Calumet Specialty Products Partners, L.P.
Form 10-Q
May 10, 2013
Table of Contents

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

Form 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED MARCH 31, 2013
OR
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM TO
Commission File Number: 000-51734

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

Delaware (State or Other Jurisdiction of Incorporation or Organization)	37-1516132 (I.R.S. Employer Identification Number)
2780 Waterfront Parkway East Drive, Suite 200 Indianapolis, Indiana (Address of Principal Executive Officers)	46214 (Zip Code)

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

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

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

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

At May 10, 2013, there were 69,317,278 common units outstanding.

Table of Contents

CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
QUARTERLY REPORT
For the Three Months Ended March 31, 2013
Table of Contents

	Page
Part I	
Item 1. Financial Statements	
Condensed Consolidated Balance Sheets	4
Unaudited Condensed Consolidated Statements of Operations	5
Unaudited Condensed Consolidated Statements of Comprehensive Income (Loss)	6
Unaudited Condensed Consolidated Statements of Partners' Capital	7
Unaudited Condensed Consolidated Statements of Cash Flows	8
Notes to Unaudited Condensed Consolidated Financial Statements	10
Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations	40
Item 3. Quantitative and Qualitative Disclosures About Market Risk	59
Item 4. Controls and Procedures	61
Part II	
Item 1. Legal Proceedings	62
Item 1A. Risk Factors	62
Item 2. Unregistered Sales of Equity Securities and Use of Proceeds	63
Item 3. Defaults Upon Senior Securities	63
Item 4. Mine Safety Disclosures	63
Item 5. Other Information	63
Item 6. Exhibits	64

Table of Contents

FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q (this “Quarterly Report”) includes certain “forward-looking statements.” These statements can be identified by the use of forward-looking terminology including “may,” “intend,” “believe,” “expect,” “anticipate,” “estimate,” “continue,” or other similar words. The statements regarding (i) estimated capital expenditures as a result of required audits or required operational changes or other environmental and regulatory liabilities, (ii) our anticipated levels of, use and effectiveness of derivatives to mitigate our exposure to crude oil price changes and fuel products price changes and (iii) 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 (1) Part I, Item 3 “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, 2012 (“2012 Annual Report”) and (2) Part II, Item 1A “Risk Factors” in this Quarterly Report. Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly update or revise any forward-looking statements after the date they are made, whether as a result of new information, future events or otherwise.

References in this Quarterly Report to “Calumet Specialty Products Partners, L.P.,” “the Company,” “we,” “our,” “us” 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.

Table of Contents

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

	March 31, 2013	December 31, 2012
	(Unaudited)	
	(In millions, except unit data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$10.5	$32.2
Accounts receivable:		
Trade	305.8	219.3
Other	6.6	7.5
	312.4	226.8
Inventories	622.0	553.6
Derivative assets	1.0	3.1
Prepaid expenses and other current assets	17.5	10.3
Deposits	2.4	7.9
Total current assets	965.8	833.9
Property, plant and equipment, net	1,084.5	986.9
Investment in unconsolidated affiliate	11.1	1.9
Goodwill	190.9	187.0
Other intangible assets, net	190.7	197.1
Other noncurrent assets, net	56.9	46.2
Total assets	$2,499.9	$2,253.0
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$415.4	$333.4
Accrued interest payable	28.8	23.5
Accrued salaries, wages and benefits	17.8	20.1
Accrued income taxes payable	—	27.6
Other taxes payable	13.0	13.7
Other current liabilities	21.0	8.3
Current portion of long-term debt	0.7	0.8
Derivative liabilities	25.8	48.0
Total current liabilities	522.5	475.4
Pension and postretirement benefit obligations	23.1	24.0
Other long-term liabilities	1.1	1.1
Long-term debt, less current portion	892.3	862.7
Total liabilities	1,439.0	1,363.2
Commitments and contingencies		
Partners' capital:		
Limited partners' interest (63,279,778 and 57,529,778 units issued and outstanding at March 31, 2013 and December 31, 2012, respectively)	1,056.4	884.8
General partner's interest	35.1	30.5
Accumulated other comprehensive loss	(30.6)	(25.5)

Total partners' capital	1,060.9	889.8
Total liabilities and partners' capital	$2,499.9	$2,253.0

See accompanying notes to unaudited condensed consolidated financial statements.

Table of Contents

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

	For the Three Months Ended March 31,	
	2013	2012
	(In millions, except per unit and unit data)	
Sales	$1,318.6	$1,169.6
Cost of sales	1,184.2	1,085.4
Gross profit	134.4	84.2
Operating costs and expenses:		
Selling	15.9	4.5
General and administrative	25.1	13.7
Transportation	35.4	27.5
Taxes other than income taxes	3.0	1.7
Other	0.6	1.8
Operating income	54.4	35.0
Other income (expense):		
Interest expense	(24.8)	(18.6)
Realized gain (loss) on derivative instruments	(8.6)	9.4
Unrealized gain on derivative instruments	24.5	26.0
Other	0.7	0.2
Total other income (expense)	(8.2)	17.0
Net income before income taxes	46.2	52.0
Income tax expense	0.2	0.1
Net income	$46.0	$51.9
Allocation of net income:		
Net income	$46.0	$51.9
Less:		
General partner’s interest in net income	0.9	1.0
General partner’s incentive distribution rights	3.2	0.5
Non-vested share based payments	0.2	0.3
Net income available to limited partners	$41.7	$50.1
Weighted average limited partner units outstanding:		
Basic	62,831,155	51,684,741
Diluted	63,017,869	51,736,396
Limited partners’ interest basic net income per unit	$0.67	$0.97
Limited partners’ interest diluted net income per unit	$0.66	$0.97
Cash distributions declared per limited partner unit	$0.65	$0.53

See accompanying notes to unaudited condensed consolidated financial statements.

Table of Contents

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

	For the Three Months Ended March 31,	
	2013	2012
	(In millions)	
Net income	$46.0	$51.9
Other comprehensive income (loss):		
Cash flow hedges:		
Cash flow hedge loss reclassified to net income	11.6	42.8
Change in fair value of cash flow hedges	(17.3)	(173.0)
Defined benefit pension and retiree health benefit plans	0.6	0.2
Total other comprehensive loss	(5.1)	(130.0)
Comprehensive income (loss) attributable to partners' capital	$40.9	$(78.1)

See accompanying notes to unaudited condensed consolidated financial statements.

Table of Contents

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

	Accumulated Other Comprehensive Loss	Partners' Capital		
		General Partner	Limited Partners	Total
	(In millions)			
Balance at December 31, 2012	$(25.5)	$30.5	$884.8	$889.8
Other comprehensive loss	(5.1)	—	—	(5.1)
Net income	—	4.1	41.9	46.0
Units repurchased for phantom unit grants	—	—	(5.0)	(5.0)
Amortization of vested phantom units	—	—	0.8	0.8
Issuances of phantom units, net of repurchases for taxes	—	—	(0.3)	(0.3)
Proceeds from public offering of common units, net	—	—	175.5	175.5
Contributions from Calumet GP, LLC	—	3.7	—	3.7
Distributions to partners	—	(3.2)	(41.3)	(44.5)
Balance at March 31, 2013	$(30.6)	$35.1	$1,056.4	$1,060.9

See accompanying notes to unaudited condensed consolidated financial statements.

7

Table of Contents

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

	For the Three Months Ended March 31,	
	2013	2012
	(In millions)	
Operating activities		
Net income	$46.0	$51.9
Adjustments to reconcile net income to net cash provided by (used in) operating activities:		
Depreciation and amortization	29.3	19.6
Amortization of turnaround costs	2.6	3.5
Non-cash interest expense	1.7	1.4
Provision for doubtful accounts	0.3	0.3
Unrealized gain on derivative instruments	(24.5)	(26.0)
Non-cash equity based compensation	2.9	0.6
Other non-cash activities	0.6	0.3
Changes in assets and liabilities:		
Accounts receivable	(85.9)	(75.3)
Inventories	(51.4)	1.8
Prepaid expenses and other current assets	(7.1)	2.2
Derivative activity	(1.3)	1.4
Turnaround costs	(13.9)	(7.9)
Deposits	5.4	(1.2)
Accounts payable	82.6	36.0
Accrued interest payable	5.3	13.8
Accrued salaries, wages and benefits	(2.7)	(3.9)
Accrued income taxes payable	(27.6)	—
Other taxes payable	(0.7)	(0.3)
Other liabilities	5.3	(1.0)
Pension and postretirement benefit obligations	(0.7)	(0.3)
Net cash provided by (used in) operating activities	(33.8)	16.9
Investing activities		
Additions to property, plant and equipment	(21.1)	(9.7)
Cash paid for acquisitions, net of cash acquired	(117.7)	(46.4)
Investment in unconsolidated affiliate	(9.2)	—
Proceeds from sale of property, plant and equipment	—	1.9
Net cash used in investing activities	(148.0)	(54.2)
Financing activities		
Proceeds from borrowings — revolving credit facility	607.8	678.6
Repayments of borrowings — revolving credit facility	(578.6)	(604.4)
Payments on capital lease obligations	(0.2)	(0.4)
Proceeds from other financing obligations	3.5	—
Proceeds from public offering of common units, net	175.5	—
Contributions from Calumet GP, LLC	3.7	—
Units repurchased and taxes paid for phantom unit grants	(7.1)	(2.0)
Distributions to partners	(44.5)	(28.2)
Net cash provided by financing activities	160.1	43.6

8

Table of Contents

Net increase (decrease) in cash and cash equivalents	(21.7)	6.3
Cash and cash equivalents at beginning of period	32.2	0.1
Cash and cash equivalents at end of period	$10.5	$6.4
Supplemental disclosure of noncash financing and investing activities		
Equipment acquired under capital lease	$—	$5.8

See accompanying notes to unaudited condensed consolidated financial statements.

Table of Contents

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 Delaware limited partnership. The general partner of the Company is Calumet GP, LLC, a Delaware limited liability company. As of March 31, 2013, the Company had 63,279,778 limited partner common units and 1,291,424 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, asphalt and fuel and fuel related products including gasoline, diesel, jet fuel and heavy fuel oils. The Company is also engaged in the resale of purchased crude oil to third party customers. The Company owns facilities located in Shreveport, Louisiana ("Shreveport" and "TruSouth"); Superior, Wisconsin ("Superior"); San Antonio, Texas ("San Antonio"); Great Falls, Montana ("Montana"); Princeton, Louisiana ("Princeton"); Cotton Valley, Louisiana ("Cotton Valley"); Karns City, Pennsylvania ("Karns City"); Dickinson, Texas ("Dickinson"); Louisiana, Missouri ("Missouri") and Porter, Texas ("Royal Purple") and terminals located in Burnham, Illinois ("Burnham"); Rhinelander, Wisconsin ("Rhinelander"); Crookston, Minnesota ("Crookston") and Proctor, Minnesota ("Duluth").

The unaudited condensed consolidated financial statements of the Company as of March 31, 2013 and for the three months ended March 31, 2013 and 2012 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 United States of America (the "U.S.") have been condensed or omitted pursuant to such rules and regulations, although the Company believes that the following disclosures are adequate to make the information presented not misleading. These unaudited condensed consolidated financial statements reflect all adjustments that, in the opinion of management, are necessary to present fairly the results of operations for the interim periods presented. All adjustments are of a normal nature, unless otherwise disclosed. The results of operations for the three months ended March 31, 2013 are not necessarily indicative of the results that may be expected for the year ending December 31, 2013. These unaudited condensed consolidated financial statements should be read in conjunction with the Company's 2012 Annual Report.

2. New and Recently Adopted Accounting Pronouncements

In December 2011, the Financial Accounting Standards Board ("FASB") issued ASU No. 2011-11, Balance Sheet (Topic 210) — Disclosures about Offsetting Assets and Liabilities ("ASU 2011-11"). ASU 2011-11 requires entities to disclose information about offsetting and related arrangements to enable financial statement users to understand the effect of such arrangements on the balance sheet. Entities are required to disclose both gross information and net information about financial instruments and derivative instruments that are either offset in the balance sheet or subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset. In January 2013, the FASB issued ASU No. 2013-01, Balance Sheet Topic (210) — Clarifying the Scope of Disclosures About Offsetting Assets and Liabilities ("ASU 2013-01"), which clarifies the scope of the offsetting disclosures and addresses any unintended consequences. Amendments to ASU 2011-11, as superseded by ASU 2013-01, are effective for the first reporting period (including interim periods) beginning on or after January 1, 2013 and should be applied retrospectively for any period presented. The adoption of ASU 2013-01 and ASU 2011-11 concerns presentation and disclosure only.

In October 2012, the FASB issued ASU No. 2012-04, Technical Corrections and Improvements ("ASU 2012-04"). ASU 2012-04 covers a wide range of topics in the Accounting Standards Codification. These amendments include technical corrections and improvements to the Accounting Standards Codification and conforming amendments related to fair value measurements. ASU 2012-04 is effective for fiscal periods beginning after December 15, 2012. The adoption of ASU 2012-04 did not have an impact on the Company's consolidated financial statements.

In February 2013, the FASB issued ASU No. 2013-02, Comprehensive Income (Topic 220) — Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income ("ASU 2013-02"). ASU 2013-02 requires entities to report either on the statement of operations or disclose in the footnotes to the consolidated financial statements the effects on earnings from items that are reclassified out of comprehensive income. For amounts that are not required to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures that provide additional details about those amounts. ASU 2013-02 is effective prospectively for the first reporting period after December 15, 2012 with early adoption permitted. The adoption of ASU 2013-02 concerns presentation and disclosure only.

Table of Contents

In February 2013, the 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 Company is currently evaluating the impacts of the adoption of ASU 2013-04 on its consolidated financial statements.

3. Acquisitions

Missouri Acquisition

On January 3, 2012, the Company completed the acquisition of the aviation and refrigerant lubricants business (a polyolester based synthetic lubricants business) of Hercules Incorporated, a subsidiary of Ashland, Inc., including a manufacturing facility located in Louisiana, Missouri for aggregate consideration of approximately $19.6 million ("Missouri Acquisition"). The Missouri Acquisition was financed with borrowings under the Company's revolving credit facility and cash on hand. The Company believes the Missouri Acquisition provides greater diversity to its specialty products segment. The assets acquired and results of operations have been included in the Company's condensed consolidated balance sheets and the Company's unaudited condensed consolidated statements of operations since the date of acquisition. In connection with the Missouri Acquisition, during the three months ended March 31, 2012, the Company incurred acquisition costs of approximately $0.5 million, which are reflected in general and administrative expenses in the unaudited condensed consolidated statements of operations.

The Company recorded $1.5 million of goodwill as a result of the Missouri Acquisition, all of which was recorded within the Company's specialty products segment. Goodwill recognized in the acquisition relates primarily to enhancing the Company's strategic platform for expansion in its specialty products segment. The allocation of the aggregate purchase price to assets acquired is as follows (in millions):

	Allocation of Purchase Price
Inventories	$2.7
Property, plant and equipment	10.0
Goodwill	1.5
Other intangible assets	5.4
Total purchase price	$19.6

The component of the intangible asset listed in the table above as of January 3, 2012, based upon a third party appraisal, was as follows (in millions):

	Amount	Life (Years)
Customer relationships	$5.4	20

TruSouth Acquisition

On January 6, 2012, the Company completed the acquisition of all of the outstanding membership interests of TruSouth Oil, LLC ("TruSouth"), a specialty petroleum packaging and distribution company located in Shreveport, Louisiana for aggregate consideration of approximately $26.9 million, net of cash acquired ("TruSouth Acquisition"). The TruSouth Acquisition was financed with borrowings under the Company's revolving credit facility. Immediately prior to its acquisition by the Company, TruSouth was owned in part by affiliates of the Company's general partner. The Company believes the TruSouth Acquisition provides greater diversity to its specialty products segment. The assets acquired and liabilities assumed have been included in the Company's condensed consolidated balance sheets and results of operations have been included in the Company's unaudited condensed consolidated statements of operations since the date of acquisition. In connection with the TruSouth Acquisition, during the three months ended March 31, 2012, the Company incurred acquisition costs of $0.2 million, which are reflected in general and administrative expenses in the unaudited condensed consolidated statements of operations.

The Company recorded $0.4 million of goodwill as a result of the TruSouth Acquisition, all of which was recorded within the Company’s specialty products segment. Goodwill recognized in the acquisition relates primarily to enhancing the

Table of Contents

Company's strategic platform for expansion in its specialty products segment. The allocation of the aggregate purchase price to assets acquired and liabilities assumed is as follows (in millions):

	Allocation of Purchase Price
Accounts receivable	$5.2
Inventories	8.0
Prepaid expenses and other current assets	0.3
Property, plant and equipment	17.7
Goodwill	0.4
Other intangible assets	2.6
Accounts payable	(2.7)
Accrued salaries, wages and benefits	(0.2)
Other current liabilities	(0.9)
Long-term debt	(3.5)
Total purchase price, net of cash acquired	$26.9

The components of intangible assets listed in the table above as of January 6, 2012, based upon a third party appraisal, were as follows (in millions):

	Amount	Life (Years)
Customer relationships	$1.8	16
Tradenames	0.7	9
Non-competition agreements	0.1	2
Total	$2.6	
Weighted average amortization period		14

Royal Purple Acquisition

On July 3, 2012, the Company completed the acquisition of Royal Purple, Inc. ("Royal Purple"), a Texas corporation which was converted into a Delaware limited liability company at closing, for aggregate consideration of approximately $331.2 million, net of cash acquired ("Royal Purple Acquisition"). Royal Purple is a leading independent formulator and marketer of premium industrial and consumer lubricants to a diverse customer base across several large markets including oil and gas, chemicals and refining, power generation, manufacturing and transportation, food and drug manufacturing and automotive aftermarket. The Royal Purple Acquisition was financed with net proceeds of $262.6 million from the Company's June 2012 private placement of 9 5/8% senior notes due August 1, 2020 and cash on hand. The Company believes the Royal Purple Acquisition increases its position in the specialty lubricants market, expands its geographic reach, increases its asset diversity and enhances its specialty products segment. The assets acquired and liabilities assumed have been included in the Company's condensed consolidated balance sheets and results of operations have been included in the Company's unaudited condensed consolidated statements of operations since the date of acquisition.

The Company recorded $109.2 million of goodwill as a result of the Royal Purple Acquisition, all of which was recorded within the Company's specialty products segment. Goodwill recognized in the acquisition relates primarily to enhancing the Company's strategic platform for expansion in its specialty products segment.

The allocation of the aggregate purchase price to assets acquired and liabilities assumed is as follows (in millions):

	Allocation of Purchase Price
Accounts receivable	$15.2
Inventories	19.3
Prepaid expenses and other current assets	0.2
Property, plant and equipment	10.6
Goodwill	109.2
Other intangible assets	183.4
Accounts payable	(3.8)
Accrued salaries, wages and benefits	(1.7)
Taxes payable	(0.2)
Other current liabilities	(1.0)
Total purchase price, net of cash acquired	$331.2

The components of intangible assets listed in the table above as of July 3, 2012, based upon a third party appraisal, were as follows (in millions):

	Amount	Life (Years)
Customer relationships	$118.7	20
Tradenames	14.8	Indefinite
Tradenames	5.7	10
Trade secrets	44.2	12
Total	$183.4	
Weighted average amortization period		18

Montana Acquisition

On October 1, 2012, the Company completed the acquisition from Connacher Oil and Gas Limited ("Connacher") of all the shares of common stock of Montana Refining Company, Inc. ("Montana") and an insignificant affiliated company for aggregate consideration of approximately $191.6 million, net of cash acquired and excluding certain purchase price adjustments ("Montana Acquisition"). Montana produces gasoline, diesel, jet fuel and asphalt, which are marketed primarily into local markets in Washington, Montana, Idaho and Alberta, Canada. The Montana Acquisition was funded primarily with cash on hand with the balance through borrowings under the Company's revolving credit facility. The Company believes the Montana Acquisition further diversifies its crude oil feedstock slate, operating asset base and geographic presence. The assets acquired and liabilities assumed and results of operations have been included in the Company's condensed consolidated balance sheets and unaudited condensed consolidated statements of operations since the date of acquisition. In connection with the Montana Acquisition, during the three months ended March 31, 2013, the Company incurred acquisition costs of approximately $0.1 million, which are reflected in general and administrative expenses in the unaudited condensed consolidated statements of operations.

Immediately after closing the Montana Acquisition, the Company converted Montana Refining Company, Inc. into a Delaware limited liability company, Calumet Montana Refining, LLC. This conversion resulted in the recognition of a current income tax liability of approximately $27.6 million, which was paid during the three months ended March 31, 2013, and was offset by the derecognition of a deferred tax liability for a comparable amount assumed in connection with the acquisition.

The Company recorded $27.6 million of goodwill as a result of the Montana Acquisition, all of which was recorded within the Company's fuel products segment. Goodwill recognized in the acquisition relates primarily to enhancing the Company's strategic platform for expansion in its fuel products segment.

The preliminary allocation of the aggregate purchase price to assets acquired and liabilities assumed is as follows (in millions):

Table of Contents

	Allocation of Purchase Price
Accounts receivable	$29.0
Inventories	43.7
Prepaid expenses and other current assets	23.1
Deposits	0.3
Property, plant and equipment	125.9
Goodwill	27.6
Other noncurrent assets, net	0.3
Accounts payable	(8.4)
Accrued salaries, wages and benefits	(1.4)
Deferred income tax liability	(27.6)
Accrued income taxes payable	(15.6)
Other taxes payable	(3.0)
Other current liabilities	(0.1)
Pension and postretirement benefit obligations	(2.2)
Total purchase price, net of cash acquired	$191.6

San Antonio Acquisition

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 $117.7 million, net of cash acquired and excluding certain purchase price adjustments. The refinery has total crude oil throughput capacity of 14,500 bpd and primarily produces jet fuel, diesel, 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 geographical presence. The assets acquired and results of operations have been included in the Company's condensed consolidated balance sheets and unaudited condensed consolidated statements of operations since the date of acquisition. In connection with the San Antonio Acquisition, during the three months ended March 31, 2013, the Company incurred acquisition costs of approximately $0.4 million, which are reflected in general and administrative expenses in the unaudited condensed consolidated statements of operations.

The Company recorded $3.9 million of goodwill as a result of the San Antonio Acquisition, all of which was recorded within the Company's fuel products segment. Goodwill recognized in the acquisition relates primarily to enhancing the Company's strategic platform for expansion in its fuel products segment.

The San Antonio Acquisition purchase price allocation has not yet been finalized due to the timing of the closing of the acquisition. The final determination of fair value for certain assets and liabilities will be completed as soon as the information necessary to complete the analysis is obtained. The preliminary allocation of the aggregate purchase price to assets acquired and liabilities assumed is as follows (in millions):

	Allocation of Purchase Price
Inventories	$17.0
Property, plant and equipment, net	100.7
Goodwill	3.9
Accrued salaries, wages and benefits	(0.1)
Other current liabilities	(3.8)
Total purchase price, net of cash acquired	$117.7

Table of Contents

Results of Sales and Earnings

The following financial information reflects sales and operating income of the Missouri, TruSouth, Royal Purple, Montana and San Antonio Acquisitions that are included in the unaudited condensed consolidated statements of operations for the three months ended March 31, 2013 and sales and operating income of the Missouri and TruSouth Acquisitions that are included in the unaudited condensed consolidated statements of operations for the three months ended March 31, 2012 (in millions):

	Three Months Ended March 31,	
	2013	2012
Sales	$287.7	$26.2
Operating income	$8.9	$0.2

Pro Forma Financial Information (Unaudited)

The following unaudited pro forma financial information reflects the unaudited condensed consolidated results of operations of the Company as if the Royal Purple, Montana and San Antonio Acquisitions had taken place on January 1, 2012 (in millions except for per unit data).

	Three Months Ended March 31,	
	2013	2012
Sales	$1,318.6	$1,411.6
Net income	46.0	$43.6
Limited partners' interest net income per unit — basic and diluted	$0.60	$0.60

The Company's historical financial information was adjusted to give effect to the pro forma events that were directly attributable to the Royal Purple, Montana and San Antonio Acquisitions. 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.

Fair Value Measurements of Acquisitions

The fair value of the property, plant and equipment and intangible assets are based upon the discounted cash flow method that involves inputs that are not observable in the market (Level 3). Goodwill assigned represents the amount of consideration transferred in excess of the fair value assigned to individual assets acquired and liabilities assumed.

4. Inventories

The cost of inventory is recorded using the last-in, first-out (LIFO) method. An actual valuation of inventory under the LIFO method can be made only at the end of each year based on the inventory levels and costs at that time. Accordingly, interim LIFO calculations are based on management's estimates of expected year-end inventory levels and costs and are subject to the final year-end LIFO inventory valuation. Costs include crude oil and other feedstocks, labor, processing costs and refining overhead costs. Inventories are valued at the lower of cost or market value. The replacement cost of these inventories, based on current market values, would have been $42.1 million and $38.3 million higher as of March 31, 2013 and December 31, 2012, respectively.

Inventories consist of the following (in millions):

	March 31, 2013	December 31, 2012
Raw materials	$139.4	$85.4
Work in process	113.8	119.5
Finished goods	368.8	348.7
	$622.0	$553.6

15

Table of Contents

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

In addition, the use of the LIFO inventory method may result in increases or decreases to cost of sales in years that inventory volumes decline as the result of charging cost of sales with LIFO inventory costs generated in prior periods. In periods of rapidly declining prices, LIFO inventories may have to be written down to market value due to the higher costs assigned to LIFO layers in prior periods. During the three months ended March 31, 2013 and 2012 the Company recorded $5.4 million and $0.4 million of losses in cost of sales in the unaudited condensed consolidated statements of operations due to the lower of cost or market valuation.

5. Joint Venture

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. The refinery’s total construction cost is estimated at approximately $300.0 million. The capitalization of the joint venture is expected to be funded through contributions of $150.0 million from MDU and $75.0 million from the Company and proceeds of $75.0 million from an unsecured syndicated term loan facility with the joint venture as the borrower. The term loan facility was funded in April 2013. Funding for the project will occur over the course of the construction period, with the majority of the direct funding by the Company expected to occur in 2014. The diesel refinery is expected to be operational in the fourth quarter of 2014. The joint venture will allocate profits on a 50%/50% basis to the Company and MDU. The joint venture will be 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 will provide refinery operations, crude oil procurement and refined product marketing expertise to the joint venture.

The Company accounts for its ownership in its joint venture under the equity method of accounting. The Company is using the equity method of accounting for this joint venture. As of March 31, 2013, the Company contributed $11.1 million to Dakota Prairie Refining, LLC to fund development of the refinery.

6. Commitments and Contingencies

From time to time, the Company is a party to certain claims and litigation incidental to its business, including claims made by various taxation and regulatory authorities, such as the U.S. Environmental Protection Agency (“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 and terminal operations, which are subject to stringent and complex 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. The

Company is currently evaluating the effect that the NSPS rule may have on its refinery operations.

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

San Antonio Refinery

In connection with the San Antonio Acquisition, the Company agreed to indemnify NuStar 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”), another 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 contamination at the San Antonio refinery. The Company is not a party to this Agreed Order. The Company is in discussions with both TCEQ and Anadarko over how best to address pre-existing contamination at the San Antonio refinery.

Montana Refinery

In connection with the Montana Acquisition (see Note 3), 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 that all damages related to such contamination at the Montana refinery are covered by a contractual indemnity provided by Holly 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. for all environmental conditions arising under Holly’s ownership and operation of the Montana refinery. As a result of the Montana Acquisition, the Company is indemnified by Holly as a direct beneficiary under the asset purchase agreement between Holly and Connacher. Prior to the Montana Acquisition, Holly had reimbursed Connacher in accordance with the contractual indemnity for remedial actions related to such contamination at the Montana refinery.

Superior Refinery

In connection with the Superior Acquisition, the Company became a party to an existing 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 will have to complete certain reductions in air emissions at the Superior refinery as well as report upon certain emissions from the facility to the EPA and the WDNR. The Company currently estimates costs of approximately $3.0 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 significant. In addition, the Company may have to pursue certain additional environmental and safety-related projects at the Superior refinery including, but not limited to: (i) installing process equipment pursuant to applicable EPA fuel content regulations; (ii) purchasing emission credits on an interim basis until such time as any process equipment that may be required under the EPA fuel content regulations is installed and operational; (iii) performing monitoring of historical contamination at the facility; (iv) upgrading treatment equipment or possibly pursuing other remedies, as necessary, to satisfy new effluent discharge limits under a federal Clean Water Act permit renewal that is pending and (v) pursuing various voluntary programs at the Superior refinery, including removing asbestos-containing materials or enhancing process safety or other maintenance practices. Completion of these additional projects will result in the Company incurring additional costs, which could be substantial. For the three months ended March 31, 2013 and 2012, the Company incurred approximately $0.1 million and $0.5 million, respectively, of costs 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. 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 operations 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

Table of Contents

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 discharged by Murphy Oil. The contractual indemnity by Murphy Oil for such specified environmental liabilities is believed by the Company to be unlimited in duration and not subject to any monetary deductibles or maximums. The Company is also contractually indemnified by Murphy Oil under the asset purchase agreement until October 1, 2013 for liabilities arising from breaches of certain environmental representations and warranties made by Murphy Oil, subject to a maximum liability of $22.0 million, for which the Company is required to contribute up to the first $6.6 million. The amount of any damages payable by Murphy Oil pursuant to the contractual indemnities under the asset purchase agreement will be net of any amount recoverable under an environmental insurance policy that the Company has obtained in connection with the Superior Acquisition, which names 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 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 March 31, 2013 and 2012, the Company incurred approximately $2.2 million and $1.0 million, respectively, of expenditures and estimates additional expenditures of approximately $1.0 million to $4.0 million of capital expenditures and expenditures related to additional personnel and environmental studies over the next three years as a result of the implementation of those requirements. These capital investment requirements are incorporated into the Company's annual capital expenditures budgets 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.

In August 2011, the EPA conducted an inspection of the Shreveport refinery's Risk Management Program compliance. An inspection report dated October 20, 2011 was transmitted to the Shreveport refinery. The Company submitted supplemental information to the EPA, which was followed by a site visit from EPA personnel. On February 25, 2013, the EPA issued a draft Consent Agreement and Final Order to the Shreveport refinery, which included a proposed civil penalty of $0.8 million. The Company met with the EPA on April 3, 2013, to present information refuting some of the EPA's findings. The Company is in the process of submitting additional information to the EPA.

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 contractual indemnity is believed by the Company to be unlimited in amount and duration, but requires the Company to contribute up to $1.0 million of the first $5.0 million of indemnified costs for certain of the specified environmental liabilities.

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 as well as a quality system that meets the requirements of the ISO-9001-2008 Standard. The integrity of the

Company's ISO-9001-2008 Standard certification is maintained through surveillance audits by its registrar at regular intervals designed to ensure adherence to the standards. 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.

Table of Contents

The Company has completed studies to assess the adequacy of its PSM practices at its Shreveport refinery with respect to certain consensus codes and standards. During the three months ended March 31, 2013 and 2012, the Company incurred approximately $0.1 million and $0.3 million, respectively, of capital expenditures and expects to incur between $1.0 million and $4.0 million of capital expenditures in 2013 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 OSHA's National Emphasis Program. On March 14, 2011, OSHA issued a Citation and Notification of Penalty (the "Cotton Valley Citation") to the Company as a result of the Cotton Valley inspection, which included a proposed penalty amount of $0.2 million. The Company has contested the Cotton Valley Citation and associated penalty and is currently in negotiations with OSHA to reach a settlement allowing an extended abatement period for a new refinery flare system study and for completion of facility site modifications, including relocation and hardening of structures.

Labor Matters

The Company has employees covered by various collective bargaining agreements. The Cotton Valley and Dickinson collective bargaining agreements were ratified on March 21, 2013 and April 1, 2013, respectively, and both will expire on April 1, 2016.

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 March 31, 2013 and December 31, 2012, the Company had outstanding standby letters of credit of $183.1 million and $222.4 million, respectively, under its senior secured revolving credit facility (the "revolving credit facility"). Refer to Note 7 for additional information regarding the Company's revolving credit facility. The maximum amount of letters of credit the Company could issue at March 31, 2013 and December 31, 2012 under its revolving credit facility is 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 March 31, 2013 and December 31, 2012).

As of March 31, 2013 and December 31, 2012, the Company had availability to issue letters of credit of $482.9 million and $355.1 million, respectively, under its revolving credit facility. As of March 31, 2013 and December 31, 2012, the outstanding standby letters of credit issued under the revolving credit facility included a $25.0 million letter of credit issued to a hedging counterparty to support a portion of its fuel products hedging program.

7. Long-Term Debt

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

	March 31, 2013	December 31, 2012
Borrowings under amended and restated senior secured revolving credit agreement with third-party lenders, interest payments monthly, borrowings due June 2016, weighted average rate of 4.25% for the three months ended March 31, 2013	$29.2	$—
Borrowings under 2019 Notes, interest at a fixed rate of 9.375%, interest payments semiannually, borrowings due May 2019, effective interest rate of 9.93% for the three months ended March 31, 2013	600.0	600.0
Borrowings under 2020 Notes, interest at a fixed rate of 9.625%, interest payments semiannually, borrowings due August 2020, effective interest rate of 10.01% for the three months ended March 31, 2013	275.0	275.0
Capital lease obligations, at various interest rates, interest and principal payments monthly through January 2027	5.3	5.5
Less unamortized discounts	(16.5)	(17.0)
Total long-term debt	893.0	863.5
Less current portion of long-term debt	0.7	0.8
	$892.3	$862.7

Table of Contents

9 5/8% Senior 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 5/8% of senior notes due August 1, 2020 (the "2020 Notes") in a private placement pursuant to Section 4(a)(2) of the Securities Act of 1933, as amended (the "Securities Act"), to eligible purchasers at a discounted price of 98.25 percent of par. The 2020 Notes were resold to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to persons outside the United States pursuant to Regulation S under the Securities Act. The Company received net proceeds of $262.6 million, net of discount, underwriters' fees and expenses, which the Company used to fund a portion of the purchase price of the Royal Purple Acquisition. Refer to Note 3 for additional information regarding the Royal Purple Acquisition.

Interest on the 2020 Notes is paid semiannually in arrears on February 1 and August 1 of each year, beginning on February 1, 2013. The 2020 Notes will mature on August 1, 2020, unless redeemed prior to maturity. The 2020 Notes are jointly and severally guaranteed on a senior unsecured basis by all of the Company's current operating subsidiaries and certain of the Company's future operating subsidiaries, with the exception of Calumet Finance Corp. (a wholly owned Delaware corporation that is minor and was organized for the sole purpose of being a co-issuer of certain of the Company's indebtedness, including the 2020 Notes). The 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 indenture governing the 2020 Notes.

The indenture governing the 2020 Notes contains 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 Notes are rated investment grade by both Moody's Investors Service, Inc. and Standard & Poor's Ratings Services and no Default or Event of Default, each as defined in the indenture governing the 2020 Notes, has occurred and is continuing, many of these covenants will be suspended.

On June 29, 2012, in connection with the issuance and sale of the 2020 Notes, the Company entered into a registration rights agreement (the "Registration Rights Agreement") with the initial purchasers of the 2020 Notes obligating the Company to use reasonable best efforts to file an exchange registration statement with the SEC, so that holders of the 2020 Notes can offer to exchange the 2020 Notes for registered notes having substantially the same terms as the 2020 Notes and evidencing the same indebtedness as the 2020 Notes. The Company must use reasonable best efforts to cause the exchange offer registration statement to become effective by June 28, 2013 and remain effective until 180 days after the closing of the exchange. Additionally, the Company has agreed to commence the exchange offer promptly after the exchange offer registration statement is declared effective by the SEC and use reasonable best efforts to complete the exchange offer not later than 60 days after such effective date. Under certain circumstances, in lieu of a registered exchange offer, the Company must use reasonable best efforts to file a shelf registration statement for the resale of the 2020 Notes. If the Company fails to satisfy these obligations on a timely basis, the annual interest borne by the 2020 Notes will be increased by up to 1.0% per annum until the exchange offer is completed or the shelf registration statement is declared effective.

Upon the occurrence of certain change of control events, each holder of the 2020 Notes will have the right to require that the Company repurchase all or a portion of such holder's 2020 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.

9 3/8% Senior 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 3/8% of senior notes due May 1, 2019 (the "2019 Notes issued in April 2011") in a private placement pursuant to Section 4(a)(2) of the Securities Act to eligible purchasers at par. The 2019 Notes issued in April 2011 were resold to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to persons outside the United States pursuant to Regulation S under the Securities

Act. The Company received proceeds of $389.0 million net of underwriters' 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 Superior Acquisition, the Company issued and sold $200.0 million in aggregate principal amount of 9 3/8% of senior notes due May 1, 2019 (the "2019 Notes issued in September 2011") in a private placement pursuant to Section 4(a)(2) under the Securities Act to eligible purchasers at a discounted price of 93 percent of par. The 2019 Notes issued in September 2011 were resold to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to persons outside the United States pursuant to Regulation S under the Securities Act. The Company

Table of Contents

received proceeds of $180.3 million net of discount, underwriters' fees and expenses, which the Company used to fund a portion of the purchase price of the Superior Acquisition. 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."

Interest on the 2019 Notes is paid semiannually in arrears on May 1 and November 1 of each year, beginning on November 1, 2011. The 2019 Notes will mature on May 1, 2019, unless redeemed prior to maturity. The 2019 Notes are jointly and severally guaranteed on a senior unsecured basis by all of the Company's current operating subsidiaries and certain of the Company's future operating subsidiaries, with the exception of Calumet Finance Corp. (a wholly owned Delaware corporation that is minor and was organized for the sole purpose of being a co-issuer of certain of the Company's indebtedness, including the 2019 Notes). The 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 2019 Notes.

The indentures governing the 2019 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 2019 Notes are rated investment grade by both Moody's Investors Service, Inc. and Standard & Poor's Ratings Services and no Default or Event of Default, each as defined in the indentures governing the 2019 Notes, has occurred and is continuing, many of these covenants will be suspended.

Upon the occurrence of certain change of control events, each holder of the 2019 Notes will have the right to require that the Company repurchase all or a portion of such holder's 2019 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.

On December 16, 2011, the Company filed exchange offer registration statements for the 2019 Notes with the SEC, which were declared effective on January 3, 2012. The exchange offers were completed on February 2, 2012, thereby fulfilling all of the requirements of the 2019 Notes registration rights agreements by the specified dates.

Amended and Restated Senior Secured Revolving Credit Facility

The Company has an $850.0 million senior secured revolving credit facility, which is its primary source of liquidity for cash needs in excess of cash generated from operations. The revolving credit facility matures in June 2016 and currently 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 March 31, 2013, the margin was 100 basis points for prime and 225 basis points for LIBOR; however, the margin can fluctuate quarterly based on the Company's average availability for additional borrowings under the revolving credit facility in the preceding calendar quarter.

In addition to paying interest monthly 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 0.375% to 0.50% per annum depending on the average daily available unused borrowing capacity. The Company also pays a customary letter of credit fee, including a fronting fee of 0.125% per annum of the stated amount of each outstanding letter of credit, and customary agency fees.

The borrowing capacity at March 31, 2013 under the revolving credit facility was $695.2 million. As of March 31, 2013, the Company had $29.2 million in outstanding borrowings under the revolving credit facility and outstanding standby letters of credit of $183.1 million, leaving $482.9 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 cash, accounts receivable, inventory and certain other personal property.

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 (i) 12.5% of the lesser of (a) the Borrowing Base (as defined in the revolving credit agreement) (without giving effect to the LC Reserve (as defined in the revolving credit agreement)) and (b) the credit agreement commitments then in effect and (ii) $46.4 million, (as increased, upon the effectiveness of the increase in the maximum availability under the revolving credit facility, by the same percentage as the percentage increase in the revolving credit agreement commitments), then the Company will be required to

Table of Contents

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.

Maturities of Long-Term Debt

As of March 31, 2013, maturities of the Company's long-term debt are as follows (in millions):

Year	Maturity
2013	$0.5
2014	0.4
2015	0.3
2016	29.6
2017	0.4
Thereafter	878.3
Total	$909.5

8. Derivatives

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

- crude oil purchases;
- refined product sales;
- 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") and Western Canadian Select ("WCS").

The Company does not hold or issue derivative instruments for trading purposes.

The Company recognizes all derivative instruments at their fair values (see Note 9) as either current assets or current liabilities on 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 and liabilities on the Company's condensed consolidated balance sheets as of March 31, 2013 and December 31, 2012 (in millions):

Table of Contents

	March 31, 2013			December 31, 2012		
	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	$32.0	$(30.2)	$1.8	$24.9	$(14.4)	$10.5
Gasoline swaps	1.5	(1.5)	—	5.2	(4.9)	0.3
Diesel swaps	3.0	(6.0)	(3.0)	7.0	(14.9)	(7.9)
Jet fuel swaps	5.2	(3.4)	1.8	8.0	(7.8)	0.2
Total derivative instruments designated as hedges	41.7	(41.1)	0.6	45.1	(42.0)	3.1
Derivative instruments not designated as hedges:						
Fuel products segment:						
Crude oil swaps	1.8	(2.1)	(0.3)	0.1	(0.1)	—
Crude oil basis swaps	8.7	(8.9)	(0.2)	0.1	(0.1)	—
Gasoline swaps	0.9	—	0.9	—	—	—
Diesel swaps	1.2	(1.2)	—	5.1	(5.1)	—
Specialty products segment: (1)						
Crude oil swaps	—	—	—	1.6	(1.6)	—
Total derivative instruments not designated as hedges	12.6	(12.2)	0.4	6.9	(6.9)	—
Total derivative instruments	$54.3	$(53.3)	$1.0	$52.0	$(48.9)	$3.1

(1) From time-to time, the Company has entered into crude oil swaps to economically hedge a portion of its exposures to price risk related to these commodities in its specialty products segment. The Company has not designated these derivative instruments as cash flow hedges.

Table of Contents

	March 31, 2013			December 31, 2012		
	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	$(17.0)	$30.2	$13.2	$(41.1)	$14.4	$(26.7)
Gasoline swaps	(5.3)	1.5	(3.8)	(2.8)	4.9	2.1
Diesel swaps	(39.9)	6.0	(33.9)	(25.2)	14.9	(10.3)
Jet fuel swaps	(8.6)	3.4	(5.2)	(10.1)	7.8	(2.3)
Total derivative instruments designated as hedges	(70.8)	41.1	(29.7)	(79.2)	42.0	(37.2)
Derivative instruments not designated as hedges:						
Fuel products segment:						
Crude oil swaps	(2.7)	2.1	(0.6)	(10.8)	0.1	(10.7)
Crude oil basis swaps	(0.5)	8.9	8.4	(3.5)	0.1	(3.4)
Gasoline swaps	(3.5)	—	(3.5)	(2.2)	—	(2.2)
Diesel swaps	(1.6)	1.2	(0.4)	(1.2)	5.1	3.9
Specialty products segment: (1)						
Crude oil swaps	—	—	—	—	1.6	1.6
Total derivative instruments not designated as hedges	(8.3)	12.2	3.9	(17.7)	6.9	(10.8)
Total derivative instruments	$(79.1)	$53.3	$(25.8)	$(96.9)	$48.9	$(48.0)

(1) From time-to-time, the Company has entered into crude oil swaps to economically hedge a portion of its exposures to price risk related to these commodities in its specialty products segment. The Company has not designated these derivative instruments as cash flow hedges.

The Company accounts for certain derivatives hedging purchases of crude oil and sales of gasoline, diesel and jet fuel as cash flow hedges. The derivatives 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 derivatives designated as hedging payments of interest are recorded in interest expense in the unaudited condensed consolidated statements of operations upon payment of interest. The Company assesses, both at inception of the 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 and fuel products sales. These derivatives can be combined with a swap contract in order to create a more effective hedge. The Company has entered into crude oil basis swaps for 2013 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.

To the extent a derivative instrument designated as a 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. 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 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 on derivative instruments in the unaudited condensed consolidated statements of operations. Unrealized gains and losses related to discontinued cash flow hedges that were previously accumulated in accumulated other comprehensive income (loss) will remain in accumulated other comprehensive income (loss) until the underlying transaction is

Table of Contents

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 on derivative instruments.

Effective January 1, 2012, 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, 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 hedge accounting on these derivative instruments has caused the Company to recognize derivative losses of $5.4 million and derivative gains of $27.2 million in realized gain (loss) on derivative instruments, respectively, in the unaudited condensed consolidated statements of operations for the three months ended March 31, 2013 and 2012. The discontinuance of hedge accounting on these derivative instruments caused the Company to recognize derivative gains of $3.7 million and $29.3 million, respectively, in unrealized gain on derivative instruments in the unaudited condensed consolidated statements of operations for the three months ended March 31, 2013 and 2012.

For derivative instruments not designated as cash flow hedges and the portion of any cash flow hedge that is determined to be ineffective, the change in fair value of the asset or liability for the period is recorded to unrealized gain on derivative instruments in the unaudited condensed consolidated statements of operations. Upon the settlement of a derivative not designated as a cash flow hedge, the gain or loss at settlement is recorded to realized gain (loss) on derivative instruments 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 hedge accounting. Ineffectiveness has resulted, and the loss of hedge accounting has resulted, in increased volatility in the Company's financial results. However, even though certain derivative instruments may not qualify for 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.

The Company recorded the following amounts in its condensed consolidated balance sheets, unaudited condensed consolidated statements of operations, unaudited condensed consolidated statements of other comprehensive income (loss) and its unaudited condensed consolidated statements of partners' capital as of, and for the three months ended, March 31, 2013 and 2012 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) Three Months Ended March 31, 2013	2012	Amount of Gain (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) into Net Income (Effective Portion) Location of (Gain) Loss	Three Months Ended March 31, 2013	2012	Amount of Gain (Loss) Recognized in Net Income on Derivatives (Ineffective Portion) Location of Gain (Loss)	Three Months Ended March 31, 2013	2012
Fuel products segment:								
Crude oil swaps	$ 13.8	$ 32.8	Cost of sales	$ (4.3)	$ 21.2	Unrealized/ Realized	$ (24.2)	$ 61.6
Gasoline swaps	(9.7)	(58.3)	Sales	(3.8)	(16.3)	Unrealized/ Realized	(0.1)	(18.7)

Diesel swaps	(17.1)	(68.8)	Sales	—	(6.6)	Unrealized/ Realized	(1.6)	(2.6)
Jet fuel swaps	(4.3)	(78.7)	Sales	(3.8)	(43.6)	Unrealized/ Realized	0.5	(4.4)
Specialty products segment:								
Crude oil swaps	—	—	Cost of sales	0.3	2.5	Unrealized/ Realized	—	—
Total	$ (17.3)	$ (173.0)		$ (11.6)	$ (42.8)		$ (25.4)	$ 35.9

The Company recorded the following gains (losses) in its unaudited condensed consolidated statements of operations for the three months ended March 31, 2013 and 2012 related to its derivative instruments not designated as cash flow hedges (in millions):

Table of Contents

Type of Derivative	Amount of Gain (Loss) Recognized in Realized Gain (Loss) on Derivative Instruments Three Months Ended March 31, 2013	2012	Amount of Gain (Loss) Recognized in Unrealized Gain on Derivative Instruments Three Months Ended March 31, 2013	2012
Fuel products segment:				
Crude oil swaps	$(5.5)	$0.4	$39.7	$1.7
Crude oil basis swaps	0.2	—	11.6	—
Gasoline swaps	0.3	—	(1.3)	—
Diesel swaps	1.6	—	(5.4)	—
Jet fuel swaps	—	—	—	—
Specialty products segment:				
Crude oil swaps	1.7	—	(1.6)	—
Natural gas swaps	—	(1.4)	—	(1.5)
Interest rate swaps	—	(0.4)	—	0.7
Total	$(1.7)	$(1.4)	$43.0	$0.9

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.

The Company is exposed to credit risk in the event of nonperformance by its counterparties on these derivative transactions. The Company does not expect nonperformance on any derivative instruments, however, no assurances can be provided. The Company's credit exposure related to these derivative instruments is represented by the fair value of contracts reported as derivative assets. As of March 31, 2013, the Company had one counterparty, in which derivatives held were net assets, totaling $1.0 million. As of December 31, 2012, the Company had two counterparties, in which the derivatives held were net assets, totaling $3.1 million. To manage credit risk, the Company selects and periodically reviews counterparties based on credit ratings. The Company primarily executes its derivative instruments with large financial institutions that have ratings of at least Baa2 and BBB by Moody's and S&P, respectively. In the event of default, the Company would potentially be subject to losses on derivative instruments with mark to market gains. The Company requires collateral from its counterparties when the fair value of the derivatives exceeds agreed upon thresholds in its master derivative contracts with these counterparties. No such collateral was held by the Company as of March 31, 2013 or December 31, 2012. The Company's contracts with these counterparties allow for netting of derivative instruments executed under each contract. Collateral received from counterparties is reported in other current liabilities, and collateral held by counterparties is reported in deposits, on the Company's condensed consolidated balance sheets and is not netted against derivative assets or liabilities. As of March 31, 2013 and December 31, 2012, the Company had provided its counterparties with no collateral except for a $25.0 million letter of credit provided to one counterparty to support crack spread hedging. For financial reporting purposes, the Company does not offset the collateral provided to a counterparty against the fair value of its obligation to that counterparty. Any outstanding collateral is released to the Company upon settlement of the related derivative instrument liability.

Certain of the Company's outstanding derivative instruments are subject to credit support agreements with the applicable counterparties which contain provisions setting certain credit thresholds above which the Company may be required to post agreed-upon collateral, such as cash or letters of credit, with the counterparty to the extent that the Company's mark-to-market net liability, if any, on all outstanding derivatives exceeds the credit threshold amount per such credit support agreement. In certain cases, the Company's credit threshold is dependent upon the Company's maintenance of certain corporate credit ratings with Moody's and S&P. In the event that the Company's corporate credit rating was lowered below its current level by either Moody's or S&P, such counterparties would have the right to reduce the applicable threshold to zero and demand full collateralization of the Company's net liability position on outstanding derivative instruments. As of March 31, 2013 and December 31, 2012, there was a net liability of $5.3

million and $7.5 million, respectively, associated with the Company’s outstanding derivative instruments subject to such requirements. In addition, 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 effective portion of the cash flow hedges classified in accumulated other comprehensive loss was $19.7 million and $14.0 million, respectively, as of March 31, 2013 and December 31, 2012. Absent a change in the fair market value of the

Table of Contents

underlying transactions, the following other comprehensive income (loss) at March 31, 2013 will be reclassified to earnings by December 31, 2016 with balances being recognized as follows (in millions):

Year	Accumulated Other Comprehensive Income (Loss)
2013	$ 2.4
2014	(14.5)
2015	(7.7)
2016	0.1
Total	$ (19.7)

Based on fair values as of March 31, 2013, the Company expects to reclassify $1.2 million of net losses on derivative instruments from accumulated other comprehensive loss to earnings during the next twelve months due to actual crude oil purchases and gasoline, diesel and jet fuel sales. However, the amounts actually realized will be dependent on the fair values as of the dates of settlement.

Crude Oil Swap — Specialty Products Segment

At March 31, 2013, the Company did not have any crude oil derivatives related to future crude oil purchases in its specialty products segment.

At December 31, 2012, the Company had purchased a crude oil swap for 200,000 bbls in the second quarter of 2012 related to future crude oil purchases in its specialty products segment, which was not designated as a cash flow hedge. The Company subsequently sold a crude oil derivative swap in the third quarter of 2012, and the net impact of these two derivatives is a net gain of $1.6 million that has been recorded to unrealized loss in the consolidated statements of operations for the year ended December 31, 2012. This gain was realized in January 2013 upon settlement and was recorded to realized gain (loss) on derivative instruments in the unaudited condensed consolidated statements of operations.

Crude Oil Contracts — Fuel Products Segment

Crude Oil Swap Contracts

At March 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)
Second Quarter 2013	2,275,000	25,000	$99.93
Third Quarter 2013	1,426,000	15,500	95.62
Fourth Quarter 2013	1,104,000	12,000	93.41
Calendar Year 2014	5,110,000	14,000	89.47
Calendar Year 2015	4,781,500	13,100	89.49
Calendar Year 2016	366,000	1,000	85.88
Totals	15,062,500		
Average price			$91.84

At March 31, 2013, the Company had the following derivatives related to crude oil purchases in its fuel products segment, none of which are designated as cash flow hedges:

Table of Contents

Crude Oil Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Swap ($/Bbl)
Second Quarter 2013	637,000	7,000	$98.72
Third Quarter 2013	368,000	4,000	96.58
Fourth Quarter 2013	368,000	4,000	96.58
Totals	1,373,000		
Average price			$97.57

At December 31, 2012, 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 2013	1,665,000	18,500	$101.67
Second Quarter 2013	1,911,000	21,000	100.22
Third Quarter 2013	1,426,000	15,500	95.62
Fourth Quarter 2013	1,104,000	12,000	93.41
Calendar Year 2014	5,110,000	14,000	89.47
Calendar Year 2015	4,781,500	13,100	89.49
Totals	15,997,500		
Average price			$92.85

At December 31, 2012, the Company had the following derivatives related to crude oil purchases in its fuel products segment, none of which are designated as cash flow hedges:

Crude Oil Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Swap ($/Bbl)
First Quarter 2013	630,000	7,000	$101.34
Second Quarter 2013	455,000	5,000	98.56
Third Quarter 2013	368,000	4,000	96.58
Fourth Quarter 2013	368,000	4,000	96.58
Totals	1,821,000		
Average price			$98.72

Crude Oil Basis Swap Contracts

During 2012 and 2013 the Company 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 and pricing differentials between LLS and NYMEX WTI. At March 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 cash flow hedges:

Crude Oil Basis Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Differential to NYMEX WTI ($/Bbl)
Second Quarter 2013	724,000	7,956	$(26.89)
Third Quarter 2013	736,000	8,000	(15.73)
Fourth Quarter 2013	184,000	2,000	(23.75)
Totals	1,644,000		
Average price			$(21.54)

At December 31, 2012, the Company had the following derivatives related to crude oil basis swaps in its fuel products segment, none of which are designated as cash flow hedges:

Table of Contents

Crude Oil Basis Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Differential to NYMEX WTI ($/Bbl)
First Quarter 2013	180,000	2,000	$(23.75)
Second Quarter 2013	364,000	4,000	(27.38)
Third Quarter 2013	184,000	2,000	(23.75)
Fourth Quarter 2013	184,000	2,000	(23.75)
Totals	912,000		
Average differential			$(25.20)

Fuel Products Swap Contracts

Diesel Swap Contracts

At March 31, 2013, the Company had the following derivatives related to diesel and jet fuel 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)
Second Quarter 2013	546,000	6,000	$122.74
Third Quarter 2013	874,000	9,500	122.23
Fourth Quarter 2013	828,000	9,000	120.82
Calendar Year 2014	3,835,000	10,507	116.00
Calendar Year 2015	4,781,500	13,100	115.81
Calendar Year 2016	366,000	1,000	112.43
Totals	11,230,500		
Average price			$116.97

At March 31, 2013, the Company had the following derivatives related to diesel and jet fuel sales in its fuel products segment, none of which are designated as cash flow hedges:

Diesel Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
Second Quarter 2013	364,000	4,000	$126.82
Third Quarter 2013	276,000	3,000	124.17
Fourth Quarter 2013	276,000	3,000	124.17
Totals	916,000		
Average price			$125.22

At December 31, 2012, the Company had the following derivatives related to diesel and jet fuel 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)
Second Quarter 2013	546,000	6,000	$122.74
Third Quarter 2013	874,000	9,500	122.23
Fourth Quarter 2013	828,000	9,000	120.82
Calendar Year 2014	3,835,000	10,507	116.00
Calendar Year 2015	4,781,500	13,100	115.81
Totals	10,864,500		
Average price			$117.13

Table of Contents

At December 31, 2012, the Company had the following derivatives related to diesel and jet fuel sales in its fuel products segment, none of which are designated as cash flow hedges:

Diesel Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
First Quarter 2013	540,000	6,000	$ 130.57
Second Quarter 2013	364,000	4,000	126.82
Third Quarter 2013	276,000	3,000	124.17
Fourth Quarter 2013	276,000	3,000	124.17
Totals	1,456,000		
Average price			$ 127.20

Jet Fuel Swap Contracts

At March 31, 2013, the Company had the following derivatives related to diesel and 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)
Second Quarter 2013	819,000	9,000	$ 129.20
Third Quarter 2013	368,000	4,000	125.13
Fourth Quarter 2013	276,000	3,000	122.36
Calendar Year 2014	1,275,000	3,493	116.64
Totals	2,738,000		
Average price			$ 122.11

At December 31, 2012, the Company had the following derivatives related to diesel and 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 2013	1,035,000	11,500	$ 127.39
Second Quarter 2013	819,000	9,000	129.20
Third Quarter 2013	368,000	4,000	125.13
Fourth Quarter 2013	276,000	3,000	122.36
Calendar Year 2014	1,275,000	3,493	116.64
Totals	3,773,000		
Average price			$ 123.56

Gasoline Swap Contracts

At March 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)
Second Quarter 2013	910,000	10,000	$ 121.20
Third Quarter 2013	184,000	2,000	114.73
Totals	1,094,000		
Average price			$ 120.11

At March 31, 2013, the Company had the following derivatives related to gasoline sales in its fuel products segment, none of which are designated as cash flow hedges:

Table of Contents

Gasoline Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
Second Quarter 2013	273,000	3,000	$121.41
Third Quarter 2013	92,000	1,000	105.50
Fourth Quarter 2013	92,000	1,000	105.50
Totals	457,000		
Average price			$115.00

At December 31, 2012, 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 2013	630,000	7,000	$113.59
Second Quarter 2013	546,000	6,000	116.32
Third Quarter 2013	184,000	2,000	114.73
Totals	1,360,000		
Average price			$114.84

At December 31, 2012, the Company had the following derivatives related to gasoline sales in its fuel products segment, none of which are designated as cash flow hedges:

Gasoline Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
First Quarter 2013	90,000	1,000	$105.50
Second Quarter 2013	91,000	1,000	105.50
Third Quarter 2013	92,000	1,000	105.50
Fourth Quarter 2013	92,000	1,000	105.50
Totals	365,000		
Average price			$105.50

9. Fair Value Measurements

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

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

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

Table of Contents

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 BBB by Moody's and S&P, respectively.

To estimate the fair values of the Company's derivative instruments, the Company uses the market approach. Under this approach, the fair values of the Company's derivative instruments for crude oil, crude oil basis, gasoline, diesel, jet fuel, natural gas and interest rate swaps are determined primarily based on inputs that are readily available in public markets or can be derived from information available in publicly quoted markets. Generally, the Company obtains this data through surveying its counterparties and performing various analytical tests to validate the data. In situations where the Company obtains inputs via quotes from its counterparties, it verifies the reasonableness of these quotes via similar quotes from another counterparty as of each date for which financial statements are prepared. The Company also includes an adjustment for non-performance risk in the recognized measure of fair value of all of the Company's derivative instruments. The adjustment reflects the full credit default spread ("CDS") applied to a net exposure by counterparty. When the Company is in a net asset position it uses its counterparty's CDS, or a peer group's estimated CDS when a CDS for the counterparty is not available. The Company uses its own peer group's estimated CDS when it is in a net liability position. As a result of applying the applicable CDS at March 31, 2013, the Company's asset was reduced by less than $0.1 million and the liability was reduced by approximately $0.9 million. As a result of applying the CDS at December 31, 2012, the Company's asset was reduced by $0.1 million and the liability was reduced by approximately $0.2 million.

Based on the use of various unobservable inputs, principally non-performance risk and unobservable inputs in forward years for crude oil, crude oil basis, gasoline, jet fuel, diesel, natural gas and interest rate swaps, 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 has consistently applied these valuation techniques in all periods presented and believes it has obtained the most accurate information available for the types of derivative instruments it holds. See Note 8 for further information on derivative instruments.

Pension Assets

Pension assets are reported at fair value using quoted market prices in the accompanying unaudited condensed consolidated financial statements. The Company's investments associated with its Pension Plan (as such term is hereinafter defined) primarily consist of (i) cash and cash equivalents, (ii) mutual funds that are publicly traded, (iii) a commingled fund and (iv) a balanced fund. The mutual and balanced funds are publicly traded and market prices are readily available; thus, these investments are categorized as Level 1. The commingled fund is categorized as Level 2 because inputs used in its valuation are not quoted prices in active markets that are indirectly observable and is valued at the net asset value of shares held by the Pension Plan at quarter end. See Note 12 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 fair value of the Company's Liability Awards are updated each balance sheet date based on the closing unit price on the balance sheet date. See Note 11 for further information on Liability Awards.

Renewable Identification Numbers Obligation

The Company's Renewable Identification Numbers ("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 1 and is measured at fair value using the market approach based on quoted prices from an independent pricing service.

Table of Contents

Hierarchy of Recurring Fair Value Measurements

The Company's recurring assets and liabilities measured at fair value at March 31, 2013 and December 31, 2012 were as follows (in millions):

	March 31, 2013				December 31, 2012			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Derivative assets:								
Crude oil swaps	$—	$—	$1.5	$1.5	$—	$—	$10.5	$10.5
Crude oil basis swaps	—	—	(0.2)	(0.2)	—	—	—	—
Gasoline swaps	—	—	0.9	0.9	—	—	0.3	0.3
Diesel swaps	—	—	(3.0)	(3.0)	—	—	(7.9)	(7.9)
Jet fuel swaps	—	—	1.8	1.8	—	—	0.2	0.2
Total derivative assets	—	—	1.0	1.0	—	—	3.1	3.1
Pension plan investments	37.6	2.7	—	40.3	38.9	2.7	—	41.6
Total recurring assets at fair value	$37.6	$2.7	$1.0	$41.3	$38.9	$2.7	$3.1	$44.7
Liabilities:								
Derivative liabilities:								
Crude oil swaps	$—	$—	$12.6	$12.6	$—	$—	$(35.8)	$(35.8)
Crude oil basis swaps	—	—	8.4	8.4	—	—	(3.4)	(3.4)
Gasoline swaps	—	—	(7.3)	(7.3)	—	—	(0.1)	(0.1)
Diesel swaps	—	—	(34.3)	(34.3)	—	—	(6.4)	(6.4)
Jet fuel swaps	—	—	(5.2)	(5.2)	—	—	(2.3)	(2.3)
Total derivative liabilities	—	—	(25.8)	(25.8)	—	—	(48.0)	(48.0)
RINs Obligation	—	(10.6)	—	(10.6)	—	(0.8)	—	(0.8)
Liability Awards	(3.7)	—	—	(3.7)	(2.2)	—	—	(2.2)
Total recurring liabilities at fair value	$(3.7)	$(10.6)	$(25.8)	$(40.1)	$(2.2)	$(0.8)	$(48.0)	$(51.0)

The table below sets forth a summary of net changes in fair value of the Company's Level 3 financial assets and liabilities for the three months ended March 31, 2013 and 2012 (in millions):

	Three Months Ended March 31,	
	2013	2012
Fair value at January 1,	$(44.9)	$14.9
Realized (gain) loss on derivative instruments	8.6	(9.4)
Unrealized gain on derivative instruments	24.5	26.0
Change in fair value of cash flow hedges	(17.3)	(173.0)
Settlements	4.3	50.8
Transfers in (out) of Level 3	—	—
Fair value at March 31,	$(24.8)	$(90.7)
Total gain included in net income attributable to changes in unrealized gain relating to financial assets and liabilities held as of March 31,	$24.5	$26.0

All settlements from derivative instruments that are deemed "effective" and were designated as cash flow hedges are included in sales for gasoline, diesel and jet fuel derivatives, cost of sales for crude oil and natural gas derivatives, and interest expense for interest rate derivatives in the unaudited condensed consolidated statements of operations in the period that the hedged cash flow occurs. Any “ineffectiveness” associated with these derivative instruments is recorded in earnings in realized gain (loss) on derivative instruments in the unaudited condensed consolidated statements of operations. All settlements from derivative instruments not designated as cash flow hedges are recorded in realized gain (loss) on derivative instruments in the unaudited condensed consolidated statements of operations. See Note 8 for further information on derivative instruments.

Nonrecurring Fair Value Measurements

Certain nonfinancial assets and liabilities are measured at fair value on a nonrecurring basis and are subject to fair value adjustments in certain circumstances, such as when there is evidence of impairment. Assets and liabilities acquired in business combinations are recorded at their fair value as of the date of acquisition. Refer to Note 3 for the fair values of assets acquired and liabilities assumed in connection with the Missouri, TruSouth, Royal Purple, Montana and San Antonio 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 definite-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 were 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 their respective fair values.

Debt

The estimated fair value of long-term debt at March 31, 2013 consists primarily of the 2019 Notes, 2020 Notes and borrowings under the Company’s revolving credit facility. The estimated fair value of long-term debt at December 31, 2012 consists primarily of the 2019 and 2020 Notes. The fair values of the Company’s 2019 Notes were based upon quoted market prices in an active market and are classified as Level 1. The fair values of the Company’s 2020 Notes were based upon directly observable inputs and are classified as Level 2. The carrying value of borrowings, if any, under the Company’s revolving credit facility approximates its fair value as determined by discounted cash flows and is classified as Level 3. Capital lease obligations approximate their fair values as determined by discounted cash flows and are classified as Level 3. See Note 7 for further information on long-term debt.

The Company’s carrying and estimated fair value of the Company’s financial instruments, carried at adjusted historical cost, at March 31, 2013 and December 31, 2012 were as follows (in millions):

	March 31, 2013		December 31, 2012	
	Fair Value	Carrying Value	Fair Value	Carrying Value
Financial Instrument:				
2019 Notes	$668.0	$588.0	$658.8	$587.6
2020 Notes	$309.7	$270.5	$301.8	$270.4
Revolving credit facility	$29.2	$29.2	$—	$—
Capital lease and other obligations	$5.3	$5.3	$5.5	$5.5

10. Partners’ Capital

On January 8, 2013, the Company completed a public offering of its common units in which it sold 5,750,000 common units, including the overallotment option of 750,000 common units, to the underwriters of the offering at a price to the public of $31.81 per common unit. The proceeds received by the Company from this offering (net of underwriting discounts, commissions and expenses but before its general partner’s capital contribution) were $175.5 million and were used to repay

Table of Contents

borrowings under its revolving credit facility and for general partnership purposes. Underwriting discounts totaled $7.4 million. The Company's general partner contributed $3.7 million to maintain its 2% general partner interest.
The Company's distribution policy is defined in its partnership agreement. For the three months ended March 31, 2013 and 2012, the Company made distributions of $44.5 million and $28.2 million, respectively, to its partners. For the three months ended March 31, 2013 and 2012, the general partner was allocated $3.2 million and $0.5 million, respectively, in incentive distribution rights.

11. Unit-Based Compensation

A summary of the Company's nonvested phantom units as of March 31, 2013 and the changes during the three months ended March 31, 2013 is presented below:

Nonvested Phantom Units	Grant	Weighted Average Grant Date Fair Value Per Unit
Nonvested at December 31, 2012	835,927	$27.57
Granted	60,746	37.82
Vested	(56,202)	33.40
Forfeited	—	—
Nonvested at March 31, 2013	840,471	$24.84

For the three months ended March 31, 2013 and 2012, compensation expense of $2.5 million and $0.1 million, respectively, was recognized in the unaudited condensed consolidated statements of operations related to vested phantom unit grants, including $1.7 million attributable to Liability Awards for the three months ended March 31, 2013. See Note 9 for further information on the fair value of the Liability Awards. As of March 31, 2013 and 2012, there was a total of $20.9 million and $7.1 million, respectively, of unrecognized compensation costs related to nonvested phantom unit grants, including $15.2 million attributable to Liability Awards for the three months ended March 31, 2013. These costs are expected to be recognized over a weighted-average period of approximately three years.

12. Employee Benefit Plans

The components of net periodic pension and other postretirement benefits cost for the three months ended March 31, 2013 and 2012 were as follows (in millions):

	For the Three Months Ended March 31,			
	2013		2012	
	Pension Benefits	Other Post Retirement Employee Benefits	Pension Benefits	Other Post Retirement Employee Benefits
Service cost	$0.1	$—	$0.2	$ 0.1
Interest cost	0.6	—	0.6	0.1
Expected return on assets	(0.5)	—	(0.6)	—
Amortization of net loss	0.2	—	0.2	—
Net periodic benefit cost	$0.4	$—	$0.4	$ 0.2

The Company's investments associated with its Pension Plan primarily consist of (i) cash and cash equivalents, (ii) mutual funds that are publicly traded, (iii) a commingled fund and (iv) a balanced fund. The mutual and balanced funds are publicly traded and market prices are readily available; thus, these investments are categorized as Level 1. The commingled fund is categorized as Level 2 because inputs used in its valuation are not quoted prices in active markets that are indirectly observable and is valued at the net asset value of the shares held by the Pension Plan at quarter end. See Note 9 for the definition of Levels 1, 2 and 3. The Company's Pension Plan assets measured at fair value at March 31, 2013 and December 31, 2012 were as follows (in millions):

35

Table of Contents

	March 31, 2013 Pension Assets		December 31, 2012 Pension Assets	
	Level 1	Level 2	Level 1	Level 2
Cash and cash equivalents	$19.5	$—	$19.3	$—
Equity	7.0	—	5.9	—
Foreign equities	2.4	—	2.3	—
Commingled fund	—	2.7	—	2.7
Balanced fund	—	—	3.0	—
Fixed income	8.7	—	8.4	—
	$37.6	$2.7	$38.9	$2.7

13. Accumulated Other Comprehensive Loss

The table below sets forth a summary of reclassification adjustments out of accumulated other comprehensive loss in the Company's unaudited condensed consolidated statements of operations for the three months ended March 31, 2013 (in millions):

Components of Accumulated Other Comprehensive Loss	Amount Reclassified From Accumulated Other Comprehensive Loss	Location
Derivative losses reflected in gross profit		
	$(7.6)	Sales
	(4.0)	Cost of sales
	$(11.6)	Total
Amortization of defined benefit pension and post retirement health benefit plans:		
Amortization of net loss	$(0.2)	(1)
	$(0.2)	Total

(1) This accumulated other comprehensive loss component is included in the computation of net periodic pension cost. See Note 12 for additional details.

14. Earnings per Unit

The following table sets forth the computation of basic and diluted earnings per limited partner unit for the three months ended March 31, 2013 and 2012 (in millions, except unit and per unit data):

36

Table of Contents

	Three Months Ended March 31, 2013	2012
Numerator for basic and diluted earnings per limited partner unit:		
Net income	$46.0	$51.9
General partner’s interest in net income	0.9	1.0
General partner’s incentive distribution rights	3.2	0.5
Nonvested share based payments	0.2	0.3
Net income available to limited partners	$41.7	$50.1
Denominator for basic and diluted earnings per limited partner unit:		
Basic weighted average limited partner units outstanding	62,831,155	51,684,741
Effect of dilutive securities:		
Participating securities — phantom units	186,714	51,655
Diluted weighted average limited partner units outstanding	63,017,869	51,736,396
Limited partners’ interest basic net income per unit	$0.67	$0.97
Limited partners’ interest diluted net income per unit	$0.66	$0.97

15. Segments and Related Information

a. Segment Reporting

The Company has two reportable segments: specialty products and fuel products. The specialty products segment produces a variety of lubricating oils, solvents, waxes, synthetic lubricants, asphalt and other by-products. These products are sold to customers who purchase these products primarily as raw material components for basic automotive, industrial and consumer goods. The specialty products segment also blends and markets through the Company’s brand Royal Purple. The fuel products segment produces a variety of fuel and fuel-related products including gasoline, diesel, jet fuel and heavy fuel oils. The Company is also engaged in the resale of purchased crude oil to third party customers. The Company sells the majority of the fuel products it produces to markets located in Arkansas, Canada, Idaho, Iowa, Louisiana, Michigan, Minnesota, Montana, North Dakota, South Dakota, Texas and Wisconsin. The Company also has the ability to ship additional fuel products to the Midwest region and the northern states bordering Canada through the Enterprise and Magellan pipelines should the need arise. The assets and results of the operations from such assets acquired as a result of the Montana Acquisition have been included in both the specialty products and fuel products segment since the date of acquisition, October 1, 2012. The assets and results of the operations from such assets acquired as a result of the San Antonio Acquisition have been included in the fuel products segment since the date of acquisition, January 2, 2013. The assets and results of operations from such assets acquired as a result of the Missouri, TruSouth and Royal Purple Acquisitions have been included in the specialty products segment since their dates of acquisition, January 3, 2012, January 6, 2012 and July 3, 2012, respectively.

The accounting policies of the 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 2012 Annual Report. The Company evaluates segment performance based on operating income (loss). The Company accounts for intersegment sales and transfers at cost plus a specified mark-up. Reportable segment information is as follows (in millions):

Table of Contents

Three Months Ended March 31, 2013	Specialty Products	Fuel Products	Combined Segments	Eliminations	Consolidated Total
Sales:					
External customers	$535.1	$783.5	$1,318.6	$—	$1,318.6
Intersegment sales	—	22.6	22.6	(22.6)	—
Total sales	$535.1	$806.1	$1,341.2	$(22.6)	$1,318.6
Depreciation and amortization	23.9	8.0	31.9	—	31.9
Operating income	4.5	49.9	54.4	—	54.4
Reconciling items to net income:					
Interest expense					(24.8)
Gain on derivative instruments					15.9
Other					0.7
Income tax expense					(0.2)
Net income					$46.0

Three Months Ended March 31, 2012	Specialty Products	Fuel Products	Combined Segments	Eliminations	Consolidated Total
Sales:					
External customers	$562.5	$607.1	$1,169.6	$—	$1,169.6
Intersegment sales	309.7	9.2	318.9	(318.9)	—
Total sales	$872.2	$616.3	$1,488.5	$(318.9)	$1,169.6
Depreciation and amortization	18.6	4.5	23.1	—	23.1
Operating income	28.7	6.3	35.0	—	35.0
Reconciling items to net income:					
Interest expense					(18.6)
Gain on derivative instruments					35.4
Other					0.2
Income tax expense					(0.1)
Net income					$51.9

b. Geographic Information

International sales accounted for less than 10% of consolidated sales in each of the three months ended March 31, 2013 and 2012. All of the Company's long-lived assets are domestically located.

c. Product Information

The Company offers specialty products primarily in six general categories consisting of lubricating oils, solvents, waxes, packaged and synthetic specialty products, fuels and asphalt and other by-products. Fuel products primarily consist of gasoline, diesel, jet fuel and heavy fuel oils. The following table sets forth the major product category sales (in millions):

Table of Contents

	Three Months Ended March 31,					
	2013			2012		
Specialty products:						
Lubricating oils	$239.9	18	%	$288.8	25	%
Solvents	131.7	10	%	134.8	12	%
Waxes	32.8	2	%	37.2	3	%
Packaged and synthetic specialty products	59.5	5	%	26.2	2	%
Fuels	0.6	—	%	0.9	—	%
Asphalt and other by-products	70.6	6	%	74.6	6	%
Total	$535.1	41	%	$562.5	48	%
Fuel products:						
Gasoline	327.3	25	%	293.4	25	%
Diesel	305.3	23	%	240.7	21	%
Jet fuel	50.2	4	%	45.9	4	%
Heavy fuel oils and other	100.7	7	%	27.1	2	%
Total	$783.5	59	%	$607.1	52	%
Consolidated sales	$1,318.6	100	%	$1,169.6	100	%

d. Major Customers

During the three months ended March 31, 2013 and 2012, the Company had no customer that represented 10% or greater of consolidated sales.

16. Subsequent Events

On April 1, 2013, the Company completed a public offering of its common units in which it sold 5,250,000 common units to the underwriters of the offering at a price to the public of $37.50 per common unit. On April 4, 2013, the overallotment option of 787,500 common units was exercised by the underwriters at a price to the public of $37.50 per common unit. The proceeds received by the Company from this offering (net of underwriting discounts, commissions and expenses but before its general partner’s capital contribution) were $217.1 million and were used for general partnership purposes. Underwriting discounts totaled $9.1 million. The Company’s general partner contributed $4.6 million to maintain its 2% general partner interest.

On April 22, 2013, the Company declared a quarterly cash distribution of $0.68 per unit on all outstanding common units, or approximately $51.9 million (including the general partner’s incentive distribution rights) in aggregate, for the quarter ended March 31, 2013. The distribution will be paid on May 15, 2013 to unitholders of record as of the close of business on May 3, 2013. This quarterly distribution of $0.68 per unit equates to $2.72 per unit per year, or approximately $207.6 million (including the general partner’s incentive distribution rights) in aggregate on an annualized basis.

The fair value of the Company’s derivatives increased by approximately $35.0 million subsequent to March 31, 2013 to a net asset of approximately $10.0 million. The fair value of the Company’s long-term debt, excluding capital leases, has increased by approximately $13.0 million subsequent to March 31, 2013.

Table of Contents

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

The historical condensed consolidated financial statements included in this Quarterly Report reflect all of the assets, liabilities and results of operations of Calumet Specialty Products Partners, L.P. ("Calumet," the "Company," "we," "our," or "us"). The following discussion analyzes the financial condition and results of operations of the Company for the three months ended March 31, 2013 and 2012. Unitholders should read the following discussion and analysis of the financial condition and results of operations for Calumet in conjunction with our 2012 Annual Report and the historical unaudited condensed consolidated financial statements and notes of the Company included elsewhere in this Quarterly Report.

Overview

We are a leading independent producer of high-quality, specialty hydrocarbon products in North America. We are headquartered in Indianapolis, Indiana and own facilities primarily located in Louisiana, Wisconsin, Montana, Texas and Pennsylvania. We own and lease additional facilities, primarily related to production and distribution of specialty products, throughout the 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 asphalt. 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 brand. In our fuel products segment we process crude oil into a variety of fuel and fuel-related products, including gasoline, diesel, jet fuel and heavy fuel oils, as well as reselling purchased crude oil to third party customers. In connection with our production of specialty products and fuel products, we also produce asphalt and a limited number of other by-products.

First Quarter 2013 Update

Our specialty products segment generated a gross profit margin of 11.8% during the first quarter 2013, consistent with the same period in 2012. Our specialty products segment performance was impacted by lower average selling prices per barrel quarter over quarter which outpaced the decline in the average cost of crude oil per barrel. In addition, specialty products sales volume declined 3.5% quarter over quarter, excluding the impact of incremental sales from the Royal Purple and Montana Acquisitions.

The fuel products segment generated a gross profit margin of 9.1% during the first quarter of 2013 compared to 2.9% in the same period of 2012 due primarily to widening market crack spreads and lower realized losses on crack spread hedges. Although the segment benefited from the incremental gross profit from acquisitions, lower production rates at our Shreveport refinery due to various reliability issues and a fuel products inventory build at the Superior refinery in advance of the planned April 2013 plantwide turnaround had a negative impact on segment performance, as sales volumes of legacy operations were down 13.6% quarter over quarter. Additionally, in accordance with the Renewable Fuel Standard mandating the blending of biofuels in transportation fuels, our Renewable Identification Numbers ("RINs") expense increased $7.5 million quarter over quarter as a result of increased RINs market pricing. As of March 31, 2013, we have 16.4 million barrels of crack spread derivatives outstanding for calendar years 2013 through 2016 at an average price of $28.28 per barrel, an increase of $6.88 over the average price as of March 31, 2012.

Due to the widespread geography of our operations, our financial performance is impacted by the relative pricing variation between and among various types of crude oil. The following table details average crude oil price differentials of Light Louisiana Sweet ("LLS") crude oil, Bakken light crude oil, Western Canadian Select ("WCS") crude oil and Bow River crude oil to NYMEX WTI crude oil (on a per barrel basis):

Average Per Barrel Crude Oil Pricing Differential to NYMEX WTI	Q1 2013	Q4 2012	Q1 2012
LLS	$19.57	$21.29	$16.86
Bakken	$(1.91)	$(3.05)	$(12.38)
WCS	$(26.62)	$(26.23)	$(26.53)
Bow River	$(30.97)	$(16.38)	$(20.00)

During the first quarter 2013, WCS heavy crude oil averaged $26.62 per barrel below NYMEX WTI, an increase of $0.09 from the same period in 2012. During the three months ended March 31, 2013, Bakken light crude oil averaged $1.91 per barrel below NYMEX WTI, a decrease of $10.47 from the same period in 2012. Both the WCS and Bakken differentials to NYMEX WTI provide an unhedged crude oil cost advantage for our Superior refinery relative to NYMEX WTI pricing. During the first quarter 2013, Bow River heavy crude oil averaged $30.97 per barrel below NYMEX WTI, an increase of

$10.97 over the same period in 2012, providing an unhedged crude oil cost advantage for our Montana refinery relative to NYMEX WTI pricing. On the product selling price side, while Group 3 diesel product pricing differentials to U.S. Gulf Coast pricing were not quite as strong as in the fourth quarter 2012, we saw more favorable product pricing differentials in the first quarter 2013, with the Group 3 gasoline pricing differential to U.S. Gulf Coast, for example, widening $2.07 per barrel compared to the average gasoline differential in the fourth quarter 2012. As we currently use U.S. Gulf Coast fuel product swaps to hedge a portion of our Group 3 fuel products selling price exposure, we continue to benefit when Group 3 pricing strengthens relative to U.S. Gulf Coast pricing.

On January 2, 2013, we completed the acquisition of NuStar Energy L.P.'s San Antonio, Texas refinery, together with related assets and the assumption of certain liabilities and obligations (the "San Antonio Acquisition"). Total consideration for the San Antonio Acquisition was approximately $117.7 million, net of cash acquired and excluding certain purchase price adjustments. The refinery has total crude oil throughput capacity of 14,500 bpd and primarily produces jet fuel, diesel, other fuel products and specialty solvents. The San Antonio Acquisition was funded with borrowings under our revolving credit facility with the balance through cash on hand. We believe the San Antonio Acquisition further diversifies our crude oil feedstock slate, operating asset base and geographical presence.

We used $35.0 million in cash flow from operations during the first quarter of 2013 primarily as a result of increased working capital requirements, primarily from the San Antonio Acquisition and from the winter fill of asphalt inventory. We generated Distributable Cash Flow (as defined below in "Non-GAAP Financial Measures") of $26.4 million and $39.2 million for the first quarter of 2013 and 2012, respectively, and paid distributions of $44.5 million to our unitholders in the first quarter of 2013, an increase of $16.3 million over the same period in 2012. We plan to continue focusing our efforts on generating positive cash flows from operations which we expect will be used to (i) improve our liquidity position, (ii) service our debt obligations, (iii) pay quarterly distributions to our unitholders and (iv) provide funding for general partnership purposes.

Key Performance Measures

Our sales and net income are principally affected by the price of crude oil, demand for specialty and fuel products, 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 mitigate the impact of commodity price fluctuations on our business. The primary purpose of our commodity risk management activities is to economically hedge our cash flow exposure to commodity price risk so that we can meet our cash distribution, debt service and capital expenditure requirements despite fluctuations in crude oil and fuel products prices. We enter into derivative contracts for future periods in quantities that do not exceed our projected purchases of crude oil and natural gas and sales of fuel products. Please read Part I, Item 3 "Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk." As of March 31, 2013, we have hedged refining margins, or crack spreads, on approximately 16.4 million barrels of fuel products through December 2016 at an average refining margin of $28.28 per barrel with average refining margins ranging from a low of $26.32 per barrel in 2015 to a high of $32.13 per barrel in the third quarter of 2013. Please refer to Note 8 — "Derivatives" under Part I, Item 1 "Financial Statements—Notes to Unaudited Condensed Consolidated Financial Statements" and Part I, Item 3 "Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk" for detailed information regarding our derivative instruments and our commodity price risk.

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

- sales volumes;
- production yields; and
- specialty products and fuel products gross profit.

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.

Table of Contents

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 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 a 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 revenues 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, the allocation of by-product (primarily asphalt) losses to the fuel products segment, 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.

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

Table of Contents

Results of Operations for the Three Months Ended March 31, 2013 and 2012

Production Volume. The following table sets forth information about our combined operations. Facility production volume differs from sales volume due to changes in inventories and the sale of purchased fuel product blendstocks such as ethanol, biodiesel and the resale of crude oil in our fuel products segment. The table includes the results of operations at our Missouri facility commencing on January 3, 2012, TruSouth facility commencing January 6, 2012, Royal Purple facility commencing July 3, 2012, Montana refinery commencing October 1, 2012 and San Antonio refinery commencing January 2, 2013.

	Three Months Ended March 31,		
	2013	2012	% Change
	(In bpd)		
Total sales volume (1)	111,789	97,516	14.6 %
Total feedstock runs (2)	110,465	98,203	12.5 %
Facility production: (3)			
Specialty products:			
Lubricating oils	12,127	14,322	(15.3)%
Solvents	8,561	9,107	(6.0)%
Waxes	1,234	1,277	(3.4)%
Packaged and synthetic specialty products (4)	1,950	1,140	71.1 %
Fuels	762	446	70.9 %
Asphalt and other by-products	17,956	15,223	18.0 %
Total	42,590	41,515	2.6 %
Fuel products:			
Gasoline	29,881	24,902	20.0 %
Diesel	23,843	23,122	3.1 %
Jet fuel	4,794	5,456	(12.1)%
Heavy fuel oils and other	6,877	3,419	101.1 %
Total	65,395	56,899	14.9 %
Total facility production (3)	107,985	98,414	9.7 %

(1) Total sales volume includes sales from the production at Calumet’s facilities and certain third-party facilities pursuant to supply and/or processing agreements, sales of inventories and the resale of crude oil to third party customers. Total sales volume includes the sale of purchased fuel product blendstocks such as ethanol and biodiesel as components of finished fuel products in our fuel products segment sales. The increase in total sales volume for the three months ended March 31, 2013 compared to the same quarter in 2012 is due primarily to incremental sales of fuel products, asphalt and packaged and synthetic specialty products resulting from the Royal Purple, Montana and San Antonio acquisitions partially offset by decreased sales of lubricating oils and fuel products at the Shreveport and Superior refineries.

(2) Total feedstock runs represent the barrels per day of crude oil and other feedstocks processed at Calumet’s 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 March 31, 2013 compared to the same period in 2012 is due primarily to incremental feedstock runs resulting from the Royal Purple, Montana and San Antonio Acquisitions, partially offset by reduced run rates at our Shreveport refinery during 2013 due to unscheduled downtime associated with various operational reliability issues and planned turnaround activity in 2013.

(3) Total facility production represents the barrels per day of specialty products and fuel products yielded from processing crude oil and other feedstocks at Calumet’s facilities and at certain third-party facilities pursuant to supply and/or processing agreements. The difference between total facility production and total feedstock runs is

primarily a result of the time lag between the input of feedstocks and production of finished products and volume loss. The increase in total facility production for the three months ended March 31, 2013 compared to the same period in 2012 is due primarily to incremental production from acquisitions partially offset by lower run rates at the Shreveport refinery as discussed above in footnote 2 of this table.

Table of Contents

(4) Represents production of packaged and synthetic specialty products at our Royal Purple, TruSouth and Missouri facilities.

Table of Contents

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 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 March 31,	
	2013	2012
	(In millions)	
Sales	$1,318.6	$1,169.6
Cost of sales	1,184.2	1,085.4
Gross profit	134.4	84.2
Operating costs and expenses:		
Selling	15.9	4.5
General and administrative	25.1	13.7
Transportation	35.4	27.5
Taxes other than income taxes	3.0	1.7
Other	0.6	1.8
Operating income	54.4	35.0
Other income (expense):		
Interest expense	(24.8)	(18.6)
Realized gain (loss) on derivative instruments	(8.6)	9.4
Unrealized gain on derivative instruments	24.5	26.0
Other	0.7	0.2
Total other income (expense)	(8.2)	17.0
Net income before income taxes	46.2	52.0
Income tax expense	0.2	0.1
Net income	$46.0	$51.9
EBITDA	$100.3	$90.2
Adjusted EBITDA	$80.0	$69.7
Distributable Cash Flow	$26.4	$39.2

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 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.

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.

Table of Contents

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, commercial banks, research analysts and others to meaningfully trend and analyze the 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 capital expenditures, turnaround costs, cash interest expense (consolidated interest expense less non-cash interest expense) and income tax expense.

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 2019 Notes and 2020 Notes (as defined in this Quarterly Report). We are required to report Consolidated Cash Flow to the holders of our 2019 Notes and 2020 Notes and Adjusted EBITDA to the commercial banks under our revolving credit facility, and these measures are used by them to determine our compliance with certain covenants governing those debt instruments. Distributable Cash Flow is used by us, our investors, commercial banks, research analysts and others to analyze our ability to pay distributions. 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, operating income, net cash provided by (used in) operating activities or any other measure of financial performance presented in accordance with GAAP. In evaluating our performance as measured by EBITDA, Adjusted EBITDA and Distributable Cash Flow, our management recognizes and considers the limitations of these measurements. EBITDA, Adjusted EBITDA and Distributable Cash Flow 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 to EBITDA, Adjusted EBITDA and Distributable Cash Flow, and Distributable Cash Flow, Adjusted EBITDA and EBITDA to net cash provided by (used in) operating activities, our most directly comparable GAAP financial performance and liquidity measures, for each of the periods indicated.

Table of Contents

	Three Months Ended March 31, 2013	2012
	(In millions)	
Reconciliation of Net income to EBITDA, Adjusted EBITDA and Distributable Cash Flow:		
Net income	$46.0	$51.9
Add:		
Interest expense	24.8	18.6
Depreciation and amortization	29.3	19.6
Income tax expense	0.2	0.1
EBITDA	$100.3	$90.2
Add:		
Unrealized gain on derivatives	$(24.5)	$(26.0)
Realized gain (loss) on derivatives, not included in net income	(1.3)	1.4
Amortization of turnaround costs	2.6	3.5
Non-cash equity based compensation	2.9	0.6
Adjusted EBITDA	$80.0	$69.7
Less:		
Replacement capital expenditures (1)	$16.4	$5.3
Cash interest expense (2)	23.1	17.2
Turnaround costs	13.9	7.9
Income tax expense	0.2	0.1
Distributable Cash Flow	$26.4	$39.2

(1) Replacement capital expenditures are defined as those capital expenditures which do not increase operating capacity or reduce operating costs and exclude turnaround costs.
(2) Represents consolidated interest expense less non-cash interest expense.

Table of Contents

	Three Months Ended March 31,	
	2013	2012
	(In millions)	
Reconciliation of Distributable Cash Flow, Adjusted EBITDA and EBITDA to Net cash provided by (used in) operating activities:		
Distributable Cash Flow	$26.4	$39.2
Add:		
Replacement capital expenditures (1)	16.4	5.3
Cash interest expense (2)	23.1	17.2
Turnaround costs	13.9	7.9
Income tax expense	0.2	0.1
Adjusted EBITDA	$80.0	$69.7
Less:		
Unrealized gain on derivative instruments	(24.5)	(26.0)
Realized gain (loss) on derivatives, not included in net income	(1.3)	1.4
Amortization of turnaround costs	2.6	3.5
Non-cash equity based compensation	2.9	0.6
EBITDA	$100.3	$90.2
Add:		
Unrealized gain on derivative instruments	(24.5)	(26.0)
Cash interest expense (2)	(23.1)	(17.2)
Non-cash equity based compensation	2.9	0.6
Amortization of turnaround costs	2.6	3.5
Income tax expense	(0.2)	(0.1)
Provision for doubtful accounts	0.3	0.3
Changes in assets and liabilities:		
Accounts receivable	(85.9)	(75.3)
Inventories	(51.4)	1.8
Other current assets	(1.7)	1.0
Turnaround costs	(13.9)	(7.9)
Derivative activity	(1.3)	1.4
Accounts payable	82.6	36.0
Accrued interest payable	5.3	13.8
Accrued income taxes payable	(27.6)	—
Other current liabilities	1.9	(5.2)
Other, including changes in noncurrent liabilities	(0.1)	—
Net cash provided by (used in) operating activities	$(33.8)	$16.9

(1) Replacement capital expenditures are defined as those capital expenditures which do not increase operating capacity or reduce operating costs and exclude turnaround costs.
(2) Represents consolidated interest expense less non-cash interest expense.

Table of Contents

Changes in Results of Operations for the Three Months Ended March 31, 2013 and 2012

Sales. Sales increased $149.0 million, or 12.7%, to $1,318.6 million in the three months ended March 31, 2013 from $1,169.6 million in the same period in 2012. The results of operations related to the Montana Acquisition have been included in both segments since the date of acquisition, October 1, 2012. The results of operations related to the San Antonio Acquisition have been included in the fuel products segment since the date of acquisition, January 2, 2013. The results of operations related to the Missouri, TruSouth and Royal Purple Acquisitions have been included in the specialty products segment since the dates of acquisition, January 3, 2012, January 6, 2012 and July 3, 2012, respectively. Sales for each of our principal product categories in these periods were as follows:

	Three Months Ended March 31,		
	2013	2012	% Change
	(Dollars in millions, except per barrel data)		
Sales by segment:			
Specialty products:			
Lubricating oils	$239.9	$288.8	(16.9)%
Solvents	131.7	134.8	(2.3)%
Waxes	32.8	37.2	(11.8)%
Packaged and synthetic specialty products (1)	59.5	26.2	127.1 %
Fuels (2)	0.6	0.9	(33.3)%
Asphalt and by-products (3)	70.6	74.6	(5.4)%
Total specialty products	$535.1	$562.5	(4.9)%
Total specialty products sales volume (in barrels)	3,419,000	3,427,000	(0.2)%
Average specialty products sales price per barrel	$156.51	$164.14	(4.6)%
Fuel products:			
Gasoline	$331.1	$309.7	6.9 %
Diesel	308.5	279.0	10.6 %
Jet fuel	50.8	57.8	(12.1)%
Heavy fuel oils and other (4)	100.7	27.1	271.6 %
Hedging activities loss	(7.6)	(66.5)	(88.6)%
Total fuel products	$783.5	$607.1	29.1 %
Total fuel products sales volume (in barrels)	6,642,000	5,447,000	21.9 %
Average fuel products sales price per barrel (excluding hedging activities)	$119.11	$123.67	(3.7)%
Average fuel products sales price per barrel (including hedging activities)	$117.96	$111.46	5.8 %
Total sales	$1,318.6	$1,169.6	12.7 %
Total sales volume (in barrels)	10,061,000	8,874,000	13.4 %

(1) Represents production of packaged and synthetic specialty products at the Royal Purple, TruSouth and Missouri facilities.

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

(3) Represents asphalt and by-products produced in connection with the production of specialty and fuel products at the Shreveport, Superior, Montana, Princeton and Cotton Valley refineries.

(4) Represents 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 parties.

The components of the $27.4 million specialty products segment sales decrease for the three months ended March 31, 2013 were as follows:

49

Table of Contents

	Dollar Change (Dollars in millions)
Acquisitions	$32.8
Sales price	(40.5)
Volume	(19.7)
Total specialty products segment sales decrease	$(27.4)

Specialty products segment sales decreased $27.4 million quarter over quarter, or 4.9%, primarily as a result of a decreased average selling price per barrel, partially offset by incremental sales from acquisitions. Legacy operations' sales decreased $40.5 million due to lower average selling prices per barrel of 7.5% driven by lower lubricating oils, packaged and synthetic products and asphalt average selling prices per barrel while the average cost of crude oil per barrel decreased 8.4%. The Royal Purple and Montana Acquisitions increased sales by $32.8 million which was all related to packaged and synthetic specialty products and asphalt. Legacy operations' sales volumes decreased 3.5% as compared to the same period in 2012, which resulted in a $19.7 million decrease in sales. The decrease in sales volume is due primarily to lower sales volumes of lubricating oils and waxes, partially offset by increased sales volume of packaged and synthetic specialty products due to market conditions.

The components of the $176.4 million fuel products segment sales increase for the three months ended March 31, 2013 were as follows:

	Dollar Change (Dollars in millions)
Acquisitions	$222.1
Sales price	(13.2)
Volume	(91.4)
Hedging activities	58.9
Total fuels products segment sales increase	$176.4

Fuel products segment sales increased $176.4 million quarter over quarter, or 29.1%, due primarily to incremental sales from acquisitions and a $58.9 million decrease in realized derivative losses recorded in sales on our fuel products cash flow hedges, partially offset by decreased sales volume from our legacy operations and a decrease in the average selling price per barrel. The acquisitions of Montana in 2012 and San Antonio in 2013 increased sales by $222.1 million. Calumet's legacy operations' sales volumes decreased 13.6% as a result of decreased run rates, primarily due to unscheduled down time caused by various reliability issues at the Shreveport refinery and fuel products inventory build in preparation for the April 2013 plantwide turnaround at the Superior refinery. Legacy operations' average selling price per barrel (excluding the impact of those realized hedging losses reflected in sales) decreased $2.82, or 2.3%, resulting in a $13.2 million decrease in sales, compared to a 12.2% decrease in the average price of crude oil per barrel.

Gross Profit. Gross profit increased $50.2 million, or 59.6%, to $134.4 million in the three months ended March 31, 2013 from $84.2 million in the same period in 2012. Gross profit for our specialty products and fuel products segments were as follows:

Table of Contents

	Three Months Ended March 31,		
	2013	2012	% Change
	(Dollars in millions, except per barrel data)		
Gross profit by segment:			
Specialty products:			
Gross profit	$63.2	$66.5	(5.0)%
Percentage of sales	11.8%	11.8%	
Specialty products gross profit per barrel	$18.48	$19.40	(4.7)%
Fuel products:			
Gross profit excluding hedging activities	83.1	63.0	31.9%
Hedging activities	(11.9)	(45.3)	(73.7)%
Gross profit	71.2	17.7	302.3%
Percentage of sales	9.1%	2.9%	
Fuel products gross profit per barrel (excluding hedging activities)	$12.51	$11.57	8.1%
Fuel products gross profit per barrel (including hedging activities)	$10.72	$3.26	228.8%
Total gross profit	$134.4	$84.2	59.6%
Percentage of sales	10.2%	7.2%	

The components of the $3.3 million specialty products segment gross profit decrease for the three months ended March 31, 2013 were as follows:

	Dollar Change (Dollars in millions)	% of Sales
Quarter ended March 31, 2012 reported gross profit	$66.5	11.8%
Acquisitions	9.6	1.8%
Sales price	(40.5)	(7.6)%
Volume	(3.7)	—%
Cost of materials	32.7	6.1%
Operating costs	(1.4)	(0.3)%
Quarter ended March 31, 2013 reported gross profit	$63.2	11.8%

The decrease in specialty products segment gross profit of $3.3 million quarter over quarter was due primarily to decreased average selling prices per barrel and decreased sales volume partially offset by lower cost of materials and acquisitions. Sales price and cost of materials, net, from our legacy operations decreased gross profit by $7.8 million, as the average selling price per barrel of specialty products decreased 7.5% compared to an 8.4% decrease in the average cost of crude oil per barrel. The Royal Purple and Montana Acquisitions contributed $9.6 million of gross profit.

The components of the $53.5 million fuel products segment gross profit increase for the three months ended March 31, 2013 were as follows:

	Dollar Change (Dollars in millions)	% of Sales
Quarter ended March 31, 2012 reported gross profit	$17.7	2.9%
Acquisitions	19.3	(0.2)%
Sales price	(13.2)	(1.7)%
Volume	(15.8)	—%
Hedging activities	33.4	4.3%
Cost of materials	38.9	5.0%
Operating costs	(9.1)	(1.2)%
Quarter ended March 31, 2013 reported gross profit	$71.2	9.1%

51

Table of Contents

The increase in fuel products segment gross profit of $53.5 million quarter over quarter was due primarily to increased gross profit from our legacy operations due to widening crack spreads as the decline in sales price was outpaced by the decline in cost of materials experienced in our local markets, decreased realized losses on derivatives of $33.4 million and $19.3 million of gross profit contributed from acquisitions, partially offset by decreased sales volume from our legacy operations. The 13.6% decline in legacy operations' sales volume was primarily due to unscheduled down time caused by various reliability issues at the Shreveport refinery and fuel products inventory build in preparation for the April 2013 plantwide turnaround at the Superior refinery. Operating costs increased $9.1 million primarily as a result of higher RINs costs in our legacy operations.

Selling. Selling expenses increased $11.4 million, or 253.3%, to $15.9 million in the three months ended March 31, 2013 from $4.5 million in the same period in 2012. This increase was due primarily to increased amortization expense of $6.2 million primarily related to the recording of intangible assets associated with the Royal Purple Acquisition, additional employee compensation costs from the Royal Purple Acquisition with no similar expenses in the prior year and increased advertising expenses of $3.0 million.

General and administrative. General and administrative expenses increased $11.4 million, or 83.2%, to $25.1 million in the three months ended March 31, 2013 from $13.7 million in the same period in 2012. The increase was due primarily to increased incentive compensation costs of $4.0 million, increased professional fees of $3.5 million due primarily to consulting fees related to our enterprise resource planning system installation and additional employee compensation costs from the Royal Purple, Montana and San Antonio Acquisitions, with no similar expenses in the prior year.

Transportation. Transportation expenses increased $7.9 million, or 28.7%, to $35.4 million in the three months ended March 31, 2013 from $27.5 million in the same period in 2012. This increase is due primarily to incremental transportation expenses related to sales from the Royal Purple, Montana and San Antonio Acquisitions.

Interest expense. Interest expense increased $6.2 million, or 33.3%, to $24.8 million in the three months ended March 31, 2013 from $18.6 million in the three months ended March 31, 2012, due primarily to additional outstanding long-term debt in the form of 2020 Notes issued to partially fund the Royal Purple Acquisition.

Derivative activity. The following table details the impact of our derivative instruments on the unaudited condensed consolidated statements of operations for the three months ended March 31, 2013 and 2012.

	Three Months Ended March 31,			
	2013		2012	
	(In millions)			
Derivative loss reflected in sales	$(7.6	)	$(66.5	)
Derivative gain (loss) reflected in cost of sales	(4.0	)	23.7	
Derivative losses reflected in gross profit	$(11.6	)	$(42.8	)
Realized gain (loss) on derivative instruments	$(8.6	)	$9.4	
Unrealized gain on derivative instruments	24.5		26.0	
Total derivative gain (loss) reflected in the unaudited condensed consolidated statements of operations	$4.3		$(7.4	)
Total loss on derivative settlements	$(21.5	)	$(32.0	)

Realized gain (loss) on derivative instruments. Realized gain (loss) on derivative instruments decreased $18.0 million to an $8.6 million loss in the three months ended March 31, 2013 from a $9.4 million gain for the three months ended March 31, 2012. The change was due primarily to an increased realized loss of approximately $32.6 million related to the settlements of derivative instruments used to economically hedge crack spreads at our Superior refinery that are not accounted for as hedges for accounting purposes and therefore are not reflected in gross profit. Partially offsetting this increased realized loss was a decreased realized loss of approximately $10.9 million due primarily to hedging ineffectiveness related to settlements of cash flow hedges and realized gains of approximately $3.0 million related to natural gas and crude oil derivative settlements included in our specialty products segment but not designated as cash flow hedges.

Unrealized gain on derivative instruments. Unrealized gain on derivative instruments decreased $1.5 million to $24.5 million in the three months ended March 31, 2013 from $26.0 million in the three months ended March 31, 2012. The change was due primarily to decreased unrealized gains of approximately $15.6 million in 2013 related to derivative instruments used to economically hedge crack spreads that are not accounted for as cash flow hedges for accounting purposes. Partially offsetting this decreased unrealized gain was increased unrealized gain ineffectiveness of approximately $13.0 million.

Table of Contents

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 2012 Annual Report. There have been no material changes in that information other than as discussed below. Also, see Note 7 — "Long-Term Debt" under Part I, Item 1 "Financial Statements—Notes to Unaudited Condensed Consolidated Financial Statements" for additional discussion related to our long-term debt.

Our principal sources of cash have historically included cash flow from operations, proceeds from public equity offerings, proceeds from notes offerings and bank borrowings. Principal uses of cash have included capital expenditures, acquisitions, distributions to our limited partners and general partner and debt service. 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 credit facilities. 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 settlements of our derivative activities. Gains and losses from derivative instruments that qualify as effective cash flow hedges are deferred in accumulated other comprehensive loss, but may impact operating cash flow in the period settled.

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

	Three Months Ended March 31, 2013	2012
	(In millions)	
Net cash provided by (used in) operating activities	$(35.0)	$16.9
Net cash used in investing activities	(148.0)	(54.2)
Net cash provided by financing activities	161.3	43.6
Net increase (decrease) in cash and cash equivalents	$(21.7)	$6.3

Operating Activities. Operating activities used cash of $35.0 million during the three months ended March 31, 2013 compared to providing cash of $16.9 million during the same period in 2012. The decrease in cash provided by operating activities is due primarily to an increase in working capital requirements, primarily increased accounts receivable and inventories for the three months ended March 31, 2013 compared to the same period in 2012 and decreased net income of $5.9 million.

Investing Activities. Cash used in investing activities increased to $148.0 million during the three months ended March 31, 2013 compared to $54.2 million during the three months ended March 31, 2012. The increase is due primarily to the higher purchase price of the San Antonio Acquisition of $117.7 million in 2013 compared to a combined purchase price of $46.4 million for the Missouri and TruSouth Acquisitions, which closed during 2012 and $9.2 million contributed to the Dakota Prairie Refining, LLC joint venture, with no such contributions in the prior period.

Financing Activities. Financing activities provided cash of $161.3 million in the three months ended March 31, 2013 compared to $43.6 million during the three months ended March 31, 2012. This change period over period is due primarily to net proceeds from the January 2013 public offering of common units (including our general partner's contribution) of $179.2

million, partially offset by decreased revolver borrowings of $45.0 million and increased distributions to our unitholders of $16.3 million.

Equity Transactions

On January 8, 2013, we completed a public offering of our common units in which we sold 5,750,000 common units, including the overallotment option of 750,000 common units, to the underwriters of the offering at a price to the public of $31.81 per common unit. The proceeds received by us from this offering (net of underwriting discounts, commissions and expenses but before our general partner’s capital contribution) were $175.5 million and were used to repay borrowings under our revolving credit facility and for general partnership purposes. Underwriting discounts totaled $7.4 million. Our general partner contributed $3.7 million to maintain its 2% general partner interest.

On April 1, 2013, we completed a public offering of our common units in which we sold 5,250,000 common units to the underwriters of the offering at a price to the public of $37.50 per common unit. On April 4, 2013, the overallotment option of 787,500 common units was exercised at a price to the public of $37.50 per common unit. The proceeds received by us from this offering (net of underwriting discounts, commissions and expenses but before our general partner’s capital contribution) were $217.1 million and were used for general partnership purposes. Underwriting discounts totaled $9.1 million. Our general partner contributed $4.6 million to maintain its 2% general partner interest.

On April 22, 2013, we declared a quarterly cash distribution of $0.68 per unit on all outstanding common units, or approximately $51.9 million (including our general partner’s incentive distribution rights) in aggregate, for the quarter ended March 31, 2013. The distribution will be paid on May 15, 2013 to unitholders of record as of the close of business on May 3, 2013. This quarterly distribution of $0.68 per unit equates to $2.72 per unit per year, or approximately $207.6 million (including our general partner’s incentive distribution rights) in aggregate on an annualized basis.

Acquisitions

On January 2, 2013, we completed the acquisition of the San Antonio, Texas refinery, together with the associated crude oil pipeline, crude oil terminal, other operating and logistics assets and inventories of NuStar Refining, LLC and NuStar Logistics, L.P., both wholly owned subsidiaries of NuStar Energy L.P., for aggregate consideration of approximately $117.7 million, subject to certain post-closing adjustments. The San Antonio refinery produces jet fuel, diesel, other fuel products and specialty solvents. The San Antonio Acquisition was funded primarily with borrowings under our revolving credit facility with the balance through cash on hand. We believe the San Antonio Acquisition further diversifies our crude oil feedstock slate, operating asset base and geographical presence.

Joint Venture

On February 7, 2013, we 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. The refinery is expected to process 20,000 bpd of Bakken crude oil to serve product demand in the region. Construction of the refinery began during the first quarter of 2013 with startup of the refinery expected late in the fourth quarter of 2014. The refinery’s total construction cost is estimated at approximately $300.0 million. The capitalization of the joint venture is expected to be funded through contributions of $150.0 million from MDU and $75.0 million from us and proceeds of $75.0 million from an unsecured syndicated term loan facility with the joint venture as the borrower. The term loan facility was funded in April 2013. Funding for the project will occur over the course of the construction period, with the majority of the direct funding by us and MDU expected to occur in 2014. The diesel refinery is expected to be operational in the fourth quarter of 2014. During the three months ended March 31, 2013 we contributed $9.2 million to the Dakota Prairie Refining, LLC joint venture. The joint venture will allocate profits on a 50%/50% basis to us and MDU. We will cover the debt service cost of the lower interest rate term loan facility pursuant to the joint venture agreement. The joint venture will be governed by a board of managers comprised of representatives from both us and MDU. MDU will provide a portion of the crude oil supply to the refinery, as well as natural gas and electricity utility services. We will provide refinery operations, crude oil procurement and refined product marketing expertise to the joint venture.

Capital Expenditures

Our 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.

Table of Contents

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

	Three Months Ended March 31,	
	2013	2012
	(In millions)	
Capital improvement expenditures	$4.7	$4.4
Replacement capital expenditures	7.9	1.3
Environmental capital expenditures	8.5	4.0
Total	$21.1	$9.7

We anticipate that future capital expenditure requirements will be provided primarily through cash from operations and available borrowings under our revolving credit facility. Our environmental capital expenditures have increased during the three months ended March 31, 2013 as compared to the same period in 2012 due primarily to expenditures related to the Global Settlement with the LDEQ and OSHA compliance matters. Please read Note 6 of Part I, Item 1 "Financial Statements—Commitments and Contingencies—Environmental — Occupational Health and Safety" for additional information on the Global Settlement and OSHA compliance issues.

We estimate our replacement and environmental capital expenditures will be approximately $18.0 million per quarter for the remainder of 2013. These estimated amounts for 2013 include a portion of the $1.0 million to $4.0 million in environmental projects to be spent over the next three years as required by our settlement with the LDEQ under the "Small Refinery and Single Site Refining Initiative." Please read Note 6 of Part I, Item 1 "Financial Statements—Commitments and Contingencies—Environmental — Occupational Health and Safety" for additional information.

Additionally, we anticipate turnaround spending requirements will be approximately $50.0 million for the remainder of 2013 related to scheduled turnarounds at our Superior, Montana and San Antonio refineries. We expect these expenditures will be funded primarily through cash flow from operations.

We have several capital improvement projects under consideration including capacity expansions at certain of our facilities, as well as planned investments such as the joint venture located in North Dakota with MDU. We currently estimate that these organic growth opportunities could lead to capital improvement expenditures over the next two years of approximately $400.0 million. Decisions to proceed on such projects are based on several factors, including, but not limited to, feasibility studies, cost estimates, availability of funding sources and, in certain cases, required approval of the board of directors of our general partner. Due to these factors, the estimated amount to be spent in 2013 on capital improvement projects is approximately $100.0 million to $200.0 million.

Debt and Credit Facilities

As of March 31, 2013, our primary debt and credit instruments consisted of:

- an $850.0 million senior secured revolving credit facility maturing in June 2016, 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;
- $600.0 million of 9 3/8% senior notes due 2019 ("2019 Notes"); and
- $275.0 million of 9 5/8% senior notes due 2020 ("2020 Notes").

As of March 31, 2013, we believe we were in compliance with all covenants under the debt instruments in place at March 31, 2013 and have adequate liquidity to conduct our business.

Short Term Liquidity

As of and for the three months ended March 31, 2013, our principal sources of short-term liquidity were (i) $482.9 million of availability under our revolving credit facility and (ii) $10.5 million of cash. Borrowings under our revolving credit facility can be used for, among other things, working capital, capital expenditures, and other lawful partnership purposes including acquisitions.

Borrowings under the revolving credit facility are limited to a borrowing base that is determined based on advance rates of percentages of Eligible Accounts 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 March 31, 2013, we had availability on our revolving credit facility of $482.9 million, based on a $695.2

55

Table of Contents

million borrowing base, $183.1 million in outstanding standby letters of credit and $29.2 million in 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 thirteen lenders with total commitments of $850.0 million. The lenders under our revolving credit facility have a first priority lien on our cash, accounts receivable, inventory and certain other personal property.

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 March 31, 2013 were $131.7 million. Nonetheless, our availability on our revolving credit facility during the peak borrowing days of a quarter has been ample to support our operations and service upcoming requirements. During the quarter ended March 31, 2013, availability for additional borrowings under our revolving credit facility was approximately $271.4 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 March 31, 2013, this margin was 100 basis points for prime and 225 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 0.375% or 0.50% 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 lesser of (a) the Borrowing Base (as defined in the credit agreement) without giving effect to the LC Reserve (as defined in the credit agreement) and (b) the revolving credit facility commitments then in effect and (ii) $45.0 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 (i) 12.5% of the lesser of (a) the Borrowing Base (as defined in the credit agreement) (without giving effect to the LC Reserve (as defined in the credit agreement)) and (b) the credit agreement commitments then in effect and (ii) $46.4 million, we will be required to maintain as of the end of each fiscal quarter a Fixed Charge Coverage Ratio (as defined in the credit agreement) of at least 1.0 to 1.0.

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

For additional information regarding our revolving credit facility, see Note 7 of Part I, Item 1 “Financial Statements—Long-Term Debt” and Note 6 “Long-Term Debt” in Part II, Item 8 “Financial Statements and Supplementary Data” in our 2012 Annual Report.

56

Table of Contents

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, often referred to as our senior notes. All of our outstanding senior notes are unsecured obligations that rank equally with all of our other senior debt obligations to the extent they are unsecured. As of March 31, 2013 and December 31, 2012, we had $600.0 million in 2019 Notes and $275.0 million in 2020 Notes outstanding.

The indentures governing the 2019 and 2020 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 2019 or 2020 Notes are rated investment grade by both Moody's Investors Service, Inc. and Standard & Poor's Ratings Services and no Default or Event of Default, each as defined in the indentures governing the 2019 or 2020 Notes, has occurred and is continuing, many of these covenants will be suspended.

Upon the occurrence of certain change of control events, each holder of the 2019 and 2020 Notes will have the right to require that we repurchase all or a portion of such holder's 2019 and 2020 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 2019 and 2020 Notes, see Note 7 — "Long-Term Debt" under Part I, Item 1 "Financial Statements—Notes to Unaudited Condensed Consolidated Financial Statements" and Note 6 — "Long-Term Debt" in Part II, Item 8 "Financial Statements and Supplementary Data" of our 2012 Annual Report.

Master Derivative Contracts and Collateral Trust Agreement

Under our credit support arrangements, our payment obligations under all of our master derivatives contracts for commodity hedging generally are secured by a first priority lien on our and our subsidiaries' real property, plant and equipment, fixtures, intellectual property, certain financial assets, certain investment property, commercial tort claims, chattel paper, documents, instruments and proceeds of the foregoing (including proceeds of hedge arrangements). We have also issued to one counterparty a $25.0 million standby letter of credit under the revolving credit facility. In the event that such counterparty's exposure to us exceeds $200.0 million, we will be required to post additional collateral support in the form of either cash or letters of credit with the party to enter into additional crack spread hedges with this counterparty. We had no additional letters of credit or cash margin posted with any hedging counterparty as of March 31, 2013. 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 $35.0 million subsequent to March 31, 2013 to a net asset of approximately $10.0 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 to require significant additional collateral to be posted. As a result, we do not expect further increases in fuel products crack spreads to significantly impact our liquidity.

Table of Contents

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 would be 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.

Contractual Obligations and Commercial Commitments

A summary of our total contractual cash obligations as of March 31, 2013 at current maturities and reflects only those line items that have materially changed since December 31, 2012 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 (1)	$558.4	$90.2	$176.9	$167.2	$124.1
Operating lease obligations (2)	105.3	23.8	34.1	21.2	26.2
Letters of credit (3)	183.1	183.1	—	—	—
Purchase commitments (4)	1,367.6	1,254.3	112.9	0.4	—
Financing activities:					
Capital lease obligations	5.3	0.7	0.7	0.7	3.2
Long-term debt obligations, excluding capital lease obligations	904.2	—	—	29.2	875.0
Total obligations	$3,123.9	$1,552.1	$324.6	$218.7	$1,028.5

(1) Interest on long-term debt at contractual rates and maturities relates primarily to our 2019 and 2020 Notes, revolving credit facility and capital lease obligations.
(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 June 2026.
(3) Letters of credit primarily supporting crude oil purchases, precious metals leasing and hedging activities.
(4) Purchase commitments consist primarily of obligations to purchase fixed volumes of crude oil and other feedstocks and finished products for resale from various suppliers based on current market prices at the time of delivery.

In connection with the closing of the acquisition of Penreco on January 3, 2008, we entered into a feedstock purchase agreement with Phillips 66 related to the LVT unit at its Lake Charles, Louisiana refinery (the "LVT Feedstock Agreement"). Pursuant to the LVT Feedstock Agreement, Phillips 66 is obligated to supply a minimum quantity (the "Base Volume") of feedstock for the LVT unit for a term of ten years. Based upon this minimum supply quantity, we expect to purchase $75.5 million of feedstock for the LVT unit in each fiscal year of the term based on pricing estimates as of March 31, 2013. This amount is not included in the table above.

For additional information regarding our expected capital and turnaround expenditures for the remainder of 2013 and 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 months ended March 31, 2013.

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 of our 2012 Annual Report.

58

Table of Contents

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."

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 2012 Annual Report. There have been no material changes in that information other than as discussed below. Also, see Note 8 — "Derivatives" under Part I, Item 1 "Financial Statements—Notes to Unaudited Condensed Consolidated Financial Statements" in this Quarterly Report for additional discussion related to derivative instruments and hedging activities.

Commodity Price Risk

Derivative Instruments

We are exposed to price risks due to fluctuations in the price of crude oil, refined products (primarily in our fuel products segment) 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, futures and options to attempt to reduce our exposure with respect to:

•crude oil purchases;
•refined product sales;
•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, LLS and WCS.

As of March 31, 2013, we have entered into swap contracts on forecasted purchases from 2013 through 2016 for 16.4 million barrels of NYMEX WTI crude oil and forecasted sales of 1.6 million barrels of U.S. Gulf Coast conventional gasoline, 12.1 million barrels of U.S. Gulf Coast ultra-low sulfur diesel and 2.7 million barrels of U.S. Gulf Coast jet fuel. These derivative instruments, on a combined basis, were entered into to hedge a portion of our gross profit in our fuels products segment. Please read Note 8 — "Derivatives" under Part I, Item 1 "Financial Statements—Notes to Unaudited Condensed Consolidated Financial Statements" for a discussion of the accounting treatment for the various types of derivative instruments, and a further discussion of our hedging policies.

We also enter 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 refineries. As of March 31, 2013, we had 1.6 million barrels of crude oil basis swap contracts locking in the differential between NYMEX WTI and WCS crude oil or LLS crude oil. Please read Note 8 — "Derivatives" under Part I, Item 1 "Financial Statements—Notes to Unaudited Condensed Consolidated Financial Statements" for additional information.

The following table provides a summary of the implied crack spreads for the crude oil, diesel, jet fuel and gasoline swaps, as well as our WCS or LLS crude oil versus NYMEX WTI crude oil basis swaps as of March 31, 2013 in our fuels products segment which we disclose in Note 8 — "Derivatives" under Part I, Item 1 "Financial Statements—Notes to Unaudited Condensed Consolidated Financial Statements".

Table of Contents

	Barrels	BPD	Implied Crack Spread ($/Bbl)
Second Quarter 2013	2,912,000	32,000	$31.48
Third Quarter 2013	1,794,000	19,500	32.13
Fourth Quarter 2013	1,472,000	16,000	29.55
Calendar Year 2014	5,110,000	14,000	26.70
Calendar Year 2015	4,781,500	13,100	26.32
Calendar Year 2016	366,000	1,000	26.55
Totals	16,435,500		
Average price			$28.28

Our derivative instruments and overall fuel products 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 March 31, 2013:

	In millions
Crude oil swaps	$16.4
Crude oil basis swaps	$1.6
Diesel swaps	$(12.1)
Jet fuel swaps	$(2.7)
Gasoline swaps	$(1.6)

Interest Rate Risk

We have an $850.0 million revolving credit facility as of March 31, 2013 and December 31, 2012, with borrowings bearing interest at the prime rate or LIBOR, at our option, plus the applicable margin. We have $29.2 million of variable rate debt and no interest rate swaps outstanding as of March 31, 2013. Borrowings under this facility are variable and at the time of borrowing we assess whether or not to enter into an interest rate swap to fix the rate. Holding other variables constant (such as debt levels), a one hundred basis point change in interest rates on our variable rate debt as of March 31, 2013 would be expected to have an impact on net income and cash flows for 2013 of approximately $0.3 million.

For our fixed rate 2019 and 2020 Notes, changes in interest rates will generally affect the fair value, but not our interest expense or cash flows. The following table provides information about the fair value of our debt instruments.

	March 31, 2013		December 31, 2012	
	Fair Value	Carrying Value	Fair Value	Carrying Value
	(In millions)			
Financial Instrument:				
2019 Notes	$668.0	$588.0	$658.8	$587.6
2020 Notes	$309.7	$270.5	$301.8	$270.4

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.

Table of Contents

Item 4. Controls and Procedures

(a) Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) of the Securities Exchange Act of 1934 (the "Exchange Act"), as amended, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Quarterly Report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of March 31, 2013 at the reasonable assurance level.

(b) Changes in Internal Control over Financial Reporting

On January 1, 2013, we implemented an enterprise resource planning ("ERP") system on a company-wide basis, which is expected to improve the efficiency of certain financial and related transaction processes. The implementation resulted in business and operational interruptions, which required changes to our internal controls over financial reporting. We believe we have designed adequate controls into and around the new ERP system, which includes performing significant procedures, both within the ERP and outside the ERP, to monitor, review and reconcile financial activity for the first quarter of fiscal 2013 to ensure ongoing reliability of our financial reporting.

On January 3, 2012, January 6, 2012, July 3, 2012, October 1, 2012 and January 2, 2013, we completed the Missouri, TruSouth, Royal Purple, Montana and San Antonio Acquisitions, respectively, which include certain existing information systems and internal controls over financial reporting that previously existed. We are currently in the process of evaluating and integrating the Missouri, TruSouth, Royal Purple, Montana and San Antonio Acquisitions' historical internal controls over financial reporting with ours. We expect to complete the integration of Missouri, TruSouth, Royal Purple and Montana in fiscal year 2013 and the integration of San Antonio in fiscal year 2014.

Table of Contents

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 incidentental to our business. As a result, we may, at any given time, be a defendant in various legal proceedings and litigation arising in the ordinary course of business. The information provided under Note 6 — "Commitments and Contingencies" in Part I, Item 1 "Financial Statements—Notes to Unaudited Condensed Consolidated Financial Statements" is incorporated herein by reference.

Item 1A. Risk Factors

In addition to the risk factor set forth below, you should carefully consider the risk factors discussed in Part I, Item 1A "Risk Factors" in our 2012 Annual 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 IA "Risk Factors" in our 2012 Annual Report other than with respect to the risk factor discussed below.

Renewable transportation fuels mandates may reduce demand for the petroleum fuels we produce, which could have a material adverse effect on our results of operations and financial condition, and our ability to make distributions to our unitholders.

Pursuant to the Energy Policy Act of 2005 and the Energy Independence and Security Act of 2007, the EPA has issued Renewable Fuels Standards ("RFS") implementing mandates to blend renewable transportation fuels such as, for example, ethanol and advanced biofuels into the petroleum fuels produced in, or imported into, the U.S. Under RFS, the volume of renewable transportation fuels that obligated refineries like the Shreveport, Superior, Montana and San Antonio refineries blend into their finished petroleum fuels increases annually over time until 2022. We may meet these RFS requirements by blending the necessary volumes of renewable transportation fuels obtained from third parties, from purchases of Renewable Identification Number credits ("RINs") in the open market that are generated by third parties, or through a combination of blending of renewable transportation fuels and purchase of RINs. To the extent that we exceed the minimum volumetric requirements for blending of renewable transportation fuels, we generate our own RINs for which we have the option of retaining the RINs for current or future RFS compliance or selling those RINs on the open market.

We currently purchase RINs for some fuel categories on the open market to comply with the RFS and, in the future, we may be required to purchase additional RINs beyond the amount we currently purchase on the open market in order to maintain compliance with the RFS. In 2012, we purchased approximately 38.2 million RINs and sold approximately 5.0 million RINs. The RFS mandate for 2013 has increased, and our recent acquisitions of our Montana and San Antonio refineries in October 2012 and January 2013, respectively, together with other changes in our overall refining system, will impact the total amount of RINs that we may need to obtain in 2013 or future years to comply with the RFS mandate. The purchase price for RINs has increased significantly in 2013 as compared to past years and we cannot currently predict the future prices or availability of RINs or the total extent of our ability to mitigate our future RFS compliance expenses such as, by example, increasing the blending of transportation fuels that qualify for RINs in our refining system or passing on some of the increased costs associated with RFS compliance to our customers. The costs to obtain the necessary number of RINs in 2013 and beyond could be material and have a material adverse effect on our results of operations and financial condition as well as on the refining industry in general. Finally, while there is no current regulatory standard that authenticates RINs that may be purchased on the open market from third parties, we believe that the RINs we purchase are from reputable sources, are valid and serve to demonstrate compliance with applicable RFS requirements.

On October 13, 2010, the EPA granted a partial waiver raising the maximum amount of ethanol allowed under federal law from 10% to 15% for cars and light trucks manufactured since 2007, and on January 21, 2011, EPA extended the maximum allowable ethanol content of 15% to apply to cars and light trucks manufactured since 2001. The maximum amount allowed under federal law currently remains at 10% ethanol for all other vehicles. EPA required that fuel and fuel additive manufacturers take certain steps before introducing gasoline containing 15% ethanol ("E15") into the market, including developing and obtaining EPA approval of a plan to minimize the potential for E15 to be used in vehicles and engines not covered by the partial waiver. EPA has taken several recent actions to authorize the introduction of E15 into the market, including approving, on June 15, 2012, the first plans to minimize the potential for E15 to be used in vehicles and engines not covered by the partial waiver. Existing laws and regulations could change, and the minimum volumes of renewable transportation fuels that must be blended with refined petroleum fuels may increase. Because we do not produce renewable

Table of Contents

transportation fuels at all of our refineries, increasing the volume of renewable transportation fuels that must be blended into our products displaces an increasing volume of our Shreveport, Superior, Montana and San Antonio refineries' fuel products pool, potentially resulting in lower earnings and materially adversely affecting our ability to make distributions.

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

	Total Number of Common Units Purchased	Average Price Paid per Common Unit	Total Number of Common Units Purchased as a Part of Publicly Announced Plans	Maximum Number of Common Units that May Yet be Purchased Under Plans
January 1, 2013 - January 31, 2013	—	$—	—	—
February 1, 2013 - February 28, 2013 (1)	8,900	38.04	—	—
March 1, 2013 - March 31, 2013 (1)	117,071	39.46	—	—
Total	125,971	$39.36	—	—

(1) A total of 125,971 common units were purchased by our general partner, Calumet GP, LLC, related to the Calumet GP, LLC Long-Term Incentive Plan (the "LTIP"). 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 2012 Annual Report.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

None.

Item 5. Other Information

None.

Table of Contents

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)).
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.
**	XBRL (Extensible Business Reporting Language) information is furnished and not filed or a part of the registration statement or prospectus for purposes of sections 11 or 12 of the Securities Act of 1933, as amended, is deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, as amended, and otherwise is not subject to liability under these sections.

Table of Contents

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

		CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
	By:	Calumet GP, LLC, its general partner
Date: May 10, 2013	By:	/s/ R. Patrick Murray, II R. Patrick Murray, II Senior Vice President, Chief Financial Officer and Secretary of Calumet GP, LLC (Principal Accounting and Financial Officer) (Authorized Person and Principal Accounting Officer)

Table of Contents

Index to Exhibits

Exhibit Number	Description
3.1	Certificate of Limited Partnership of Calumet Specialty Products Partners, L.P. (incorporated by reference to Exhibit 3.1 to the Registrant's Registration Statement on Form S-1 filed with the Commission on October 7, 2005 (File No. 333-128880)).
3.2	Amended and Restated Limited Partnership Agreement of Calumet Specialty Products Partners, L.P. (incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the Commission on February 13, 2006 (File No. 000-51734)).
3.3	Amendment No. 1 to the First Amended and Restated Agreement of Limited Partnership of Calumet Specialty Products Partners, L.P. (incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the Commission on July 11, 2006 (File No. 000-51734)).
3.4	Amendment No. 2 to First Amended and Restated Agreement of Limited Partnership of Calumet Specialty Products Partners, L.P. (incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the Commission on April 18, 2008 (File No. 000-51734)).
3.5	Certificate of Formation of Calumet GP, LLC (incorporated by reference to Exhibit 3.3 of Registrant's Registration Statement on Form S-1 filed with the Commission on October 7, 2005 (File No. 333-128880)).
3.6	Amended and Restated Limited Liability Company Agreement of Calumet GP, LLC (incorporated by reference to Exhibit 3.2 to the Registrant's Current Report on Form 8-K filed with the Commission on February 13, 2006 (File No. 000-51734)).
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.

**	XBRL (Extensible Business Reporting Language) information is furnished and not filed or a part of the registration statement or prospectus for purposes of sections 11 or 12 of the Securities Act of 1933, as amended, is deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, as amended, and otherwise is not subject to liability under these sections.

66