverage Ratio (as defined in the indentures governing the 2020, 2021 and 2022 Notes) was 2.4 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 9 — “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 2013 Annual Report.

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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 September 30, 2014. 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 increased by approximately $8.0 million subsequent to September 30, 2014 to a net asset of approximately $62.0 million. All credit support thresholds with our hedging counterparties are at levels such that it would take a substantial increase in fuel products crack spreads or interest rates to require significant additional collateral to be posted. As a result, we do not expect further increases in fuel products crack spreads or interest rates to significantly impact our liquidity.

Additionally, we have a collateral trust agreement (the "Collateral Trust Agreement") which governs how 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.

Equity Transactions

On March 10, 2014, we 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 and nine months ended September 30, 2014, we sold 134,955 common units for net proceeds of $3.7 million. Underwriting discounts totaled $0.1 million and our general partner contributed $0.1 million to retain its general partner interest.

During 2014, 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, 2013	January 24, 2014	February 4, 2014	February 14, 2014	$ 0.685	$ 52.6	$ 2.74	$ 210.4
March 31, 2014	April 22, 2014	May 5, 2014	May 15, 2014	$ 0.685	$ 52.5	$ 2.74	$ 210.0
June 30, 2014	July 24, 2014	August 4, 2014	August 14, 2014	$ 0.685	$ 52.5	$ 2.74	$ 210.0
September 30, 2014	October 21, 2014	November 4, 2014	November 14, 2014	$ 0.685	$ 52.6	$ 2.74	$ 210.4

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Contractual Obligations and Commercial Commitments

A summary of our total contractual cash obligations as of September 30, 2014 at current maturities and reflecting only those line items that have materially changed since December 31, 2013 is as follows:

		Payments Due by Period			
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
	(In millions)				
Operating activities:					
Interest on long-term debt at contractual rates and maturities (1)	$873.8	$130.5	$250.2	$248.3	$244.8
Operating lease obligations (2)	176.3	38.5	61.4	44.2	32.2
Letters of credit (3)	149.9	149.9	—	—	—
Purchase commitments (4)	735.2	728.1	6.8	0.3	—
Employment agreements	4.3	2.4	1.9	—	—
Financing activities:					
Capital lease obligations	43.8	0.6	1.4	1.6	40.2
Long-term debt obligations, excluding capital lease obligations	1,649.2	—	—	124.2	1,525.0
Total obligations	$3,632.5	$1,050.0	$321.7	$418.6	$1,842.2

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

(2) We have various operating leases primarily for railcars, the use of land, storage tanks, compressor stations, equipment, precious metals and office facilities that extend through May 2027.

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

(4) Purchase commitments consist primarily of obligations to purchase fixed volumes of crude oil, other feedstocks, 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 $65.9 million of feedstock for the LVT unit in each fiscal year of the term based on pricing estimates as of September 30, 2014. This amount is not included in the table above.

For additional information regarding our expected capital and turnaround expenditures for the remainder of 2014, for which we have not contractually committed, refer to “Capital Expenditures” above.

Off-Balance Sheet Arrangements

We did not enter into any material off-balance sheet debt or operating lease transactions during the three and nine months ended September 30, 2014.

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 2013 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 2013 Annual Report. There have been no material changes in that information other than as discussed below. Also, see Note 10 — “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) and natural gas. 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 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; 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”).

Subsequent to September 30, 2014, we entered into crude oil, diesel, jet fuel and gasoline swap contracts that offset derivative instruments existing at September 30, 2014 in order to lock in hedging gains for the near term as a result of favorable market conditions. The same volume of crude oil swaps were also executed to effectively lock in hedging gains. The net economic impact of this activity was to lock in implied crack spreads as follows:

Crude Oil and Diesel Swap Contracts by Expiration Dates	Barrels	BPD	Implied Crack Spread ($/Bbl)
Fourth Quarter 2014	1,242,000	13,500	$ 8.40
Calendar Year 2015	1,449,000	3,970	5.78
Totals	2,691,000		
Average price			$ 6.85

Crude Oil and Jet Swap Contracts by Expiration Dates	Barrels	BPD	Implied Crack Spread ($/Bbl)
Fourth Quarter 2014	183,000	1,989	$ 5.12
Calendar Year 2015	270,000	740	7.72
Totals	453,000		
Average price			$ 7.35

Crude Oil and Gasoline Swap Contracts by Expiration Dates	Barrels	BPD	Implied Crack Spread ($/Bbl)
Fourth Quarter 2014	488,000	5,304	$ 8.66
Totals	488,000		
Average price			$ 11.68

Excluding the above derivative instruments as of September 30, 2014, we had primarily entered into swap contracts on forecasted purchases from 2014 through 2016 of NYMEX WTI crude oil and forecasted sales of U.S. Gulf Coast ultra-low sulfur diesel, U.S. Gulf Coast jet fuel and U.S. Gulf Coast gasoline. These derivative instruments, on a combined basis, were entered into to hedge a portion of our gross profit in our fuel products segment. We have also entered into basis swap contracts that improve the effectiveness of our crude oil swap contracts by locking in the spread between NYMEX WTI and the crude oil that we are actually purchasing for use by our facilities. Please read Note 10 — “Derivatives” under Part I, Item 1 “Financial Statements—Notes to Unaudited Condensed Consolidated Financial

Statements” for additional information of the accounting treatment for the various types of derivative instruments and a further discussion of our hedging policies.

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The following table provides a summary of the implied crack spreads for our crude oil and diesel fuel swaps on a combined basis as of September 30, 2014 in our fuel products segment which we disclose in Note 10 — “Derivatives” under Part I, Item 1 “Financial Statements—Notes to Unaudited Condensed Consolidated Financial Statements.”

Crude Oil and Diesel Swap Contracts by Expiration Dates	Barrels	BPD	Implied Crack Spread ($/Bbl)
Fourth Quarter 2014	1,242,000	13,500	$27.47
Calendar Year 2015	5,785,500	15,851	26.59
Calendar Year 2016	2,196,000	6,000	27.23
Totals	9,223,500		
Average price			$26.86

The following table provides a summary of the implied crack spreads for our crude oil and jet fuel swaps on a combined basis as of September 30, 2014 in our fuel products segment which we disclose in Note 10 — “Derivatives” under Part I, Item 1 “Financial Statements—Notes to Unaudited Condensed Consolidated Financial Statements.”

Crude Oil and Jet Swap Contracts by Expiration Dates	Barrels	BPD	Implied Crack Spread ($/Bbl)
Fourth Quarter 2014	276,000	3,000	$24.30
Calendar Year 2015	957,500	2,623	28.10
Totals	1,233,500		
Average price			$27.25

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 September 30, 2014 in our fuel products segment which we disclose in Note 10 — “Derivatives” under Part I, Item 1 “Financial Statements—Notes to Unaudited Condensed Consolidated Financial Statements.”

Crude Oil and Gasoline Swap Contracts by Expiration Dates	Barrels	BPD	Implied Crack Spread ($/Bbl)
Fourth Quarter 2014	966,000	10,500	$10.81
Calendar Year 2015	1,091,000	2,989	16.50
Totals	2,057,000		
Average price			$13.83

The following table provides a summary of natural gas swaps as of September 30, 2014 in our specialty products segment which we disclose in Note 10 — “Derivatives” under Part I, Item 1 “Financial Statements—Notes to Unaudited Condensed Consolidated Financial Statements.”

Natural Gas Swap Contracts by Expiration Dates	MMBtu	$/MMBtu
Fourth Quarter 2014	1,210,000	$4.19
Calendar Year 2015	4,930,000	4.23
Calendar Year 2016	4,340,000	4.32
Calendar Year 2017	1,830,000	4.28
Totals	12,310,000	
Average price		$4.27

The following table provides a summary of natural gas collars as of September 30, 2014 in our specialty products segment which we disclose in Note 10 — “Derivatives” under Part I, Item 1 “Financial Statements—Notes to Unaudited Condensed Consolidated Financial Statements.”

Natural Gas Collars by Expiration Dates	MMBtu	Average Bought Call ($/MMBtu)	Average Sold Put ($/MMBtu)
Fourth Quarter 2014	160,000	$4.25	$3.79
Calendar Year 2015	920,000	4.25	3.80
Calendar Year 2016	600,000	4.25	3.89
Total	1,680,000		
Average price		$4.25	$3.83

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Our derivative instruments and overall specialty products segment and fuel products segment hedging positions are monitored regularly by our risk management committee, which includes our executive officers. The risk management committee reviews market information and our hedging positions regularly to determine if additional derivative 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.

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 September 30, 2014:

	In millions
Crude oil swaps	$12.5
Crude oil basis swaps	$0.5
Diesel swaps	$(9.2)
Jet fuel swaps	$(1.2)
Gasoline swaps	$(2.1)
Natural gas swaps	$12.3

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. On October 7, 2014, we received correspondence from the EPA evidencing the approval of a one-year extension of the small refinery exemption from the requirements of the RFS for our Shreveport and San Antonio refineries for the 2013 calendar year. 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 September 30, 2014 would be expected to have an impact on net income for 2014 of approximately $85 million to $90 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"). We have disclosed this interest rate swap designated as a fair value hedge in Note 10 — "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 September 30, 2014 and December 31, 2013, which we disclose in Note 9 — "Long-Term Debt" and Note 11— " Fair Value Measurements" under Part I, Item 1 "Financial Statements—Notes to Unaudited Condensed Consolidated Financial Statements."

	September 30, 2014		December 31, 2013	
	Fair Value	Carrying Value	Fair Value	Carrying Value
	(In millions)			
Financial Instrument:				
2019 Notes	$—	$—	$554.2	$490.5
2020 Notes	$304.2	$271.2	$309.4	$270.7

2021 Notes	$864.0	$900.0	$—	$—
2022 Notes	$356.1	$344.5	$353.9	$344.8

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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 $1,000.0 million revolving credit facility as of September 30, 2014, 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 $124.2 million of variable rate debt as of September 30, 2014. Holding other variables constant (such as debt levels), a 100 basis point change in interest rates on our variable rate debt as of September 30, 2014 would be expected to have an impact on net income and cash flows for 2014 of approximately $1.2 million. We had no variable rate debt outstanding as of December 31, 2013.

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 September 30, 2014 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 third quarter of 2014 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

On December 10, 2013, March 31, 2014 and August 1, 2014, we completed the Bel-Ray, 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 the Bel-Ray, Anchor and SOS Acquisitions’ historical internal controls over financial reporting with ours. We expect to complete the integration of the Bel-Ray Acquisition in fiscal year 2014 and the integrations 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 8 — "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 discussed below, you should carefully consider the risk factors discussed in Part I, Item 1A "Risk Factors" in our 2013 Annual Report or in Part II, Item 1A "Risk Factors" in our Q1 Quarterly Report, which could materially affect our business, financial condition or future results. 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 2013 Annual Report or Part II, Item 1A "Risk Factors" in our Q1 Quarterly Report.

Proposed rule imposing more stringent standards relating to the use of upgraded emissions controls, observance of performance requirements and fenceline monitoring could cause us to incur increased capital expenditures and operating costs, which could be significant.

On May 15, 2014, the EPA issued a proposed rule that would further control air emissions from refineries. In particular, this rulemaking proposes amendments to two refinery standards already in effect: the National Emission Standards for Hazardous Air Pollutants ("NESHAP") from Petroleum Refineries and the NESHAP for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units. In addition, the proposed rule would amend emission requirements under a third refinery standard already in effect, the Petroleum Refinery New Source Performance Standard. Collectively, the amendments recommended in the proposed rule would, among other things, require monitoring of air concentrations of benzene around the fenceline perimeter of refineries to assure that emissions are controlled and these results would be available to the public. The proposal would also require upgraded emission controls for storage tanks including controls for smaller tanks; performance requirements for flares to ensure that waste gases are properly destroyed; and emissions standards for delayed coking units which are currently a significant unregulated source of toxic air emissions at refineries. The rule is currently in a proposed form but, if adopted, could increase our compliance costs, which could be significant.

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
July 1, 2014 - July 31, 2014	—	$—	—	—
August 1, 2014 - August 31, 2014 (1)	732	30.54	—	—
September 1, 2014 - September 30, 2014	—	—	—	—
Total	732	$30.54	—	—

(1) A total of 732 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 $30.54 for total consideration of approximately $0.1 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 2013 Annual Report.

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Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

None.

Item 5. Other Information

None.

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Item 6. Exhibits

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

Exhibit Number	Description
3.1	Certificate of Limited Partnership of Calumet Specialty Products Partners, L.P. (incorporated by reference to Exhibit 3.1 to the Registrant's Registration Statement on Form S-1 filed with the Commission on October 7, 2005 (File No. 333-128880)).
3.2	Amended and Restated Limited Partnership Agreement of Calumet Specialty Products Partners, L.P. (incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the Commission on February 13, 2006 (File No. 000-51734)).
3.3	Amendment No. 1 to the First Amended and Restated Agreement of Limited Partnership of Calumet Specialty Products Partners, L.P. (incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the Commission on July 11, 2006 (File No. 000-51734)).
3.4	Amendment No. 2 to First Amended and Restated Agreement of Limited Partnership of Calumet Specialty Products Partners, L.P. (incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the Commission on April 18, 2008 (File No. 000-51734)).
3.5	Certificate of Formation of Calumet GP, LLC (incorporated by reference to Exhibit 3.3 of Registrant's Registration Statement on Form S-1 filed with the Commission on October 7, 2005 (File No. 333-128880)).
3.6	Amended and Restated Limited Liability Company Agreement of Calumet GP, LLC (incorporated by reference to Exhibit 3.2 to the Registrant's Current Report on Form 8-K filed with the Commission on February 13, 2006 (File No. 000-51734)).
10.1	Second Amended and Restated Credit Agreement, dated as of July 14, 2014, by and among Calumet Specialty Products Partners, L.P. and certain of its subsidiaries as Borrowers, certain of its subsidiaries as Guarantors, the Lenders, Bank of America, N.A., as Agent, JPMorgan Chase Bank, N.A. and Wells Fargo Capital Finance, LLC, as Co-Syndication Agents, U.S. Bank National Association and Deutsche Bank Trust Company Americas, as Co-Documentation Agents and Bank of America, N.A., J.P. Morgan Securities LLC and Wells Fargo Capital Finance, LLC, as Joint Lead Arrangers and Joint Book Runners (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed with the Commission on July 17, 2014 (File No. 000-51734)).
31.1*	Sarbanes-Oxley Section 302 certification of F. William Grube.
31.2*	Sarbanes-Oxley Section 302 certification of R. Patrick Murray, II.
32.1**	Section 1350 certification of F. William Grube 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: November 7, 2014	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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