Calumet Specialty Products Partners, L.P.
Form 10-Q
November 07, 2012
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 SEPTEMBER 30, 2012
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. (Check one):

Large accelerated filer	¨	Accelerated filer	x
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 Act). Yes ¨ No x

At November 7, 2012, there were 57,529,778 common units outstanding.

Table of Contents

CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
QUARTERLY REPORT
For the Three and Nine Months Ended September 30, 2012
Table of Contents

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 the required audits or required operational changes included in our settlement with the Louisiana Department of Environmental Quality (“LDEQ”) 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 revenues 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, 2011 (“2011 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

	September 30, 2012 (Unaudited)	December 31, 2011
	(In thousands, except unit data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$190,538	$64
Accounts receivable:		
Trade	261,142	208,928
Other	2,999	3,137
	264,141	212,065
Inventories	494,112	497,740
Derivative assets	—	58,502
Prepaid expenses and other current assets	10,315	8,179
Deposits	3,949	2,094
Total current assets	963,055	778,644
Property, plant and equipment, net	863,364	842,101
Goodwill	161,150	48,335
Other intangible assets, net	203,752	22,675
Other noncurrent assets, net	47,840	40,303
Total assets	$2,239,161	$1,732,058
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$336,034	$302,826
Accrued interest payable	30,843	10,500
Accrued salaries, wages and benefits	19,507	13,481
Taxes payable	16,710	13,068
Other current liabilities	9,202	4,600
Current portion of long-term debt	783	551
Derivative liabilities	95,802	43,581
Total current liabilities	508,881	388,607
Pension and postretirement benefit obligations	18,315	26,957
Other long-term liabilities	1,132	1,055
Long-term debt, less current portion	862,513	586,539
Total liabilities	1,390,841	1,003,158
Commitments and contingencies		
Partners' capital:		
Limited partners' interest (57,529,778 and 51,529,778 units issued and outstanding, respectively, at September 30, 2012 and December 31, 2011)	877,258	666,471
General partner's interest	29,740	23,902
Accumulated other comprehensive income (loss)	(58,678)	38,527
Total partners' capital	848,320	728,900
Total liabilities and partners' capital	$2,239,161	$1,732,058

See accompanying notes to unaudited condensed consolidated financial statements.

4

Table of Contents

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In thousands, except per unit data)			
Sales	$1,179,818	$777,780	$3,436,400	$2,116,790
Cost of sales	1,021,412	681,179	3,064,942	1,922,760
Gross profit	158,406	96,601	371,458	194,030
Operating costs and expenses:				
Selling	15,002	2,809	26,668	8,220
General and administrative	12,810	11,339	41,333	26,923
Transportation	28,404	23,696	80,903	69,462
Taxes other than income taxes	1,723	1,683	5,371	4,246
Insurance recoveries	—	—	—	(8,698)
Other	1,613	543	4,856	1,781
Operating income	98,854	56,531	212,327	92,096
Other income (expense):				
Interest expense	(24,271)	(12,577)	(61,247)	(30,602)
Debt extinguishment costs	—	—	—	(15,130)
Realized gain (loss) on derivative instruments	(10,156)	(3,814)	20,486	(5,798)
Unrealized loss on derivative instruments	(22,101)	(20,335)	(11,337)	(23,876)
Other	268	45	382	148
Total other expense	(56,260)	(36,681)	(51,716)	(75,258)
Net income before income taxes	42,594	19,850	160,611	16,838
Income tax expense	178	236	610	674
Net income	$42,416	$19,614	$160,001	$16,164
Allocation of net income:				
Net income	$42,416	$19,614	$160,001	$16,164
Less:				
General partner’s interest in net income	848	392	3,200	323
General partner’s incentive distribution rights	1,637	40	3,256	40
Nonvested share based payments	262	—	947	—
Net income available to limited partners	$39,669	$19,182	$152,598	$15,801
Weighted average limited partner units outstanding:				
Basic	57,746	41,828	54,827	39,352
Diluted	57,826	41,837	54,867	39,368
Limited partners’ interest basic and diluted net income per unit	$0.69	$0.46	$2.78	$0.40
Cash distributions declared per limited partner unit	$0.59	$0.50	$1.68	$1.45

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 September 30,		For the Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In thousands)		(In thousands)	
Net income	$42,416	$19,614	$160,001	$16,164
Other comprehensive loss:				
Cash flow hedges:				
Cash flow hedge loss reclassified to net income	41,766	34,350	137,797	81,294
Change in fair value of cash flow hedges	(83,391)	(37,762)	(236,279)	(180,537)
Defined benefit pension and retiree health benefit plans	1,009	61	1,277	183
Total other comprehensive loss	(40,616)	(3,351)	(97,205)	(99,060)
Comprehensive income (loss) attributable to partners' capital	$1,800	$16,263	$62,796	$(82,896)

See accompanying notes to unaudited condensed consolidated financial statements.

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

	Accumulated Other Comprehensive Income (Loss)	Partners' Capital		
		General Partner	Limited Partners	Total
	(In thousands)			
Balance at December 31, 2011	$38,527	$23,902	$666,471	$728,900
Other comprehensive loss	(97,205)	—	—	(97,205)
Net income	—	6,456	153,545	160,001
Units repurchased for phantom unit grants	—	—	(2,110)	(2,110)
Issuance of phantom units	—	—	1,648	1,648
Amortization of vested phantom units	—	—	1,610	1,610
Proceeds from public offering of common units, net	—	—	146,558	146,558
Contributions from Calumet GP, LLC	—	3,122	—	3,122
Distributions to partners	—	(3,740)	(90,464)	(94,204)
Balance at September 30, 2012	$(58,678)	$29,740	$877,258	$848,320

See accompanying notes to unaudited condensed consolidated financial statements.

Table of Contents

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

	For the Nine Months Ended September 30,	
	2012	2011
	(In thousands)	
Operating activities		
Net income	$160,001	$16,164
Adjustments to reconcile net income to net cash provided by (used in) operating activities:		
Depreciation and amortization	63,828	43,644
Amortization of turnaround costs	10,315	8,288
Non-cash interest expense	4,409	2,363
Non-cash debt extinguishment costs	—	14,401
Provision for doubtful accounts	296	255
Unrealized loss on derivative instruments	11,337	23,876
Non-cash equity based compensation	5,108	3,298
Other non-cash activities	1,100	(1,468)
Changes in assets and liabilities:		
Accounts receivable	(32,370)	(44,714)
Inventories	33,678	(109,787)
Prepaid expenses and other current assets	(1,628)	(1,926)
Derivative activity	904	4,928
Turnaround costs	(14,141)	(8,849)
Deposits	(1,842)	(426)
Other assets	—	(197)
Accounts payable	26,845	32,158
Accrued interest payable	20,343	22,758
Accrued salaries, wages and benefits	2,327	2,917
Taxes payable	3,444	1,676
Other liabilities	2,851	(9,082)
Pension and postretirement benefit obligations	(7,365)	(836)
Net cash provided by (used in) operating activities	289,440	(559)
Investing activities		
Additions to property, plant and equipment	(36,735)	(30,667)
Proceeds from insurance recoveries — equipment	—	1,942
Cash paid for acquisitions, net of cash acquired	(379,048)	(441,626)
Proceeds from sale of property, plant and equipment	1,960	219
Net cash used in investing activities	(413,823)	(470,132)
Financing activities		
Proceeds from borrowings — revolving credit facility	1,147,778	1,152,898
Repayments of borrowings — revolving credit facility	(1,147,753)	(1,107,730)
Repayments of borrowings — term loan credit facility	—	(367,385)
Payments on capital lease obligations	(1,179)	(802)
Proceeds from public offerings of common units, net	146,558	281,870
Proceeds from senior notes offerings	270,187	586,000
Debt issuance costs	(7,542)	(23,140)

8

Table of Contents

Contributions from Calumet GP, LLC	3,122	6,011
Units repurchased for phantom unit grants	(2,110)	(620)
Distributions to partners	(94,204)	(56,382)
Net cash provided by financing activities	314,857	470,720
Net increase in cash and cash equivalents	190,474	29
Cash and cash equivalents at beginning of period	64	37
Cash and cash equivalents at end of period	$190,538	$66
Supplemental disclosure of noncash financing and investing activities		
Equipment acquired under capital lease	$5,771	$—

See accompanying notes to unaudited condensed consolidated financial statements.

CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(dollars in thousands)

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 September 30, 2012, the Company had 57,529,778 limited partner common units and 1,174,077 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 employees and the limited partnership reimburses the general partner for all expenses. The Company is engaged in the production and marketing of crude oil-based specialty lubricating oils, white mineral oils, solvents, petrolatums, asphalt, waxes and fuel and fuel related products including gasoline, diesel, jet fuel and heavy fuel oils. The Company owns facilities located in Shreveport, Louisiana ("Shreveport" and "TruSouth"); Superior, Wisconsin ("Superior"); Princeton, Louisiana ("Princeton"); Cotton Valley, Louisiana ("Cotton Valley"); Karns City, Pennsylvania ("Karns City"); Dickinson, Texas ("Dickinson"); Louisiana, Missouri ("Missouri") and Houston, 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 September 30, 2012 and for the three and nine months ended September 30, 2012 and 2011 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 and nine months ended September 30, 2012 are not necessarily indicative of the results that may be expected for the year ending December 31, 2012. These unaudited condensed consolidated financial statements should be read in conjunction with the Company's 2011 Annual Report.
2. New and Recently Adopted Accounting Pronouncements
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 Company is in the process of evaluating the impact of the adoption of ASU 2012-04 on its financial statements.
In July 2012, the FASB issued ASU No. 2012-02, Intangibles (Topic 350)—Testing Indefinite-Lived Intangible Assets for Impairment ("ASU 2012-02"). ASU 2012-02 permits an entity to first assess qualitative factors to determine if it is more likely than not that the fair value of an indefinite-lived intangible asset is more than its carrying amount. If based on its qualitative assessment an entity concludes it is more likely than not that the fair value of an indefinite-lived intangible asset exceeds its carrying amount, quantitative impairment testing is not required. However, if an entity concludes otherwise, quantitative impairment testing is required. ASU 2012-02 is effective for annual and interim impairment tests performed for fiscal years beginning after September 15, 2012, with early adoption permitted. The Company is in the process of evaluating the impact of the adoption of ASU 2012-02 on its financial statements.
In December 2011, the FASB issued ASU No. 2011-11, Balance Sheet (Topic 210)—Disclosures about Offsetting Assets and Liabilities ("ASU 2011-11"). ASU 2011-11 will require 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. ASU 2011-11 is effective for the first reporting period (including interim periods) beginning after January 1, 2013 and should be applied retrospectively for any period presented. The Company is in the process of evaluating the impact of the adoption of ASU 2011-11 on its financial statements.

In June 2011, the FASB issued ASU No. 2011-05, Comprehensive Income (Topic 220): Presentation of Comprehensive Income ("ASU 2011-05"), which amends current comprehensive income guidance. This accounting update eliminates the option to present the components of other comprehensive income (loss) as part of the statement of partners' capital. Instead, the Company must report comprehensive income in either a single continuous statement of comprehensive income (loss) which contains two sections, net income and other comprehensive income (loss), or in two separate but consecutive statements. In December 2011, the FASB issued ASU No. 2011-12, Comprehensive Income (Topic 220): Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05 ("ASU 2011-12), which indefinitely defers the requirement in ASU 2011-05 to present reclassification adjustments out of accumulated other comprehensive income (loss) by component in both the statement in which net income is presented and the statement in which other comprehensive income (loss) is presented. During the deferral period, the existing requirements in U.S. GAAP for the presentation of reclassification adjustments must continue to be followed. Amendments to ASU 2011-05, as superseded by ASU 2011-12, are effective for fiscal years (including interim periods) beginning after December 15, 2011 and are to be applied retrospectively, with early adoption permitted. The Company elected to present the components of comprehensive loss in two separate but consecutive financial statements, namely the unaudited condensed consolidated statements of operations and the unaudited condensed consolidated statements of comprehensive income (loss).

In May 2011, the FASB issued ASU No. 2011-04, Amendments to Achieve Common Fair Value Measurements and Disclosure Requirements in U.S. GAAP and IFRS ("ASU 2011-04"). ASU 2011-04 is intended to improve the comparability of fair value measurements presented and disclosed in financial statements prepared in accordance with U.S. GAAP and IFRS. The amendments are of two types: (i) those that clarify the FASB's intent about the application of existing fair value measurement and disclosure requirements and (ii) those that change a particular principle or requirement for measuring fair value or for disclosing information about fair value measurements. ASU 2011-04 is effective for the first reporting period (including interim periods) beginning after December 15, 2011. The adoption of ASU 2011-04 did not have a material impact on the Company's unaudited condensed consolidated financial statements.

3. Acquisitions

Superior Acquisition

On September 30, 2011, the Company completed the acquisition of the Superior, Wisconsin refinery and associated operating assets and inventories and related business of Murphy Oil Corporation ("Murphy Oil") for aggregate consideration of approximately $413,173 ("Superior Acquisition"). The Superior Acquisition was financed by a combination of (i) net proceeds of $193,538 from the Company's September 2011 public offering of common units (including the general partner's contribution but excluding the over-allotment option exercised), (ii) net proceeds of $180,296 from the Company's September 2011 private placement of 9 3/8% senior notes due May 1, 2019 and (iii) borrowings under the Company's revolving credit facility.

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

	Allocation of Purchase Price
Inventories	$183,602
Prepaid expenses and other current assets	5,845
Property, plant and equipment	239,478
Accrued salaries, wages and benefits	(775)
Pension and postretirement benefit obligations	(14,977)
Total purchase price	$413,173

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 ("Missouri Acquisition") for aggregate consideration of approximately $19,575. 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 have been included in the condensed consolidated balance sheets and results have been included in the unaudited condensed consolidated statements of operations since the date of acquisition. In connection with the Missouri Acquisition, during the three and nine months ended September 30, 2012, the Company incurred acquisition costs of approximately $0 and $505, respectively, which are reflected in general and administrative expenses in the unaudited condensed consolidated statements of operations.

Table of Contents

The Company recorded $1,478 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:

	Allocation of Purchase Price
Inventories	$2,775
Property, plant and equipment	9,955
Goodwill	1,478
Other intangible assets	5,367
Total purchase price	$19,575

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:

	Amount	Life (Years)
Customer relationships	$5,367	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 (“TruSouth Acquisition”) for aggregate consideration of approximately $26,827, net of cash acquired. 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 condensed consolidated balance sheets and results have been included in the unaudited condensed consolidated statements of operations since the date of acquisition. In connection with the TruSouth Acquisition, during the three and nine months ended September 30, 2012, the Company incurred acquisition costs of $0 and $179, respectively, which are reflected in general and administrative expenses in the unaudited condensed consolidated statements of operations.

The Company recorded $637 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 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:

	Allocation of Purchase Price
Accounts receivable	$4,972
Inventories	7,976
Prepaid expenses and other current assets	272
Property, plant and equipment	17,682
Goodwill	637
Other intangible assets	2,545
Accounts payable	(2,672)
Accrued salaries, wages and benefits	(151)
Other current liabilities	(918)
Long-term debt	(3,516)
Total purchase price, net of cash acquired	$26,827

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

Table of Contents

	Amount	Life (Years)
Customer relationships	$1,775	16
Tradenames	675	9
Non-competition agreements	95	2
Total	$2,545	
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, 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 for aggregate consideration of approximately $332,646, net of cash acquired (“Royal Purple Acquisition”). The Royal Purple Acquisition was financed with net proceeds of $262,645 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 markets, expands its geographic reach, increases its asset diversity and enhances its specialty products segment. The assets acquired have been included in the condensed consolidated balance sheets and results have been included in the unaudited condensed consolidated statements of operations since the date of acquisition. In connection with the Royal Purple Acquisition, during the three and nine months ended September 30, 2012, the Company incurred acquisition costs of approximately $271 and $396, respectively, which are reflected in general and administrative expenses in the unaudited condensed consolidated statements of operations.

The Company recorded $110,700 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 preliminary allocation of the aggregate purchase price to assets acquired and liabilities assumed is as follows:

	Allocation of Purchase Price
Accounts receivable	$15,030
Inventories	19,299
Prepaid expenses and other current assets	236
Deposits	13
Property, plant and equipment	10,580
Goodwill	110,700
Other intangible assets	183,398
Accounts payable	(3,804)
Accrued salaries, wages and benefits	(1,698)
Taxes payable	(198)
Other current liabilities	(910)
Total purchase price, net of cash acquired	$332,646

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

Table of Contents

	Amount	Life (Years)
Customer relationships	$118,683	20
Tradenames	14,790	Indefinite
Tradenames	5,746	10
Trade secrets	44,179	12
Total	$183,398	
Weighted average amortization period		18

Results of Sales and Earnings

The following financial information reflects the results of sales and operating income of the Superior, Missouri, TruSouth and Royal Purple Acquisitions that are included in the unaudited condensed consolidated statements of operations for the three and nine months ended September 30, 2012:

	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2012
Sales	$457,938	$1,143,096
Operating income	$77,640	$126,171

Pro Forma Financial Information

The following unaudited pro forma financial information reflects the unaudited condensed consolidated results of operations of the Company as if the Superior, Missouri, TruSouth and Royal Purple Acquisitions had taken place on January 1, 2011.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Sales	$1,179,818	$1,283,828	$3,496,575	$3,395,675
Net income	$42,416	$64,709	$151,306	$65,360
Limited partners’ interest net income per unit — basic and diluted	$0.69	$1.10	$2.50	$1.11

The Company’s historical financial information was adjusted to give effect to the pro forma events that were directly attributable to the Superior, Missouri, TruSouth and Royal Purple Acquisitions. This unaudited proforma 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 proforma events taken place on the dates indicated, or the future consolidated results of operations of the combined company.

For the three months ended September 30, 2012 , there were no adjustments recorded for pro forma information as actual results reflect all acquisition activity for the period.

For the three months ended September 30, 2011, the unaudited pro forma financial information reflects adjustments to increase interest expense as a result of the issuance of the 2019 Notes and 2020 Notes (defined below), amending and restating the revolving credit facility, additional borrowings under the revolving credit facility to fund portions of the Superior, Missouri and TruSouth Acquisitions and the repayment of borrowings under the prior term loan from the net proceeds of the 2019 Notes issued in April 2011. The unaudited pro forma financial information reflects adjustments to increase amortization expense by $5,625 as a result of recording Royal Purple's intangible assets.

For the nine months ended September 30, 2012, the unaudited pro forma financial information reflects adjustments to increase interest expense as a result of the issuance of the 2020 Notes (defined below). The unaudited pro forma financial information reflects adjustments to increase amortization expense by $10,864 as a result of recording Royal Purple's intangible assets.

For the nine months ended September 30, 2011, the unaudited pro forma financial information reflects adjustments to increase interest expense as a result of the issuance of the 2019 Notes and 2020 Notes (defined below), amending and restating the revolving credit facility, additional borrowings under the revolving credit facility to fund a portion of the Superior, Missouri

Table of Contents

and TruSouth Acquisitions and the repayment of borrowings under the prior term loan from the net proceeds of the 2019 Notes issued in April 2011. The unaudited pro forma financial information reflects adjustments to increase amortization expense by $16,087 as a result of recording Royal Purple's intangible assets.

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 Company uses the last-in, first-out (LIFO) method of valuing inventory. 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. Inventories consist of the following:

	September 30, 2012	December 31, 2011
Raw materials	$83,041	$105,802
Work in process	108,169	91,763
Finished goods	302,902	300,175
	$494,112	$497,740

The replacement cost of these inventories, based on current market values, would have been $52,175 and $87,635 higher as of September 30, 2012 and December 31, 2011, respectively.

5. Goodwill and Intangible Assets

The Company has recorded $48,335 of goodwill as a result of the acquisition of Penreco in 2008, all of which is recorded within the Company's specialty products segment. During 2012, the Company has recorded $1,478 of goodwill as a result of the Missouri Acquisition, $637 of goodwill as a result of the TruSouth Acquisition and $110,700 of goodwill as a result of the Royal Purple Acquisition, all of which is recorded within the Company's specialty products segment.

Other intangible assets consist of the following:

	Weighted Average Life (Years)	September 30, 2012		December 31, 2011	
		Gross Amount	Accumulated Amortization	Gross Amount	Accumulated Amortization
Customer relationships	20	$154,307	$(18,648)	$28,482	$(12,936)
Supplier agreements	4	21,519	(21,120)	21,519	(19,926)
Tradenames - Royal Purple Retail	Indefinite	14,790	—	—	—
Tradenames	9	6,421	(294)	—	—
Trade secrets	12	44,179	(1,558)	—	—
Patents	12	1,573	(1,075)	1,573	(966)
Noncompetition agreements	5	5,827	(5,381)	5,732	(4,182)
Distributor agreements	3	2,019	(2,019)	2,019	(2,019)
Royalty agreements	19	4,499	(1,287)	4,499	(1,120)
	16	$255,134	$(51,382)	$63,824	$(41,149)

Intangible assets associated with supplier agreements, tradenames, trade secrets, patents, noncompetition agreements, distributor agreements and royalty agreements are being amortized to properly match expense with the discounted estimated future cash flows over the terms of the related agreements. Agreements with terms allowing for the potential extension of such agreements

Table of Contents

are being amortized based on the initial term only. Intangible assets associated with customer relationships are being amortized using discounted estimated future cash flows based upon assumed rates of annual customer attrition. For the three months ended September 30, 2012 and 2011, the Company recorded amortization expense of intangible assets of $6,665 and $1,747, respectively. For the nine months ended September 30, 2012 and 2011, the Company recorded amortization expense of intangible assets of $10,233 and $5,243, respectively.

The Company estimates that amortization of intangible assets for the next five years will be as follows:

Year	Amortization Amount
Remainder of 2012	$6,669
2013	$25,401
2014	$24,297
2015	$22,165
2016	$20,217
2017	$17,669

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”), the Louisiana Department of Environmental Quality (“LDEQ”), the Wisconsin Department of Natural Resources (“WDNR”), 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 can 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 connection with the Montana Acquisition (see Note 15 below), the Company became a party to an existing 2002 Refinery Initiative consent decree (“Montana Consent Decree”) with the EPA and State of Montana. The material obligations imposed by the Montana Consent Decree have been completed. Periodic reporting is the primary current obligation under this 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 such contamination is subject to the indemnification of Montana Refining Company, Inc. by Holly Corporation ("Holly") for pre-existing conditions. The Company is indemnified by Holly under the asset purchase agreement between Holly and Connacher, which the Company became a party to by virtue of the share purchase agreement between the Company and Connacher. Holly is responsible for existing environmental conditions at the Montana refinery, and has been reimbursing Connacher for remedial actions subject to the indemnification.

In connection with the Superior Acquisition, the Company became a party to an existing consent decree (“Consent Decree”) with the EPA and the WDNR that applies, in part, to its Superior refinery. Under the 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 $4,300 to make known equipment upgrades and conduct other discrete tasks in compliance with the Consent Decree. Failure to perform required tasks under the 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 would result in the Company incurring additional costs, which could be substantial. For the three and nine months ended September 30, 2012, the Company incurred approximately $646 and $2,075, 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 Company's 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 is currently awaiting an informal conference with the EPA. The Company does not believe that the resolution of these allegations will have a material adverse effect on the Company's financial results or operations.

In addition, the Company is indemnified by Murphy Oil for specified environmental liabilities including: (i) certain obligations arising out of the Consent Decree (including payment of a civil penalty required under the Consent Decree), (ii) certain liabilities arising in connection with Murphy Oil's transport of certain wastes and other materials to specified offsite real properties for disposal or recycling prior to the Superior Acquisition and (iii) certain liabilities for certain third party actions, suits or proceedings alleging exposure, prior to the Superior Acquisition, of an individual to wastes or other materials at the specified on-site real property, which wastes or other materials were spilled, released, emitted or discharged by Murphy Oil. The Company is also indemnified by Murphy Oil for two years following the Superior Acquisition for liabilities arising from breaches of certain environmental representations and warranties made by Murphy Oil, subject to a maximum liability of $22,000, for which the Company is required to contribute up to the first $6,600.

On December 23, 2010, the Company entered into a settlement agreement with the 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. The Company made a $1,000 payment to the LDEQ and 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 and nine months ended September 30, 2012, the Company incurred approximately $50 and $2,222, respectively, of expenditures and estimates additional expenditures of approximately $4,000 to $8,000 of capital expenditures and expenditures related to additional personnel and environmental studies over the next four years as a result of the implementation of these requirements. This settlement agreement also fully settles the alleged environmental and permit violations at the Company's Shreveport, Cotton Valley and Princeton refineries and stipulates that no further civil penalties over alleged past violations at those refineries will be pursued by the LDEQ. The required investments are expected to include projects resulting in (i) nitrogen oxide and sulfur dioxide emission reductions from heaters and boilers and the application of New Source Performance Standards for sulfur recovery plants and flaring devices, (ii) control of incidents related to acid gas flaring, tail gas and hydrocarbon flaring, (iii) electrical reliability improvements to reduce flaring, (iv) flare refurbishment at the Shreveport refinery, (v) enhancement of the Benzene Waste National Emissions Standards for Hazardous Air Pollutants programs and the Leak Detection and Repair programs at the Company's Shreveport, Princeton and Cotton Valley refineries and (vi) Title V audits and targeted audits of certain regulatory compliance programs. During negotiations with the LDEQ, the Company voluntarily initiated projects for certain of these requirements prior to completing the Global Settlement with the LDEQ, and currently anticipates completion of these projects over the next four years. These capital investment requirements will be incorporated into the Company's annual capital expenditures budget and the Company does not expect any additional capital expenditures as a result of the required audits or required operational changes included in the Global Settlement to have a material adverse effect on the Company's financial results or operations. The terms of this settlement agreement were deemed final and effective on January 31, 2012 upon the concurrence of the Louisiana Attorney General.

In addition, new laws and regulations, new interpretations of existing laws and regulations, increased governmental enforcement or other developments could require us 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 June 1, 2012, the EPA issued 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 the Company's refinery operations.

Voluntary remediation of subsurface contamination is in process at each 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

Table of Contents

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. The Company incurred approximately $129 and $142 of such capital expenditures at its Cotton Valley refinery, respectively, during the three and nine months ended September 30, 2012. The Company incurred approximately $5 and $266, respectively, of such capital expenditures at its Cotton Valley refinery during the three and nine months ended September 30, 2011.
The Company is indemnified by Shell Oil Company, as successor to Pennzoil-Quaker State Company and Atlas Processing Company, for specified environmental liabilities arising from the operations of the Shreveport refinery prior to the Company's acquisition of the facility. The indemnity is unlimited in amount and duration, but requires the Company to contribute up to $1,000 of the first $5,000 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 has implemented an internal program of inspection designed to monitor and enforce compliance with worker safety requirements 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.

The Company has completed studies to assess the adequacy of its process safety management practices at its Shreveport refinery with respect to certain consensus codes and standards. During the three and nine months ended September 30, 2012, the Company incurred approximately $195 and $506, respectively, of capital expenditures and expects to incur between $1,000 and $4,000 of capital expenditures during the remainder of 2012 and 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 process safety management 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 $208. The Company has contested the Cotton Valley Citation and associated penalties 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 Superior collective bargaining agreement was ratified on August 10, 2012 and will expire on June 30, 2017. The Missouri collective bargaining agreement was ratified on May 1, 2012 and will expire on April 30, 2014.

Standby Letters of Credit

The Company has agreements with various financial institutions for standby letters of credit which have been issued to domestic vendors. As of September 30, 2012 and December 31, 2011, the Company had outstanding standby letters of credit of $180,688 and $230,040, respectively, under its senior secured revolving credit facility (the "revolving credit facility"). Refer to Note 7 for additional information regarding the revolving credit facility. The maximum amount of letters of credit the Company could issue at September 30, 2012 and December 31, 2011 under its revolving credit facility is subject to borrowing base limitations, with a maximum letter of credit sublimit equal to $680,000, which is the greater of (i) $400,000 and (ii) 80% of revolver commitments ($850,000 at September 30, 2012 and December 31, 2011) in effect.

As of September 30, 2012 and December 31, 2011, the Company had availability to issue letters of credit of $477,752 and $340,715, respectively, under its revolving credit facility. As discussed in Note 7, as of September 30, 2012 and December 31, 2011 the outstanding standby letters of credit issued under the revolving credit facility included a $25,000 letter of credit issued to a hedging counterparty to support a portion of its fuel products hedging program.

Table of Contents

7. Long-Term Debt

Long-term debt consisted of the following:

	September 30, 2012	December 31, 2011
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 4.50% for the nine months ended September 30, 2012	$25	$—
Borrowings under 2019 Notes, interest at a fixed rate of 9.375%, interest payments semiannually, borrowings due May 2019, effective interest rate of 9.90% for the nine months ended September 30, 2012	600,000	600,000
Borrowings under 2020 Notes, interest at a fixed rate of 9.625%, interest payments semiannually, borrowings due August 2020, effective interest rate of 9.98% for the nine months ended September 30, 2012	275,000	—
Capital lease obligations, at various interest rates, interest and principal payments monthly through January 2027	5,720	786
Less unamortized discounts	(17,449)	(13,696)
Total long-term debt	863,296	587,090
Less current portion of long-term debt	783	551
	$862,513	$586,539

9 5/8% Senior Notes

On June 29, 2012, in connection with the Royal Purple Acquisition, the Company issued and sold $275,000 in aggregate principal amount of 9 5/8% of senior notes due August 1, 2020 (the “2020 Notes”) in a private placement pursuant to Rule 144A under 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 $262,645, 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 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.

At any time prior to August 1, 2015, the Company may on any one or more occasions redeem up to 35% of the aggregate principal amount of the 2020 Notes with the net proceeds of a public or private equity offering at a redemption price of 109.625% of the principal amount, plus any accrued and unpaid interest to the date of redemption, provided that: (1) at least 65% of the aggregate principal amount of 2020 Notes issued remains outstanding immediately after the occurrence of such redemption and (2) the redemption occurs within 120 days of the date of the closing of such public or private equity offering.

On and after August 1, 2016, the Company may on any one or more occasions redeem all or a part of the 2020 Notes at the redemption prices (expressed as percentages of principal amount) set forth below, plus any accrued and unpaid interest to the applicable redemption date on such 2020 Notes, if redeemed during the twelve-month period beginning on August 1 of the years indicated below:

Year	Percentage

2016	104.813	%
2017	102.406	%
2018 and at any time thereafter	100.000	%

19

Table of Contents

Prior to August 1, 2016, the Company may on any one or more occasions redeem all or part of the 2020 Notes at a redemption price equal to the sum of: (1) the principal amount thereof, plus (2) a make-whole premium (as set forth in the indenture governing the 2020 Notes) at the redemption date, plus any accrued and unpaid interest to the applicable redemption date.

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.

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.

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.

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 $400,000 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 Rule 144A under 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 $388,999 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 $200,000 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 Rule 144A 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 received proceeds of $180,296 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 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.

Table of Contents

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.

Amended and Restated Senior Secured Revolving Credit Facility

The Company has an $850,000 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 1, 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 September 30, 2012, the margin was 125 basis points for prime and 250 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 September 30, 2012 under the revolving credit facility was $658,465. As of September 30, 2012, the Company had $25 in outstanding borrowings under the revolving credit facility, leaving $477,752 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) $46,364, (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 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.

Capital Lease Obligations

In connection with the TruSouth Acquisition, the Company recorded $5,771 of capital leases for a building and equipment.

Table of Contents

Maturities of Long-Term Debt

As of September 30, 2012, maturities of the Company's long-term debt are as follows:

Year	Maturity
2012	$207
2013	771
2014	423
2015	303
2016	354
Thereafter	878,687
Total	$880,745

8. Derivatives

The Company utilizes derivative instruments to minimize its price risk and volatility of cash flows associated with the purchase of crude oil and natural gas, the sale of fuel products and interest payments. The Company employs various hedging strategies, which are further discussed below. 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 Company recorded the following derivative assets and liabilities at their fair values as of September 30, 2012 and December 31, 2011:

	Derivative Assets		Derivative Liabilities	
	September 30, 2012	December 31, 2011	September 30, 2012	December 31, 2011
Derivative instruments designated as hedges:				
Fuel products segment:				
Crude oil swaps	$—	$83,919	$(21,235)	$56,041
Gasoline swaps	—	(20,605)	67	(1,596)
Diesel swaps	—	(4,561)	(33,256)	(22,586)
Jet fuel swaps	—	1,077	(28,786)	(72,537)
Total derivative instruments designated as hedges	—	59,830	(83,210)	(40,678)
Derivative instruments not designated as hedges:				
Fuel products segment:				
Crude oil swaps	—	—	9,120	—
Gasoline swaps	—	—	(16,062)	—
Diesel swaps	—	—	(6,733)	—
Jet fuel swaps	—	—	—	—
Specialty products segment:				
Crude oil swaps	—	—	1,628	—
Natural gas swaps (1)	—	(1,328)	(545)	(1,892)
Interest rate swaps: (2)	—	—	—	(1,011)
	—	(1,328)	(12,592)	(2,903)

Total derivative instruments not designated as hedges				
Total derivative instruments	$—	$58,502	$(95,802)	$(43,581)

22

Table of Contents

(1) The Company enters into natural gas swaps to economically hedge 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.

(2) The Company refinanced a significant majority of its long-term debt in April 2011 and, as a result, all of its interest rate swaps that were designated as cash flow hedges for the interest payments under the previous term loan facility are no longer designated as cash flow hedges.

The Company accounts for certain derivatives hedging purchases of crude oil, 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. At times, the Company may enter into crude oil or fuel product basis swaps to more effectively hedge its crude oil purchases. 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 the fourth quarter of 2012 and 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 (loss) on derivative instruments in the unaudited condensed consolidated statements of operations. Unrealized gains and losses related to discontinued cash flow hedges that were previously accumulated in accumulated other comprehensive income (loss) will remain in accumulated other comprehensive income (loss) until the underlying transaction is reflected in earnings, unless it is probable that the hedged forecasted transaction will not occur, at which time, associated deferred amounts in accumulated other comprehensive income (loss) are immediately recognized in unrealized gain (loss) on derivative instruments.

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 $4,767 and derivative gains $49,661 in realized gain (loss) on derivative instruments, respectively, in the unaudited condensed consolidated statements of operations for the three and nine months ended September 30, 2012. The discontinuance of hedge accounting on these derivative instruments caused the Company to recognize derivative losses of $34,975 and $6,848 in unrealized loss on derivative instruments, respectively, in the unaudited condensed consolidated statements of operations for the three and nine months ended September 30, 2012.

The amount reclassified from accumulated other comprehensive income (loss) into earnings, as a result of the discontinuance of hedge accounting for certain jet fuel products derivative instruments because it was no longer probable that the original forecasted transaction would occur by the end of the originally specified time period, has caused the Company to recognize derivative losses of $652 and $1,719 in realized gain (loss) on derivative instruments, respectively, in the unaudited condensed consolidated statements of operations for the three and nine months ended September 30, 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 (loss) 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, which has the potential for the future loss of hedge accounting, determined on a derivative by derivative basis or in the aggregate for a specific commodity. Ineffectiveness has resulted, and the loss of hedge accounting has

Table of Contents

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, September 30, 2012 and 2011 related to its derivative instruments that were designated as cash flow hedges:

	Amount of Gain (Loss) Recognized in Accumulated Other Comprehensive Income (Loss) on Derivatives (Effective Portion)		Amount of (Gain) Loss Reclassified from Accumulated Other Comprehensive Income (Loss) into Net Income (Effective Portion)			Amount of Gain (Loss) Recognized in Net Income on Derivatives (Ineffective Portion)		
	Three Months Ended September 30,		Location of (Gain) Loss	Three Months Ended September 30,		Location of Gain (Loss)	Three Months Ended September 30,	
Type of Derivative	2012	2011		2012	2011		2012	2011
Fuel products segment:								
Crude oil swaps	$13,042	$(171,581)	Cost of sales	$(7,996)	$(25,411)	Unrealized/ Realized	$34,078	$(22,072)
Gasoline swaps	8,880	5,883	Sales	—	4,493	Unrealized/ Realized	(23,037)	(19)
Diesel swaps	(49,261)	46,413	Sales	29,164	18,887	Unrealized/ Realized	(1,156)	(252)
Jet fuel swaps	(56,052)	81,523	Sales	20,408	37,745	Unrealized/ Realized	(4,577)	(1,793)
Jet fuel collars	—	—	Sales	—	—	Unrealized/ Realized	—	—
Specialty products segment:								
Crude oil swaps	—	—	Cost of sales	190	(1,364)	Unrealized/ Realized	—	—
Natural gas swaps	—	—	Cost of sales	—	—	Unrealized/ Realized	—	—
Interest rate swaps:	—	—	Interest expense	—	—	Unrealized/ Realized	—	—
Total	$(83,391)	$(37,762)		$41,766	$34,350		$5,308	$(24,136)

The Company recorded the following gains (losses) in its unaudited condensed consolidated statements of operations and its unaudited condensed consolidated statements of partners' capital for the three months ended September 30, 2012 and 2011 related to its derivative instruments not designated as cash flow hedges.

	Amount of Gain (Loss) Recognized in	Amount of Gain (Loss) Recognized in

Type of Derivative	Realized Gain (Loss) on Derivative Instruments Three Months Ended September 30, 2012	2011	Unrealized Loss on Derivative Instruments Three Months Ended September 30, 2012	2011
Fuel products segment:				
Crude oil swaps	$(8,854)	$—	$40,165	$—
Gasoline swaps	2,451	—	(40,966)	—
Diesel swaps	2,860	—	(34,174)	—
Jet fuel swaps	(651)	—	480	—
Jet fuel collars	—	—	—	(1)
Specialty products segment:				
Crude oil swaps	—	—	1,044	—
Natural gas swaps	(1,467)	—	1,540	—
Interest rate swaps:	(137)	(655)	144	643
Total	$(5,798)	$(655)	$(31,767)	$642

Table of Contents

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 nine months ended, September 30, 2012 and 2011 related to its derivative instruments that were designated as cash flow hedges:

Type of Derivative	Amount of Gain (Loss) Recognized in Accumulated Other Comprehensive Income (Loss) on Derivatives (Effective Portion) Nine Months Ended September 30, 2012	2011	Location of (Gain) Loss	Amount of (Gain) Loss Reclassified from Accumulated Other Comprehensive Income (Loss) into Net Income (Effective Portion) Nine Months Ended September 30, 2012	2011	Location of Gain (Loss)	Amount of Gain (Loss) Recognized in Net Income on Derivatives (Ineffective Portion) Nine Months Ended September 30, 2012	2011
Fuel products segment:								
Crude oil swaps	$(85,858)	$(110,393)	Cost of sales	$(42,606)	$(86,510)	Unrealized/ Realized	$84,004	$(22,569)
Gasoline swaps	(31,285)	(11,853)	Sales	39,204	23,308	Unrealized/ Realized	(38,355)	(1,358)
Diesel swaps	(70,692)	(22,379)	Sales	52,005	62,074	Unrealized/ Realized	(2,996)	(790)
Jet fuel swaps	(48,444)	(37,891)	Sales	89,018	80,419	Unrealized/ Realized	(2,686)	(3,397)
Jet fuel collars	—	—	Sales	—	—	Unrealized/ Realized	—	—
Specialty products segment:								
Crude oil swaps	—	—	Cost of sales	176	1,301	Unrealized/ Realized	—	—
Natural gas swaps	—	—	Cost of sales	—	—	Unrealized/ Realized	—	—
Interest rate swaps:	—	1,979	Interest expense	—	702	Unrealized/ Realized	—	—
Total	$(236,279)	$(180,537)		$137,797	$81,294		$39,967	$(28,114)

The Company recorded the following gains (losses) in its unaudited condensed consolidated statements of operations and its unaudited condensed consolidated statements of partners' capital for the nine months ended September 30, 2012 and 2011 related to its derivative instruments not designated as cash flow hedges.

Type of Derivative	Amount of Gain (Loss) Recognized in Realized Gain (Loss) on Derivative Instruments Nine Months Ended September 30, 2012	2011	Amount of Gain (Loss) Recognized in Unrealized Loss on Derivative Instruments Nine Months Ended September 30, 2012	2011
Fuel products segment:				

Crude oil swaps	$(16,207)	$—	$(40,000)	$—
Gasoline swaps	13,842	—	(1,149)	—
Diesel swaps	8,044	—	6,700	—
Jet fuel swaps	(1,719)	—	—	—
Jet fuel collars	—	(562)	—	542
Specialty products segment:				
Crude oil swaps	—	932	1,628	(662)
Natural gas swaps	(4,917)	—	2,675	—
Interest rate swaps:	(726)	(1,407)	1,011	(403)
Total	$(1,683)	$(1,037)	$(29,135)	$(523)

The cash flow impact of the Company’s derivative activities is classified primarily as a component of net income (loss) in the operating activities section in the unaudited condensed consolidated statements of cash flows.

Table of Contents

The Company is exposed to credit risk in the event of nonperformance by its counterparties on these derivative transactions. The Company does not expect nonperformance on any derivative instruments, however, no assurances can be provided. The Company's credit exposure related to these derivative instruments is represented by the fair value of contracts reported as derivative assets. As of September 30, 2012, the Company did not have any counterparties, in which derivatives held were net assets. As of December 31, 2011, the Company had three counterparties, in which the derivatives held were net assets, totaling $58,502. 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 September 30, 2012 or December 31, 2011. The Company's contracts with these counterparties allow for netting of derivative instruments executed under each contract. Collateral received from counterparties is reported in other current liabilities, and collateral held by counterparties is reported in deposits, on the Company's condensed consolidated balance sheets and is not netted against derivative assets or liabilities. As of September 30, 2012 and December 31, 2011, the Company had provided its counterparties with no collateral except for a $25,000 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 September 30, 2012 and December 31, 2011, there was a net liability of $9,663 and net asset of $3,561, 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 $51,388 as of September 30, 2012. The effective portion of the cash flow hedges classified in accumulated other comprehensive income was $47,094 as of December 31, 2011. Absent a change in the fair market value of the underlying transactions, the following other comprehensive income (loss) at September 30, 2012 will be reclassified to earnings by December 31, 2015 with balances being recognized as follows:

Year	Accumulated Other Comprehensive Loss	
2012	$ (13,367	)
2013	(22,515	)
2014	(13,585	)
2015	(1,921	)
Total	$ (51,388	)

Based on fair values as of September 30, 2012, the Company expects to reclassify $34,049 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 and Collar Contracts — Specialty Products Segment

The Company is exposed to fluctuations in the price of crude oil, its principal raw material. Historically, the Company has utilized combinations of options and swaps to manage crude oil price risk and volatility of cash flows in its specialty

Table of Contents

products segment. These derivatives may be designated as cash flow hedges of the future purchase of crude oil if they meet the hedge criteria. The company's general policy is to enter into crude oil derivative contracts that mitigate the Company's exposure to price risk associated with crude oil purchases related to specialty products production (for up to 70% of expected purchases). The Company may execute derivative contracts for up to two years forward. As of September 30, 2012, the Company purchased a crude oil derivative swap for 200,000 bbls in the second quarter of 2012 related to future crude oil purchases in its specialty segment, which is not designated as a cash flow hedge. The Company has subsequently sold a crude oil derivative swap in the third quarter of 2012, and the net impact of these two trades is a net gain of $1,044 and $1,628 that has been recorded to unrealized gain, respectively, in the unaudited condensed consolidated statements of operations for the three and nine months ended September 30, 2012. This gain will be realized in January 2013 and will be recorded to realized gain (loss) in the unaudited condensed consolidated statement of operations.

At December 31, 2011, the Company did not have any crude oil derivatives related to future crude oil purchases in its specialty products segment.

Natural Gas Swap Contracts

Natural gas purchases comprise a significant component of the Company's cost of sales; therefore, changes in the price of natural gas also significantly affect its profitability and cash flows. The Company utilizes swap contracts to manage natural gas price risk and volatility of cash flows. The Company's policy is generally to enter into natural gas derivative contracts to hedge no more than 75% of its anticipated natural gas requirement for a period no greater than three years forward. At September 30, 2012, the Company had the following natural gas derivatives related to natural gas purchases in its specialty products segment, none of which were designated as cash flow hedges.

Natural Gas Swap Contracts by Expiration Dates	MMBtu	$/MMBtu
Fourth Quarter 2012	600,000	$4.08
Totals	600,000	
Average price		$4.08

At December 31, 2011, the Company had the following natural gas derivatives related to natural gas purchases in its specialty products segment, none of which were designated as cash flow hedges.

Natural Gas Swap Contracts by Expiration Dates	MMBtu	$/MMBtu
First Quarter 2012	1,200,000	$3.90
Second Quarter 2012	1,200,000	3.93
Third Quarter 2012	1,200,000	4.03
Fourth Quarter 2012	600,000	4.08
Totals	4,200,000	
Average price		$3.97

Crude Oil Contracts — Fuel Products Segment

Crude Oil Swap Contracts

The Company is exposed to fluctuations in the price of crude oil, its principal raw material. The Company utilizes swap contracts to manage crude oil price risk and volatility of cash flows in its fuel products segment. The Company's policy is generally to enter into crude oil swap contracts for a period no greater than five years forward and for no more than 75% of crude oil purchases used in fuels production. At September 30, 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.

Table of Contents

Crude Oil Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Swap ($/Bbl)
Fourth Quarter 2012	1,242,000	13,500	$90.50
Calendar Year 2013	5,784,000	15,847	98.85
Calendar Year 2014	4,195,000	11,493	89.31
Calendar Year 2015	3,467,500	9,500	90.44
Totals	14,688,500		
Average price			$93.43

At September 30, 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)
Fourth Quarter 2012	1,380,000	15,000	$83.35
Calendar Year 2013	1,821,000	4,989	98.72
Totals	3,201,000		
Average price			$92.09

At December 31, 2011, 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 2012	2,866,500	31,500	$85.34
Second Quarter 2012	2,775,500	30,500	84.83
Third Quarter 2012	2,852,000	31,000	84.83
Fourth Quarter 2012	2,622,000	28,500	86.73
Calendar Year 2013	4,420,000	12,110	97.93
Calendar Year 2014	1,000,000	2,740	90.55
Totals	16,536,000		
Average price			$89.07

Crude Oil Basis Swap Contracts

In April and July 2012, 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. At September 30, 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.

Crude Oil Basis Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Differential to NYMEX WTI ($/Bbl)
Fourth Quarter 2012	184,000	2,000	$(23.50)
Calendar Year 2013	730,000	2,000	(23.75)
Totals	914,000		
Average price			$(23.70)

At December 31, 2011, the Company had no derivatives related to crude oil basis swaps in its fuel products segment.

Fuel Products Swap Contracts

The Company is exposed to fluctuations in the prices of gasoline, diesel and jet fuel. The Company utilizes swap contracts to manage diesel, gasoline and jet fuel price risk and volatility of cash flows in its fuel products segment. The

28

Table of Contents

Company's policy is generally to enter into diesel, jet fuel and gasoline swap contracts for a period no longer than five years forward and for no more than 75% of forecasted fuel sales.

Diesel Swap Contracts

At September 30, 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)
Fourth Quarter 2012	506,000	5,500	$ 105.41
Calendar Year 2013	1,926,000	5,277	121.78
Calendar Year 2014	2,920,000	8,000	114.83
Calendar Year 2015	3,467,500	9,500	116.65
Totals	8,819,500		
Average price			$ 116.52

At September 30, 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)
Fourth Quarter 2012	460,000	5,000	$ 115.27
Calendar Year 2013	1,456,000	3,989	127.20
Totals	1,916,000		
Average price			$ 124.34

At December 31, 2011, 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)
First Quarter 2012	546,000	6,000	$ 118.07
Second Quarter 2012	819,000	9,000	110.09
Third Quarter 2012	1,150,000	12,500	105.48
Fourth Quarter 2012	966,000	10,500	110.11
Calendar Year 2013	1,831,000	5,016	123.20
Totals	5,312,000		
Average price			$ 114.44

Jet Fuel Swap Contracts

At September 30, 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)
Fourth Quarter 2012	736,000	8,000	$ 104.79
Calendar Year 2013	2,498,000	6,844	127.09
Calendar Year 2014	1,275,000	3,493	116.64
Totals	4,509,000		
Average price			$ 120.50

Table of Contents

At December 31, 2011, 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 2012	1,274,000	14,000	$97.97
Second Quarter 2012	1,046,500	11,500	98.47
Third Quarter 2012	782,000	8,500	99.78
Fourth Quarter 2012	736,000	8,000	104.79
Calendar Year 2013	2,044,000	5,600	125.13
Calendar Year 2014	1,000,000	2,740	115.56
Totals	6,882,500		
Average price			$109.60

Gasoline Swap Contracts

At September 30, 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)
Calendar Year 2013	1,360,000	3,726	$114.84
Totals	1,360,000		
Average price			$114.84

At September 30, 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)
Fourth Quarter 2012	920,000	10,000	$102.48
Calendar Year 2013	365,000	1,000	105.50
Totals	1,285,000		
Average price			$103.33

At December 31, 2011, 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 2012	1,046,500	11,500	$100.72
Second Quarter 2012	910,000	10,000	102.48
Third Quarter 2012	920,000	10,000	102.48
Fourth Quarter 2012	920,000	10,000	102.48
Calendar Year 2013	545,000	1,493	107.11
Totals	4,341,500		
Average price			$102.63

Interest Rate Swap Contracts

The Company’s profitability and cash flows are affected by changes in interest rates, specifically LIBOR and prime rates. The primary purpose of the Company’s interest rate risk management activities is to hedge its exposure to changes in interest rates. Historically, the Company’s policy has been to enter into interest rate swap agreements to hedge up to 75% of its interest rate risk related to variable rate debt. With the issuances of the 2019 Notes and 2020 Notes, which constitute fixed rate debt, the

Table of Contents

Company does not expect to enter into hedges to fix its interest rates. At September 30, 2012, the Company did not have any interest rate swap contracts.

9. Fair Value Measurements

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

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

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

Recurring Fair Value Measurements

Derivative Assets and Liabilities

Derivative instruments are reported in the accompanying unaudited condensed consolidated financial statements at fair value. The Company's derivative instruments consist of over-the-counter ("OTC") contracts, which are not traded on a public exchange. Substantially all of the Company's derivative instruments are with counterparties that have long-term credit ratings of at least Baa2 and 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, gasoline, diesel, jet fuel and natural gas 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 September 30, 2012, the Company's liability was reduced by approximately $2,469. As a result of applying the CDS at December 31, 2011, the Company's asset was reduced by $1,297 and the liability was reduced by approximately $165.

Based on the use of various unobservable inputs, principally non-performance risk and unobservable inputs in forward years for crude oil, gasoline, jet fuel, diesel and natural gas, 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 and

(iii) a commingled fund. The mutual funds are publicly traded and market prices are readily available; thus, these investments are categorized as

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Table of Contents

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.

Hierarchy of Recurring Fair Value Measurements

The Company's recurring assets and liabilities measured at fair value at September 30, 2012 and December 31, 2011 were as follows:

	September 30, 2012				December 31, 2011			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Cash and cash equivalents	$190,538	$—	$—	$190,538	$64	$—	$—	$64
Derivative assets:								
Crude oil swaps	—	—	—	—	—	—	83,919	83,919
Gasoline swaps	—	—	—	—	—	—	(20,605)	(20,605)
Diesel swaps	—	—	—	—	—	—	(4,561)	(4,561)
Jet fuel swaps	—	—	—	—	—	—	1,077	1,077
Natural gas swaps	—	—	—	—	—	—	(1,328)	(1,328)
Total derivative assets	—	—	—	—	—	—	58,502	58,502
Pension plan investments	36,154	2,706	—	38,860	33,580	2,462	—	36,042
Total recurring assets at fair value	$226,692	$2,706	$—	$229,398	$33,644	$2,462	$58,502	$94,608
Liabilities:								
Derivative liabilities:								
Crude oil swaps	$—	$—	$(10,487)	(10,487)	$—	$—	$56,041	$56,041
Gasoline swaps	—	—	(15,995)	(15,995)	—	—	(1,596)	(1,596)
Diesel swaps	—	—	(39,989)	(39,989)	—	—	(22,586)	(22,586)
Jet fuel swaps	—	—	(28,786)	(28,786)	—	—	(72,537)	(72,537)
Natural gas swaps	—	—	(545)	(545)	—	—	(1,892)	(1,892)
Interest rate swaps	—	—	—	—	—	—	(1,011)	(1,011)
Total derivative liabilities	—	—	(95,802)	(95,802)	—	—	(43,581)	(43,581)
Total recurring liabilities at fair value	$—	$—	$(95,802)	$(95,802)	$—	$—	$(43,581)	$(43,581)

The table below sets forth a summary of net changes in fair value of the Company's Level 3 financial assets and liabilities for the nine months ended September 30, 2012 and 2011:

	Nine Months Ended September 30,	
	2012	2011
Fair value at January 1,	$14,921	$(32,814)
Realized (gain) loss on derivative instruments	(20,486)	5,798
Unrealized loss on derivative instruments	(11,337)	(23,876)
Change in fair value of cash flow hedges	(236,279)	(180,537)
Settlements	157,379	70,568
Transfers in (out) of Level 3	—	—
Fair value at September 30,	$(95,802)	$(160,861)

Total loss included in net income attributable to changes in unrealized loss relating to financial assets and liabilities held as of September 30,	$(11,337)	$(23,876)

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 financial statements of operations in the period that the hedged cash flow occurs. Any "ineffectiveness" associated with these derivative instruments are 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 and Royal Purple 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 and Cash Equivalents

The carrying values of cash and cash equivalents are considered to be representative of their respective fair values, due to the short maturity of these instruments.

Debt

The estimated fair value of long-term debt at September 30, 2012 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, 2011 consists primarily of the 2019 Notes. The fair value of the Company's 2019 Notes and 2020 Notes were based upon using quoted market prices in an active market and are classified as Level 1. 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 value as determined by discounted cash flows and are classified as Level 3.

The Company's carrying and estimated fair value of the Company's financial instruments, carried at adjusted historical cost, at September 30, 2012 and December 31, 2011 were as follows:

	September 30, 2012		December 31, 2011	
	Fair Value	Carrying Value	Fair Value	Carrying Value
Financial Instrument:				
2019 Notes	$647,495	$587,265	$591,750	$586,304

2020 Notes	$298,031	$270,286	$—	$—
Revolving credit facility	$25	$25	$—	$—
Capital lease and other obligations	$5,720	$5,720	$786	$786

Table of Contents

10. Partners' Capital

On May 8, 2012, the Company completed a public offering of its common units in which it sold 6,000,000 common units to the underwriters of the offering at a price to the public of $25.50 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 $146,558 and were used to repay borrowings under its revolving credit facility. Underwriting discounts totaled $6,180. The Company's general partner contributed $3,122 to maintain its 2% general partner interest.

The Company's distribution policy is defined in its partnership agreement. For the three months ended September 30, 2012 and 2011, the Company made distributions of $35,890 and $20,124, respectively, to its partners. For the nine months ended September 30, 2012 and 2011, the Company made distributions of $94,204 and $56,382, respectively, to its partners.

For the three months ended September 30, 2012 and 2011, the general partner was allocated $1,637 and $40, respectively, in incentive distribution rights. For the nine months ended September 30, 2012 and 2011, the general partner was allocated $3,256 and $40, respectively, in incentive distribution rights.

11. Unit-Based Compensation

A summary of the Company's nonvested phantom units as of September 30, 2012 and the changes during the nine months ended September 30, 2012 is presented below:

Nonvested Phantom Units	Grant	Weighted Average Grant Date Fair Value Per Unit
Nonvested at December 31, 2011	553,696	$20.15
Granted	223,792	28.05
Vested	(99,847)	22.59
Forfeited	(23,909)	21.69
Nonvested at September 30, 2012	653,732	$20.58

For the three months ended September 30, 2012 and 2011, compensation expense of $1,581 and $662, respectively, was recognized in the unaudited condensed consolidated statements of operations related to vested phantom unit grants. For the nine months ended September 30, 2012 and 2011, compensation expense of $3,180 and $1,944, respectively, was recognized in the unaudited condensed consolidated statements of operations related to vested phantom unit grants. As of September 30, 2012 and 2011, there was a total of $13,456 and $1,907, respectively, of unrecognized compensation costs related to nonvested phantom unit grants. These costs are expected to be recognized over a weighted-average period of approximately 2 years.

12. Employee Benefit Plans

The Company has domestic noncontributory defined benefit plans for both salaried employees as well as those employees represented by either the United Steelworkers ("USW") or the International Union of Operating Engineers ("IUOE"); who (i) were formerly employees of Penreco and became employees of the Company as a result of the acquisition of Penreco on January 3, 2008 ("Penreco Pension Plan") or (ii) were formerly employees of Murphy Oil Corporation and who became employees of the Company as a result of the Superior Acquisition on September 30, 2011 (the "Superior Pension Plan" and together with the Penreco Pension Plan, the "Pension Plan").

The Company also has domestic contributory defined benefit postretirement medical plans and contributory life insurance plans for (i) salaried employees, as well as those employees represented by either the International Brotherhood of Teamsters ("IBT"), USW or IUOE, who were formerly employees of Penreco and who became employees of the Company as a result of the acquisition of Penreco on January 3, 2008 ("Penreco Other Plan") or (ii) employees represented by the IUOE, who were formerly employees of Murphy Oil Corporation and who became employees of the Company as a result of the Superior Acquisition on September 30, 2011 ("Superior Other Plan"). Effective July 1, 2012, the Company has amended the Superior Pension Plan and Superior Other Plan, which curtailed Superior employees from accumulating additional benefits subsequent to December 31, 2012. For the three and nine months ended September 30, 2012, the Company recorded a $218 curtailment gain related to the Superior Pension Plan and a $6,983 curtailment gain related to the Superior Other Plan, all of which is recorded in general and administrative expense in the unaudited condensed consolidated statements of operations. All information presented below has been adjusted for this curtailment.

Table of Contents

The components of net periodic pension and other postretirement benefits cost (credit) for the three months ended September 30, 2012 and 2011 were as follows:

	For the Three Months Ended September 30,			
	2012		2011	
	Pension Benefits	Other Post Retirement Employee Benefits	Pension Benefits	Other Post Retirement Employee Benefits
Service cost	$323	$25	$24	$ —
Interest cost	507	3	332	5
Expected return on assets	(454)	—	(264)	—
Amortization of net (gain) loss	147	(3)	71	(1)
Prior service credit	—	(12)	—	(8)
Curtailment gain	(218)	(6,983)	—	—
Net periodic benefit cost (credit)	$305	$(6,970)	$163	$ (4)

The components of net periodic pension and other postretirement benefits cost (credit) for the nine months ended September 30, 2012 and 2011 were as follows:

	For the Nine Months Ended September 30,			
	2012		2011	
	Pension Benefits	Other Post Retirement Employee Benefits	Pension Benefits	Other Post Retirement Employee Benefits
Service cost	$773	$ 287	$73	$ —
Interest cost	1,750	181	998	14
Expected return on assets	(1,649)	—	(793)	—
Amortization of net (gain) loss	434	(5)	211	(2)
Prior service credit	—	(30)	—	(26)
Curtailment gain	(218)	(6,983)	—	—
Net periodic benefit cost (credit)	$1,090	$ (6,550)	$489	$ (14)

At September 30, 2012, the Company’s investments associated with its Pension Plan primarily consist of (i) cash and cash equivalents, (ii) mutual funds that are publicly traded and (iii) a commingled fund. The mutual funds are publicly traded and market prices of the mutual funds 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. The Company’s Pension Plan assets measured at fair value at September 30, 2012 and December 31, 2011 were as follows:

	September 30, 2012		December 31, 2011	
	Pension Assets		Pension Assets	
	Level 1	Level 2	Level 1	Level 2
Cash and cash equivalents	$19,516	$—	$22,243	$—
Equity	4,647	—	4,000	—
Foreign equities	1,801	—	691	—
Commingled fund	—	2,706	—	2,462
Balanced fund	2,935	—	—	—
Fixed income	7,255	—	6,646	—
	$36,154	$2,706	$33,580	$2,462

13. Earnings per Unit

The following table sets forth the computation of basic and diluted earnings per limited partner unit for the three and nine months ended September 30, 2012 and 2011:

Table of Contents

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In thousands, except unit data)			
Numerator for basic and diluted earnings per limited partner unit:				
Net income	$42,416	$19,614	$160,001	$16,164
General partner’s interest in net income	848	392	3,200	323
General partner’s incentive distribution rights	1,637	40	3,256	40
Nonvested share based payments	262	—	947	—
Net income available to limited partners	$39,669	$19,182	$152,598	$15,801
Denominator for basic and diluted earnings per limited partner unit:				
Basic weighted average limited partner units outstanding	57,746	41,828	54,827	39,352
Effect of dilutive securities:				
Participating securities — phantom units	80	9	40	16
Diluted weighted average limited partner units outstanding	57,826	41,837	54,867	39,368
Limited partners’ interest basic net income per unit	$0.69	$0.46	$2.78	$0.40
Limited partners’ interest diluted net income per unit	$0.69	$0.46	$2.78	$0.40

14. 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 Fuel Products segment produces a variety of fuel and fuel-related products including gasoline, diesel, jet fuel and heavy fuel oils. The results of the operations from such assets acquired as a result of the Superior Acquisition have been included since the date of acquisition, September 30, 2011. The 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 2011 Annual Report except that 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:

Table of Contents

Three Months Ended September 30, 2012	Specialty Products	Fuel Products	Combined Segments	Eliminations	Consolidated Total
Sales:					
External customers	$587,125	$592,693	$1,179,818	$—	$1,179,818
Intersegment sales	275,167	14,780	289,947	(289,947)	—
Total sales	$862,292	$607,473	$1,469,765	$(289,947)	$1,179,818
Depreciation and amortization	23,067	4,629	27,696	—	27,696
Operating income	36,107	62,747	98,854	—	98,854
Reconciling items to net income:					
Interest expense					(24,271)
Loss on derivative instruments					(32,257)
Other					268
Income tax expense					(178)
Net income					$42,416
Capital expenditures	$9,782	$4,497	$14,279	$—	$14,279

Three Months Ended September 30, 2011	Specialty Products	Fuel Products	Combined Segments	Eliminations	Consolidated Total
Sales:					
External customers	$477,489	$300,291	$777,780	$—	$777,780
Intersegment sales	285,559	13,271	298,830	(298,830)	—
Total sales	$763,048	$313,562	$1,076,610	$(298,830)	$777,780
Depreciation and amortization	17,222	—	17,222	—	17,222
Operating income	54,404	2,127	56,531	—	56,531
Reconciling items to net income:					
Interest expense					(12,577)
Loss on derivative instruments					(24,149)
Other					45
Income tax expense					(236)
Net income					$19,614
Capital expenditures	$10,032	$—	$10,032	$—	$10,032

Table of Contents

Nine Months Ended September 30, 2012	Specialty Products	Fuel Products	Combined Segments	Eliminations	Consolidated Total
Sales:					
External customers	$1,722,029	$1,714,371	$3,436,400	$—	$3,436,400
Intersegment sales	872,238	37,018	909,256	(909,256)	—
Total sales	$2,594,267	$1,751,389	$4,345,656	$(909,256)	$3,436,400
Depreciation and amortization	60,416	13,727	74,143	—	74,143
Operating income	114,750	97,577	212,327	—	212,327
Reconciling items to net income:					
Interest expense					(61,247)
Gain on derivative instruments					9,149
Other					382
Income tax expense					(610)
Net income					$160,001
Capital expenditures	$28,042	$8,693	$36,735	$—	$36,735

Nine Months Ended September 30, 2011	Specialty Products	Fuel Products	Combined Segments	Eliminations	Consolidated Total
Sales:					
External customers	$1,341,005	$775,785	$2,116,790	$—	$2,116,790
Intersegment sales	792,987	32,178	825,165	(825,165)	—
Total sales	$2,133,992	$807,963	$2,941,955	$(825,165)	$2,116,790
Depreciation and amortization	51,932	—	51,932	—	51,932
Operating income (loss)	106,359	(14,263)	92,096	—	92,096
Reconciling items to net income:					
Interest expense					(30,602)
Debt extinguishment costs					(15,130)
Loss on derivative instruments					(29,674)
Other					148
Income tax expense					(674)
Net income					$16,164
Capital expenditures	$30,667	$—	$30,667	$—	$30,667

	September 30, 2012	December 31, 2011
Segment assets:		
Specialty products	$1,739,012	$1,159,040
Fuel products	500,149	573,018
Total assets	$2,239,161	$1,732,058

b. Geographic Information

International sales accounted for less than 10% of consolidated sales in each of the three and nine months ended September 30, 2012 and 2011. 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 and other. The following table sets forth the major product category sales:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Specialty products:				
Lubricating oils	$ 237,037	$ 262,175	$ 795,223	$ 717,674
Solvents	120,358	126,709	377,873	380,687
Waxes	37,217	38,908	109,159	107,089
Packaged and synthetic specialty products	58,507	—	116,062	—
Fuels	313	1,047	1,701	2,470
Asphalt and other by-products	133,693	48,650	322,011	133,085
Total	$ 587,125	$ 477,489	$ 1,722,029	$ 1,341,005
Fuel products:				
Gasoline	302,875	132,286	841,202	355,519
Diesel	217,823	116,914	657,857	290,678
Jet fuel	37,113	47,190	125,311	114,650
Heavy fuel oils and other	34,882	3,901	90,001	14,938
Total	$ 592,693	$ 300,291	$ 1,714,371	$ 775,785
Consolidated sales	$ 1,179,818	$ 777,780	$ 3,436,400	$ 2,116,790

d. Major Customers

During the three and nine months ended September 30, 2012 and 2011, the Company had no customer that represented 10% or greater of consolidated sales.

15. Subsequent Events

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., which was converted into a Delaware limited liability company, Calumet Montana Refining, LLC, (“Montana”) at closing, and an insignificant affiliated company for estimated aggregate consideration of approximately $224,805, net of cash acquired, including an estimated $40,000 of income taxes to be paid in the fourth quarter of 2012 due to the conversion to a Delaware limited liability company and excluding certain purchase price adjustments (“Montana Acquisition”). Montana produces gasoline, middle distillates and asphalt, which is 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 Montana 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.

On October 16, 2012, the Company declared a quarterly cash distribution of $0.62 per unit on all outstanding units, or approximately $38,194 in aggregate, for the quarter ended September 30, 2012. The distribution will be paid on November 14, 2012 to unitholders of record as of the close of business on November 2, 2012. This quarterly distribution of $0.62 per unit equates to $2.48 per unit, or approximately $152,776 in aggregate on an annualized basis.

The fair value of the Company’s derivatives and long-term debt, excluding capital leases, has not changed materially subsequent to September 30, 2012.

Table of Contents

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

The historical 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,” “us”). The following discussion analyzes the financial condition and results of operations of the Company for the three and nine months ended September 30, 2012 and 2011. Unitholders should read the following discussion and analysis of the financial condition and results of operations for Calumet in conjunction with our 2011 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 plants 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, asphalt and waxes. Our specialty products are sold to domestic and international customers who purchase them primarily as raw material components for basic industrial, consumer and automotive goods. 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.

Third Quarter 2012 Update

We saw slight softening in product demand in our specialty products segment in the third quarter of 2012 compared to the second quarter of 2012. We noted a 32.6% increase in barrels of specialty products sold for the quarter ended September 30, 2012 compared to the same period in 2011, including the impact of incremental sales in the third quarter of 2012 from the Superior, Missouri, TruSouth and Royal Purple Acquisitions. Excluding incremental sales volume associated with the Superior, Missouri, TruSouth and Royal Purple Acquisitions, our specialty products sales volume decreased 5.0% compared to the same period in 2011 primarily due to the reduced production levels at our Shreveport refinery resulting from the April 28, 2012 shutdown by ExxonMobil of a crude oil pipeline serving the Shreveport refinery for a portion of its crude oil requirements. Our specialty products segment generated a gross profit margin of 15.4% for the three months ended September 30, 2012 as compared to a gross profit margin of 18.4% in the same period of 2011, as specialty products sales pricing decreased slightly while crude oil costs remained fairly constant throughout the third quarter of 2012.

Higher sales and production volume in our fuel products segment during the third quarter of 2012 allowed us to take advantage of higher market crack spreads. We noted a 76.4% increase in barrels of fuel products sold in the third quarter of 2012 compared to the same period in 2011, driven primarily by incremental fuel products sales from the Superior refinery partially offset by reduced production levels at our Shreveport refinery resulting from the April 28, 2012 shutdown by ExxonMobil of a crude oil pipeline serving the refinery for a portion of its crude oil requirements. As a result of the ExxonMobil pipeline shutdown, our Shreveport refinery run rates decreased by an average of approximately 8,000 bpd for the third quarter of 2012 compared to the first quarter of 2012, our most recent quarterly period with normalized run rates. We expect these decreased run rates will remain in effect until the ExxonMobil pipeline service is restored or our ability to receive crude oil by rail from other suppliers at our Shreveport refinery is expanded, which we expect to be completed in the fourth quarter of 2012. The fuel products segment generated a gross profit margin of 11.4% during the third quarter of 2012 compared to 2.9% in the same period of 2011. During the third quarter of 2012, we entered into additional derivative instruments, excluding a crude oil basis swap, due to the strength in forward crack spreads, adding 6.2 million barrels of derivative instruments for calendar years 2013 through 2015 at an average crack spread of $25.84 per barrel.

During the third quarter of 2012, the WCS heavy crude oil differential to NYMEX WTI averaged $15.41 per barrel below NYMEX WTI. In addition to the benefit from this Canadian heavy crude oil differential, our Superior refinery fuel products sales benefited from improved average Group 3 fuel products differentials. For example, the Group 3 diesel differential to U.S. Gulf Coast diesel widened $4.14 per barrel compared to the average differential in the second quarter of 2012. As we currently use U.S. Gulf Coast fuel products swaps to hedge our Group 3 fuel products selling price exposure we have benefited from this Group 3 strength relative to U.S. Gulf Coast pricing.

On October 1, 2012, we completed the acquisition from Connacher Oil and Gas Limited ("Connacher") of all the shares of common stock of Montana Refining Company, Inc., which was converted into a Delaware limited liability company, Calumet Refining, LLC, (“Montana”) at closing, and an insignificant affiliated company for estimated aggregate consideration of approximately $224.8 million, net of cash acquired, including an estimated $40.0 million of income taxes to be paid in the fourth quarter of 2012 due to the conversion to a Delaware limited liability company and excluding certain purchase price adjustments ("Montana Acquisition"). Montana produces gasoline, middle distillates and asphalt, which is marketed primarily into local markets in Washington, Montana, Idaho and Alberta, Canada. The Montana Acquisition was funded primarily with cash on hand with balance through borrowings under our revolving credit facility.

We generated $244.9 million in cash flow from operations during the third quarter of 2012. We generated distributable cash flow (as defined below in "Non-GAAP Financial Measures") of $92.5 million and $50.5 million for the third quarter of 2012 and 2011, respectively, and paid distributions of $35.9 million to our unitholders in the third quarter of 2012, an increase of $15.8 million over the same period in the prior year. 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) pay quarterly distributions to our unitholders, (iii) service our debt obligations 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 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 financial derivatives 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 September 30, 2012, we have derivative instruments for approximately 17.9 million barrels of fuel products through December 2015 at an average refining margin of $25.30 per barrel with average refining margins ranging from a low of $20.85 per barrel in the fourth quarter of 2012 to a high of $26.21 per barrel in 2015. Please refer to Note 8 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—Existing Commodity Derivative Instruments" and "—Interest Rate Risk" and "—Commodity Price Risk" for detailed information regarding our derivative instruments.

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

- sales volumes;
- production yields; and
- 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 refining 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 gross profit achieved on the incremental volumes.

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

Specialty products and fuel products gross profit. Gross profit is an important measure of our ability to maximize the profitability. We define gross profit for our segments 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 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 and a Group 3 2/1/1 or 3/2/1 market crack spread due to many factors, including derivative activities to hedge both our fuel products segment revenues and the cost

Table of Contents

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 and Superior, Wisconsin vicinities as compared to U.S. Gulf Coast and Group 3 postings, respectively.

In addition to the foregoing measures, we also monitor our selling, general and administrative expenditures, substantially all of which are incurred through our general partner.

Results of Operations for the Three and Nine Months Ended September 30, 2012 and 2011

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 and biodiesel in our fuel products segment. The table includes the results of operations at our Superior refinery commencing October 1, 2011, Missouri facility commencing on January 3, 2012, TruSouth facility commencing January 6, 2012 and Royal Purple facility commencing July 3, 2012.

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	% Change	2012	2011	% Change
	(In bpd)			(In bpd)		
Total sales volume (1)	96,620	62,337	55.0 %	95,117	58,546	62.5 %
Total feedstock runs (2)	95,708	63,567	50.6 %	95,079	60,529	57.1 %
Facility production: (3)						
Specialty products:						
Lubricating oils	14,966	15,017	(0.3)%	14,773	14,316	3.2 %
Solvents	9,066	10,963	(17.3)%	9,445	10,717	(11.9)%
Waxes	1,294	1,434	(9.8)%	1,268	1,234	2.8 %
Packaged and synthetic specialty products	1,584	—	100.0 %	1,342	—	100.0 %
Fuels	531	491	8.1 %	630	519	21.4 %
Asphalt and other by-products	12,805	8,984	42.5 %	13,729	8,660	58.5 %
Total	40,246	36,889	9.1 %	41,187	35,446	16.2 %
Fuel products:						
Gasoline	23,565	9,741	141.9 %	23,018	9,660	138.3 %
Diesel	21,625	13,470	60.5 %	21,641	11,896	81.9 %
Jet fuel	4,481	4,872	(8.0)%	4,321	4,495	(3.9)%
Heavy fuel oils and other	3,406	492	592.3 %	3,373	704	379.1 %
Total	53,077	28,575	85.7 %	52,353	26,755	95.7 %
Total facility production (3)	93,323	65,464	42.6 %	93,540	62,201	50.4 %

(1) Total sales volume includes sales from the production at our facilities and certain third-party facilities pursuant to supply and/or processing agreements and sales of inventories. Total sales volume includes the sale of purchased fuel product blendstocks such as ethanol and biodiesel in our fuel products segment sales. The increase in total sales volume for the three and nine months ended September 30, 2012 compared to the same periods in 2011 is due primarily to incremental sales of fuel products, asphalt and packaged and synthetic specialty products subsequent to the Superior, Missouri, TruSouth and Royal Purple Acquisitions.

(2) Total feedstock runs represent the barrels per day of crude oil and other feedstocks processed at our facilities and at certain third-party facilities pursuant to supply and/or processing agreements. The increase in the total feedstock runs for the three and nine months ended September 30, 2012 compared to the same periods in 2011 is due primarily to incremental feedstock runs from the Superior, Missouri, TruSouth and Royal Purple Acquisitions

partially offset by decreased run rates at our Shreveport refinery during the 2012 period due to the April 28, 2012 shutdown of the ExxonMobil pipeline serving this refinery for a portion of its crude oil requirements.

Table of Contents

(3) Total facility production represents the barrels per day of specialty products and fuel products yielded from processing crude oil and other feedstocks at our facilities and at certain third-party facilities, pursuant to supply and/or processing agreements, including such agreements with LyondellBasell. The difference between total facility production and total feedstock runs is primarily a result of the time lag between the input of feedstock and production of finished products and volume loss. The increase in total facility production for three and nine months ended September 30, 2012 compared to the same periods in 2011 is due primarily to the operational items discussed above in footnote 2 of this table.

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 in accordance with GAAP, please read "—Non-GAAP Financial Measures."

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In thousands)		(In thousands)	
Sales	$1,179,818	$777,780	$3,436,400	$2,116,790
Cost of sales	1,021,412	681,179	3,064,942	1,922,760
Gross profit	158,406	96,601	371,458	194,030
Operating costs and expenses:				
Selling	15,002	2,809	26,668	8,220
General and administration	12,810	11,339	41,333	26,923
Transportation	28,404	23,696	80,903	69,462
Taxes other than income taxes	1,723	1,683	5,371	4,246
Insurance recoveries	—	—	—	(8,698)
Other	1,613	543	4,856	1,781
Operating income	98,854	56,531	212,327	92,096
Other income (expense):				
Interest expense	(24,271)	(12,577)	(61,247)	(30,602)
Debt extinguishment costs	—	—	—	(15,130)
Realized gain (loss) on derivative instruments	(10,156)	(3,814)	20,486	(5,798)
Unrealized loss on derivative instruments	(22,101)	(20,335)	(11,337)	(23,876)
Other	268	45	382	148
Total other expense	(56,260)	(36,681)	(51,716)	(75,258)
Net income before income taxes	42,594	19,850	160,611	16,838
Income tax expense	178	236	610	674
Net income	$42,416	$19,614	$160,001	$16,164
EBITDA	$91,407	$47,107	$285,686	$106,214
Adjusted EBITDA	$121,389	$70,548	$313,350	$146,042
Distributable Cash Flow	$92,527	$50,487	$226,557	$94,076

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

44

Table of Contents

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

We believe that these non-GAAP measures are useful to analysts and investors as they exclude transactions not related to our core cash operating activities and provide metrics to analyze our ability to pay distributions. We believe that excluding these transactions allows investors to meaningfully 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. Distributable Cash Flow is used by us, our investors and analysts to analyze our ability to pay distributions.

The definitions of Adjusted EBITDA and Distributable Cash Flow that are presented in this Quarterly Report have been updated to 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 lenders under our revolving credit facility, and these measures are used by them to determine our compliance with certain covenants governing those debt instruments. Adjusted EBITDA and Distributable Cash Flow that are presented in this Quarterly Report for prior periods have been updated to reflect the use of the new calculations. 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, 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 September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In thousands)		(In thousands)	
Reconciliation of Net Income to EBITDA, Adjusted EBITDA and Distributable Cash Flow:				
Net income	$42,416	$19,614	$160,001	$16,164
Add:				
Interest expense	24,271	12,577	61,247	30,602
Debt extinguishment costs	—	—	—	15,130
Depreciation and amortization	24,542	14,680	63,828	43,644
Income tax expense	178	236	610	674
EBITDA	$91,407	$47,107	$285,686	$106,214
Add:				
Unrealized loss on derivatives	$22,101	$20,335	$11,337	$23,876
Realized gain (loss) on derivatives, not included in net income	1,494	(771)	904	4,366
Amortization of turnaround costs	3,154	2,542	10,315	8,288
Non-cash equity based compensation	3,233	1,335	5,108	3,298
Adjusted EBITDA	$121,389	$70,548	$313,350	$146,042
Less:				
Replacement capital expenditures (1)	$6,063	$6,608	$15,204	$14,204
Cash interest expense (2)	22,621	11,869	56,838	28,239
Turnaround costs	—	1,348	14,141	8,849
Income tax expense	178	236	610	674
Distributable Cash Flow	$92,527	$50,487	$226,557	$94,076

(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

	Nine Months Ended September 30,	
	2012	2011
	(In thousands)	
Reconciliation of Distributable Cash Flow, Adjusted EBITDA and EBITDA to net cash provided by (used in) operating activities:		
Distributable Cash Flow	$226,557	$94,076
Add:		
Replacement capital expenditures (1)	15,204	14,204
Cash interest expense (2)	56,838	28,239
Turnaround costs	14,141	8,849
Income tax expense	610	674
Adjusted EBITDA	$313,350	$146,042
Less:		
Unrealized loss on derivative instruments	11,337	23,876
Realized gain on derivatives, not included in net income	904	4,366
Amortization of turnaround costs	10,315	8,288
Non-cash equity based compensation	5,108	3,298
EBITDA	$285,686	$106,214
Add:		
Unrealized loss on derivative instruments	11,337	23,876
Cash interest expense (2)	(56,838)	(28,239)
Non-cash equity based compensation	5,108	3,298
Amortization of turnaround costs	10,315	8,288
Income tax expense	(610)	(674)
Provision for doubtful accounts	296	255
Debt extinguishment costs	—	(729)
Changes in assets and liabilities:		
Accounts receivable	(32,370)	(44,714)
Inventories	33,678	(109,787)
Other current assets	(3,470)	(2,352)
Turnaround costs	(14,141)	(8,849)
Derivative activity	904	4,928
Other assets	—	(197)
Accounts payable	26,845	32,158
Other liabilities	28,965	18,269
Other, including changes in noncurrent liabilities	(6,265)	(2,304)
Net cash provided by (used in) operating activities	$289,440	$(559)

(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 September 30, 2012 and 2011

Sales. Sales increased $402.0 million, or 51.7%, to $1,179.8 million in the three months ended September 30, 2012 from $777.8 million in the same period in 2011. Sales for each of our principal product categories in these periods were as follows:

	Three Months Ended September 30,		
	2012	2011	% Change
	(Dollars in thousands, except per barrel data)		
Sales by segment:			
Specialty products:			
Lubricating oils	$ 237,037	$ 262,175	(9.6)%
Solvents	120,358	126,709	(5.0)%
Waxes	37,217	38,908	(4.3)%
Packaged and synthetic specialty products (1)	58,507	—	100.0 %
Fuels (2)	313	1,047	(70.1)%
Asphalt and by-products (3)	133,693	48,650	174.8 %
Total specialty products	$ 587,125	$ 477,489	23.0 %
Total specialty products sales volume (in barrels)	3,716,000	2,803,000	32.6 %
Average specialty products sales price per barrel	$ 158.00	$ 170.35	(7.2)%
Fuel products:			
Gasoline	$ 302,875	$ 136,779	121.4 %
Diesel	262,902	163,779	60.5 %
Jet fuel	41,606	56,957	(27.0)%
Heavy fuel oils and other (4)	34,882	3,901	794.2 %
Hedging activities loss	(49,572)	(61,125)	(18.9)%
Total fuel products	$ 592,693	$ 300,291	97.4 %
Total fuel products sales volume (in barrels)	5,173,000	2,932,000	76.4 %
Average fuel products sales price per barrel (excluding hedging activities)	$ 124.16	$ 123.27	0.7 %
Average fuel products sales price per barrel (including hedging activities)	$ 114.57	$ 102.42	11.9 %
Total sales	$ 1,179,818	$ 777,780	51.7 %
Total sales volume (in barrels)	8,889,000	5,735,000	55.0 %

(1) Represents 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 products at the Shreveport, Superior, Princeton and Cotton Valley refineries.

(4) Represents heavy fuel oils and other products produced in connection with the production of fuels at the Shreveport and Superior refineries.

Specialty products segment sales for the three months ended September 30, 2012 increased $109.6 million, or 23.0%, primarily as a result of an increase in sales volume of 32.6% as compared to the same period in 2011. The increase in sales volume is due primarily to incremental asphalt sales volume associated with the Superior Acquisition, which closed on September 30, 2011, and incremental packaged and synthetic specialty products sales volume associated with the Royal Purple, TruSouth and Missouri Acquisitions, which closed on July 3, 2012, January 6, 2012 and January 3, 2012, respectively. Partially offsetting the increased sales volume was a decrease in the average selling price per barrel of $12.35, or 7.2%, due primarily to weaker demand for lubricating oils in the third quarter of 2012, while the average cost of crude oil and other feedstocks per barrel remained relatively consistent for the third quarter of 2012 as compared to the same period in 2011. Excluding incremental volumes from the Superior, Missouri, TruSouth and Royal Purple Acquisitions, the specialty products average sales price per barrel decreased 4.7% due to weaker demand in the third quarter of 2012 for lubricating oils and our sales volume decreased 5.0% quarter over quarter primarily due to decreased run rates at our Shreveport refinery resulting from the April 28, 2012 shutdown of the ExxonMobil pipeline serving this refinery for a portion of its crude oil requirements.

Table of Contents

Fuel products segment sales for the three months ended September 30, 2012 increased $292.4 million, or 97.4%, due primarily to increased sales volume as a result of the Superior Acquisition and an increase in the fuel products average selling price per barrel (excluding the impact of those realized hedging losses reflected in sales) of $0.89, or 0.7%, and an $11.6 million decrease in realized derivative losses recorded in sales on our fuel products cash flow hedges. The increase in the average selling price per barrel of 0.7% (excluding hedging activities) compares to a 5.9% decrease in the average price of crude oil per barrel as market crack spreads widened in the 2012 period compared to the same period in 2011. Excluding incremental fuel products sales volume associated with the Superior Acquisition, our fuel products sales volume decreased 8.6% in the third quarter of 2012 as compared to the same period in 2011 primarily as a result of decreased run rates at our Shreveport refinery resulting from the April 28, 2012 shutdown of the ExxonMobil pipeline serving this refinery for a portion of its crude oil requirements. Please see "Gross Profit" below for discussion of the net impact of our crude oil and fuel products derivative instruments.

Gross Profit. Gross profit increased $61.8 million, or 64.0%, to $158.4 million in the three months ended September 30, 2012 from $96.6 million in the same period in 2011. Gross profit for our specialty products and fuel products segments was as follows:

	Three Months Ended September 30,		
	2012	2011	% Change
	(Dollars in thousands, except per barrel data)		
Gross profit by segment:			
Specialty products:			
Gross profit	$90,575	$87,789	3.2 %
Percentage of sales	15.4 %	18.4 %	
Specialty products gross profit per barrel	$24.37	$31.32	(22.2)%
Fuel products:			
Gross profit excluding hedging activities	$109,407	$44,526	145.7 %
Hedging activities	$(41,576)	$(35,714)	16.4 %
Gross profit	$67,831	$8,812	669.8 %
Percentage of sales	11.4 %	2.9 %	
Fuel products gross profit per barrel (excluding hedging activities)	$21.15	$15.19	39.2 %
Fuel products gross profit per barrel (including hedging activities)	$13.11	$3.01	335.5 %
Total gross profit	$158,406	$96,601	64.0 %
Percentage of sales	13.4 %	12.4 %	

The increase in specialty products segment gross profit of $2.8 million quarter over quarter was due primarily to a 32.6% increase in sales volume previously discussed and lower operating costs, mainly repairs and maintenance, partially offset by a 7.2% decrease in the average selling price per barrel. Excluding incremental volumes from the Superior, Missouri, TruSouth and Royal Purple Acquisitions, the specialty products average sales price per barrel decreased 4.7% due to weaker demand in the third quarter of 2012 for lubricating oils and our sales volume decreased 5.0% quarter over quarter. Please see "Sales" above for additional discussion on sales volume.

The increase in fuel products segment gross profit of $59.0 million quarter over quarter was due primarily to a 76.4% increase in sales volume, mostly as a result of the Superior Acquisition, a 5.9% decrease in the average cost of crude oil per barrel and a 0.7% increase in the average sales price per barrel (excluding the impact of realized hedging losses reflected in sales), partially offset by increased realized losses on derivatives of $5.9 million. Due to the extremely volatile nature of the pricing differentials between NYMEX WTI and Canadian heavy and Bakken crude oils during 2012, our NYMEX WTI crude oil swap contracts entered into to hedge the purchase of crude oil at our Superior refinery as part of our crack spread hedging program were no longer closely correlated and we were required, under U.S. GAAP, to discontinue hedge accounting on these derivatives as of January 1, 2012. Effective April 1, 2012, we also voluntarily discontinued hedge accounting for our fuel products swap contracts entered into to hedge fuel products sales at our Superior refinery. Primarily as a result of discontinuing hedge accounting on these derivative instruments, we recorded a loss of $10.2 million to realized gain (loss) on derivative instruments in the unaudited condensed consolidated statements of operations for the three months ended September 30, 2012. The effective portion of realized gains or losses on crude oil and fuel products derivatives, under hedge accounting are recorded to cost of sales and sales, respectively. Total loss on settled derivative instruments reflected in gross profit, as discussed above, and realized gain (loss) on derivative instruments was $51.9 million for the third quarter of 2012, an increased loss of $13.8

Table of Contents

million quarter over quarter. Please see "Sales" above for additional discussion on average sales price per barrel and sales volume.

Selling. Selling expenses increased $12.2 million, or 434.1%, to $15.0 million in the three months ended September 30, 2012 from $2.8 million in the same period in 2011. This increase was primarily due to increased amortization expense of $6.3 million primarily related to the recording of intangible assets associated with the Missouri, TruSouth and Royal Purple Acquisitions, additional employee compensation costs from the TruSouth and Royal Purple Acquisitions with no similar expenses in the comparable period in the prior year and increased advertising expenses of $2.3 million.

General and administrative . General and administrative increased $1.5 million, or 13.0%, to $12.8 million in the three months ended September 30, 2012 from $11.3 million in the same period in 2011. The increase was due primarily to additional employee compensation costs from the Superior, TruSouth and Royal Purple Acquisitions with no similar expenses in the comparable period in the prior year, increased incentive compensation costs of $2.8 million and increased professional fees of $1.3 million, partially offset by a $7.2 million gain related to the curtailment of certain benefits in benefit plans covering employees at the Superior refinery.

Transportation. Transportation expenses increased $4.7 million, or 19.9%, to $28.4 million in the three months ended September 30, 2012 from $23.7 million in the same period in 2011. This increase is due primarily to incremental transportation expenses related to sales from the Superior and Royal Purple Acquisitions and higher freight rates.

Interest expense. Interest expense increased $11.7 million, or 93.0%, to $24.3 million in the three months ended September 30, 2012 from $12.6 million in the three months ended September 30, 2011, due primarily to additional outstanding long-term debt in the form of 2019 Notes issued to partially fund the Superior Acquisition and 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 September 30, 2012 and 2011.

	Three Months Ended September 30,	
	2012	2011
	(in thousands)	
Derivative loss reflected in sales	$(49,572)	$(61,125)
Derivative gain reflected in cost of sales	7,806	26,775
Derivative loss reflected in gross profit	$(41,766)	$(34,350)
Realized loss on derivative instruments	$(10,156)	$(3,814)
Unrealized loss on derivative instruments	(22,101)	(20,335)
Total derivative loss reflected in the unaudited condensed consolidated statements of operations	$(74,023)	$(58,499)
Total loss on derivative settlements	$(50,429)	$(38,939)

Realized loss on derivative instruments. Realized loss on derivative instruments increased $6.3 million to $10.2 million in the three months ended September 30, 2012 from $3.8 million for the three months ended September 30, 2011. The change was due primarily to an increased realized loss of approximately $4.8 million related to the settlement of derivative instruments which were not reflected in gross profit because of the loss of hedge accounting in 2012 on Superior refinery crude oil derivative instruments as Superior crude oil purchases and NYMEX WTI are no longer highly correlated and the settlement of fuel products derivative instruments related to the Superior refinery where hedge accounting has been discontinued.

Unrealized loss on derivative instruments. Unrealized loss on derivative instruments increased $1.8 million to $22.1 million in the three months ended September 30, 2012 from $20.3 million in the three months ended September 30, 2011. The change was due primarily to increased unrealized loss of approximately $35.0 million due primarily to the discontinuance of hedge accounting in 2012 for fuel products derivative instruments related to the Superior refinery and the loss of hedge accounting in 2012 on Superior refinery crude oil derivative instruments, as Superior crude oil purchases and NYMEX WTI are no longer highly correlated. This unrealized loss was partially offset by increased unrealized gain ineffectiveness of $30.6 million.

Table of Contents

Changes in Results of Operations for the Nine Months Ended September 30, 2012 and 2011

Sales. Sales increased $1,319.6 million, or 62.3%, to $3,436.4 million in the nine months ended September 30, 2012 from $2,116.8 million in the same period in 2011. Sales for each of our principal product categories in these periods were as follows:

	Nine Months Ended September 30,		
	2012	2011	% Change
	(Dollars in thousands, except per barrel data)		
Sales by segment:			
Specialty products:			
Lubricating oils	$ 795,223	$ 717,674	10.8 %
Solvents	377,873	380,687	(0.7)%
Waxes	109,159	107,089	1.9 %
Packaged and synthetic specialty products (1)	116,062	—	100.0 %
Fuels (2)	1,701	2,470	(31.1)%
Asphalt and other by-products (3)	322,011	133,085	142.0 %
Total specialty products	$ 1,722,029	$ 1,341,005	28.4 %
Total specialty products sales volume (in barrels)	10,633,000	8,249,000	28.9 %
Average specialty products sales price per barrel	$ 161.95	$ 162.57	(0.4)%
Fuel products:			
Gasoline	$ 880,406	$ 378,827	132.4 %
Diesel	775,893	413,063	87.8 %
Jet fuel	148,298	134,758	10.0 %
Heavy fuel oils and other (4)	90,001	14,938	502.5 %
Hedging activities loss	(180,227)	(165,801)	8.7 %
Total fuel products	$ 1,714,371	$ 775,785	121.0 %
Total fuel products sales volume (in barrels)	15,429,000	7,734,000	99.5 %
Average fuel products sales price per barrel (excluding hedging activities)	$ 122.79	$ 121.75	0.9 %
Average fuel products sales price per barrel (including hedging activities)	$ 111.11	$ 100.31	10.8 %
Total sales	$ 3,436,400	$ 2,116,790	62.3 %
Total sales volume (in barrels)	26,062,000	15,983,000	63.1 %

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

(4) Represents heavy fuel oils and other products produced in connection with the production of fuels at the Shreveport and Superior refineries.

Specialty products segment sales for the nine months ended September 30, 2012 increased $381.0 million, or 28.4%, primarily as a result of an increase in sales volume of 28.9% as compared to the same period in 2011. The increase in sales volume is due primarily to incremental asphalt sales volume associated with the Superior Acquisition, which closed on September 30, 2011, incremental packaged and synthetic specialty products sales volume associated with the Royal Purple, TruSouth and Missouri Acquisitions, which closed on July 3, 2012, January 6, 2012 and January 3, 2012, respectively, and an increase in lubricating oil sales volume driven by a 3.2% increase in production. Partially offsetting the increased sales volume was a decrease in the average selling price per barrel of $0.62, or 0.4%, while the average cost of crude oil per barrel remained relatively consistent for the nine months ended September 30, 2012 as compared to the same period in 2011. Excluding incremental sales volume associated with the Superior, Missouri, TruSouth and Royal Purple Acquisitions, our specialty products sales volume increased 2.5% as a result of an increase in lubricating oil sales volume driven by increased production, partially offset by decreased run rates at our Shreveport refinery resulting from the April 28, 2012 shutdown of the ExxonMobil pipeline serving this refinery for a portion of its crude oil requirements and the specialty products average sales price per barrel increased 3.1% compared to same period in 2011.

Table of Contents

Fuel products segment sales for the nine months ended September 30, 2012 increased $938.6 million, or 121.0%, due primarily to increased sales volume, as a result of the incremental fuel products sales volume from the Superior Acquisition. The fuels products average selling price per barrel (excluding the impact of those realized hedging losses reflected in sales) increased $1.04, or 0.9%. The increase in the average selling price per barrel of 0.9% (excluding hedging activities) compares to a 5.5% decrease in the average price of crude oil per barrel. Also impacting fuel product sales was a $14.4 million increase in realized derivative losses recorded in sales on our fuel products cash flow hedges. Excluding incremental fuel products sales volume associated with the Superior Acquisition, our fuel products sales volume increased 3.9% for the nine months ended September 30, 2012 as compared to the same period in 2011 primarily due to the planned turnaround at our Shreveport refinery in the first quarter of 2011 partially offset by decreased run rates at our Shreveport refinery resulting from the April 28, 2012 shutdown of the ExxonMobil pipeline serving this refinery for a portion of its crude oil requirements. Please see “Gross Profit” below for discussion of the net impact of our crude oil and fuel products derivative instruments.

Gross Profit. Gross profit increased $177.4 million, or 91.4%, to $371.5 million in the nine months ended September 30, 2012 from $194.0 million in the same period in 2011. Gross profit for our specialty products and fuel products segments was as follows:

	Nine Months Ended September 30,					
	2012		2011		% Change	
	(Dollars in thousands, except per barrel data)					
Gross profit by segment:						
Specialty products:						
Gross profit	$245,662		$193,988		26.6	%
Percentage of sales	14.3	%	14.5	%		
Specialty products gross profit per barrel	$23.10		$23.52		(1.8	)%
Fuel products:						
Gross profit excluding hedging activities	$263,417		$79,333		232.0	%
Hedging activities	$(137,621	)	$(79,291	)	73.6	%
Gross profit	$125,796		$42		299,414.3	%
Percentage of sales	7.3	%	—	%		
Fuel products gross profit per barrel (excluding hedging activities)	$17.07		$10.26		66.4	%
Fuel products gross profit per barrel (including hedging activities)	$8.15		$0.01		81,400.0	%
Total gross profit	$371,458		$194,030		91.4	%
Percentage of sales	10.8	%	9.2	%		

The increase in specialty products segment gross profit of $51.7 million for the nine months ended September 30, 2012 compared to the same period in 2011 was due primarily to a 28.9% increase in sales volume and lower operating costs, mainly repairs and maintenance, partially offset by a 0.4% decrease in the average selling price per barrel as discussed above. Excluding incremental volumes from the Superior, Missouri, TruSouth and Royal Purple Acquisitions, the specialty products average sales price per barrel increased 3.1% compared to same period in 2011. Please see "Sales" above for additional discussion on sales volume.

The increase in fuel products segment gross profit of $125.8 million for the nine months ended September 30, 2012 compared to the same period in 2011 was due primarily to a 99.5% increase in sales volume, mostly as a result of the Superior Acquisition, a 0.9% increase in the average sales price per barrel (excluding the impact of those realized hedging losses reflected in sales), and a 5.5% decrease in the average cost of crude oil per barrel partially offset by increased realized losses on derivatives of $58.3 million. Due to the extremely volatile nature of the pricing differentials between NYMEX WTI and Canadian heavy and Bakken crude oils during 2012, our NYMEX WTI crude oil swap contracts entered into to hedge the purchase of crude oil at our Superior refinery as part of our crack spread hedging program were no longer closely correlated and we were required, under U.S. GAAP, to discontinue hedge accounting on these derivatives as of January 1, 2012. Effective April 1, 2012, we also discontinued hedge accounting for our fuel products swap contracts entered into to hedge fuel products sales at our Superior refinery. Primarily as a result of discontinuing hedge accounting on these derivative instruments, we recorded a gain of $20.5 million to realized gain (loss) on derivative instruments in the unaudited condensed consolidated statements of operations for the nine months ended September 30, 2012. The effective portion of realized gains or losses on crude oil and fuel products derivatives, under hedge accounting are recorded to cost of sales and sales, respectively. Our fuel products segment gross profit for the nine months ended September 30, 2012 does not reflect any impacts of our derivative instruments related to the Superior refinery. Total loss on settled derivative instruments reflected in gross profit, as discussed above, and realized gain (loss) on derivative instruments was $117.3 million for the nine months ended September 30, 2012, an increased loss of $30.9 million period over period.

Selling. Selling expenses increased $18.4 million, or 224.4%, to $26.7 million in the nine months ended September 30, 2012 from $8.2 million in the same period in 2011. This increase was primarily due to increased amortization expense of $7.6 million primarily related to the recording of intangible assets associated with the Missouri, TruSouth and Royal Purple Acquisitions, additional employee compensation costs from the TruSouth and Royal Purple Acquisitions with no similar expenses in the comparable period in the prior year and increased advertising expenses of $4.9 million.

General and administrative. General and administrative increased $14.4 million, or 53.5%, to $41.3 million in the nine months ended September 30, 2012 from $26.9 million in the same period in 2011. The increase was due primarily to additional employee compensation costs from the Superior, Missouri, TruSouth and Royal Purple Acquisitions with no similar expenses in the comparable period in the prior year, increased professional fees of $6.4 million and increased incentive compensation costs of $4.8 million, partially offset by a $7.2 million gain related to the curtailment of certain benefits in benefit plans covering employees at the Superior refinery.

Transportation. Transportation expenses increased $11.4 million, or 16.5%, to $80.9 million in the nine months ended September 30, 2012 from $69.5 million in the same period in 2011. This increase is due primarily to incremental transportation expenses related to sales from the Superior and Royal Purple Acquisitions, increased sales volume of lubricating oils, as well as higher freight rates.

Insurance recoveries. Insurance recoveries were $8.7 million for the nine months ended September 30, 2011. The gain was related to a claim settled in the second quarter of 2011 with insurers related to the failure of an environmental operating unit at the Shreveport refinery in the first quarter of 2010.

Interest expense. Interest expense increased $30.6 million, or 100.1%, to $61.2 million in the nine months ended September 30, 2012 from $30.6 million in the nine months ended September 30, 2011. This increase is due primarily to higher interest rates associated with the 2019 and 2020 Notes as compared to the prior term loan that was repaid in full and extinguished in connection with the issuance of the 2019 Notes, as well as additional outstanding long-term debt in the form of 2019 Notes issued to partially fund the Superior Acquisition and 2020 Notes issued to partially fund the Royal Purple Acquisition.

Debt extinguishment costs. Debt extinguishment costs were $15.1 million during the nine months ended September 30, 2011. The debt extinguishment costs were related to the extinguishment of the Company's term loan with proceeds from the issuance of the 2019 Notes.

Derivative activity. The following table details the impact of our derivative instruments on the unaudited condensed consolidated statements of operations for the nine months ended September 30, 2012 and 2011.

	Nine Months Ended September 30,	
	2012	2011
	(In thousands)	
Derivative loss reflected in sales	$(180,227)	$(165,801)
Derivative gain reflected in cost of sales	42,430	85,209
Derivative loss reflected in gross profit	$(137,797)	$(80,592)
Realized gain (loss) on derivative instruments	$20,486	$(5,798)
Unrealized loss on derivative instruments	(11,337)	(23,876)
Derivative loss reflected in interest expense	—	(702)
Total derivative loss reflected in the unaudited condensed consolidated statements of operations	$(128,648)	$(110,968)
Total loss on derivative settlements	$(116,408)	$(82,727)

Realized gain (loss) on derivative instruments. Realized gain (loss) on derivative instruments increased $26.3 million to a gain of $20.5 million in the nine months ended September 30, 2012 from a loss of $5.8 million for the nine months ended September 30, 2011. The change was due primarily to an increased realized gain of approximately $49.7 million related to the settlement of derivative instruments which were not reflected in gross profit because of the loss of hedge accounting in 2012 on Superior refinery crude oil derivative instruments as Superior crude oil purchases and NYMEX WTI are no longer highly correlated as well as the discontinuance of hedge accounting for fuel products derivative instruments related to the Superior refinery. Partially offsetting this increased realized gain was an increased realized loss due to ineffectiveness of approximately $17.1 million related to settlements of cash flow hedges and increased realized losses of $4.9 million related to natural gas and crude oil derivative settlements included in our specialty products segment which are not designated as cash flow hedges.

Unrealized loss on derivative instruments. Unrealized loss on derivative instruments decreased $12.5 million, to $11.3 million in the nine months ended September 30, 2012 from $23.9 million in the nine months ended September 30, 2011. This change was due primarily to increased unrealized gains on ineffectiveness of approximately $13.5 million.

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 I Item 7 in our 2011 Annual Report. There have been no material changes in that information other than as discussed below. Also, see Note 7 under Part I Item 1 "Financial Statements—Notes to Unaudited Condensed Consolidated Financial Statements" for additional discussion related to 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 unitholders and general partner and debt service. We expect that our principal uses of cash in the future will be for distributions to our limited partners 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.

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

	Nine Months Ended September 30,	
	2012	2011
	(In thousands)	
Net cash provided by (used in) operating activities	$289,440	$(559)
Net cash used in investing activities	(413,823)	(470,132)
Net cash provided by financing activities	314,857	470,720
Net increase in cash and cash equivalents	$190,474	$29

Operating Activities. Operating activities provided cash of $289.4 million during the nine months ended September 30, 2012 compared to using cash of $0.6 million during the same period in 2011. The increase in cash provided by operating activities is due primarily to increased net income of $143.8 million and a decrease in working capital requirements, primarily through increased accounts payable and accrued interest of $47.2 million during the nine months ended September 30, 2012 compared to the same period in 2011.

Investing Activities. Cash used in investing activities decreased to $413.8 million during the nine months ended September 30, 2012 compared to $470.1 million during the nine months ended September 30, 2011. The decrease is due primarily to the purchase price of the Superior Acquisition of $441.6 million in the prior period, compared to a combined purchase price of $379.0 million for the Missouri, TruSouth and Royal Purple Acquisitions, which closed during 2012 .

Table of Contents

Financing Activities. Financing activities provided cash of $314.9 million in the nine months ended September 30, 2012 compared to $470.7 million during the nine months ended September 30, 2011. This change is due primarily to the decreased net proceeds from a public offering of common units (including the general partner's contribution) of $138.2 million, decreased net proceeds from a private placement of senior notes of $315.8 million and increased distributions to our unitholders of $37.8 million, partially offset by the repayment of the senior secured first lien term facility in April 2011 of $367.4 million.

On May 8, 2012, we completed a public offering of our common units in which we sold 6,000,000 common units to the underwriters of the offering at a price to the public of $25.50 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 $146.6 million and were used to repay borrowings under our revolving credit facility. Underwriting discounts totaled $6.2 million. Our general partner contributed $3.1 million to maintain its 2% general partner interest.

On October 1, 2012, we completed the Montana Acquisition for estimated aggregate consideration of approximately $224.8 million, net of cash acquired, including an estimated $40.0 million of income taxes to be paid in the fourth quarter of 2012 due to the conversion to a Delaware limited liability company and excluding certain purchase price adjustments. The Montana Acquisition was funded primarily with cash on hand with the balance through borrowings under our revolving credit facility.

On October 16, 2012, we declared a quarterly cash distribution of $0.62 per unit on all outstanding units, or approximately $38.2 million in aggregate, for the quarter ended September 30, 2012. The distribution will be paid on November 14, 2012 to unitholders of record as of the close of business on November 2, 2012. This quarterly distribution of $0.62 per unit equates to $2.48 per unit, or approximately $152.8 million in aggregate on an annualized basis.

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.

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

	Nine Months Ended September 30,	
	2012	2011
	(In thousands)	
Capital improvement expenditures	$21,531	$16,463
Replacement capital expenditures	6,283	10,595
Environmental capital expenditures	8,921	3,609
Total	$36,735	$30,667

We anticipate that future capital expenditure requirements will be provided primarily through cash flow from operations and available borrowings under our revolving credit facility. Our capital improvement expenditures have increased during the nine months ended September 30, 2012 as compared to the same period in 2011 due primarily to incremental expenditures at our Superior refinery related to our crude oil rail loading project. Our environmental capital expenditures have increased during nine months ended September 30, 2012 as compared to the same period in 2011 due primarily to expenditures related to the Global Settlement with the LDEQ and OSHA compliance issues. Please read Note 6 of Part I Item 1 "Financial Statements—Commitments and Contingencies—Environmental" for additional information on the Global Settlement and OSHA compliance issues.

We estimate our replacement and environmental capital expenditures will be approximately $12.0 million for the remainder of 2012. These estimated amounts for 2012 include a portion of the $4.0 million to $8.0 million in environmental projects to be spent over the next four 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" for additional information.

Table of Contents

Additionally, we anticipate future turnaround spending requirements will be minimal for the remainder of 2012 and between $50.0 million and $55.0 million in 2013. We expect these expenditures will be funded primarily through cash flow from operations and borrowings under our revolving credit facility.

Debt and Credit Facilities

As of September 30, 2012, our primary debt and credit instruments consist 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 September 30, 2012, we believe we were in compliance with all covenants under the debt instruments in place at September 30, 2012 and have adequate liquidity to conduct our business.

Short Term Liquidity

As of and for the three and nine months ended September 30, 2012, our principal sources of short-term liquidity were (i) $477.8 million of availability under our revolving credit facility and (ii) $190.5 million of cash from cash flow from operations. The loan commitments under our revolving credit facility can be used to fund borrowings for general partnership purposes, capital expenditures, distributions to our unitholders and 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 September 30, 2012, we had availability on our revolving credit facility of $477.8 million, based on a $658.5 million borrowing base, $180.7 million in outstanding standby letters of credit and no 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 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 due to normal changes in working capital, payments of quarterly distributions to unitholders and debt service costs. Specifically, the amount borrowed under our revolving credit facility is typically at its highest level after we pay for the majority of our crude oil supplies on the 20th day of every month per standard industry terms. The maximum revolving credit facility borrowings during the quarter ended September 30, 2012 were $22.5 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 September 30, 2012, availability for additional borrowings under our revolving credit facility was approximately $389.4 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 September 30, 2012, this margin was 125 basis points for prime and 250 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 0.375% to 0.50% per annum depending on the average daily available unused borrowing capacity. 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 availability under the revolving credit facility at least equal to the greater of (i) 15% 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 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 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 our revolving credit facility, by the same percentage as the percentage increase in our revolving credit agreement commitments), 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 over us.

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 issuing 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. As of September 30, 2012, we had $600.0 million in 2019 Notes and $275.0 million in 2020 Notes outstanding. As of December 31, 2011, we had $600.0 million in 2019 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 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 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 2020 Notes, see Note 7 under Part I Item 1 “Financial Statements—Notes to Unaudited Condensed Consolidated Financial Statements.”

For additional information regarding our 2019 Notes, see Note 7 “Long-Term Debt” in Part II Item 8 “Financial Statements and Supplementary Data” of our 2011 Annual Report.

Master Derivative Contracts

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. We had no additional letters of credit or cash margin posted with any hedging counterparty as of September 30, 2012. 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 has not changed materially subsequent to September 30, 2012. 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.

Additionally, we have a collateral sharing 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 thereto.

Contractual Obligations and Commercial Commitments

The following table summarizes our contractual cash obligations as of September 30, 2012 at current maturities and reflects only those line items that have materially changed since December 31, 2011:

		Payments Due by Period			
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
	(In thousands)				
Operating activities:					
Interest on long-term debt at contractual rates (1)	$600,719	$91,232	$174,692	$169,206	$165,589
Operating lease obligations (2)	73,202	22,979	27,272	12,174	10,777
Letters of credit (3)	180,688	180,688	—	—	—
Purchase commitments (4)	1,516,326	1,230,756	266,338	19,232	—
Financing activities:					
Capital lease obligations	5,720	783	845	670	3,422
Long-term debt obligations, excluding capital lease obligations	875,025	—	—	25	875,000
Total obligations	$3,251,680	$1,526,438	$469,147	$201,307	$1,054,788

(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 the use of land, storage tanks, compressor stations, railcars, 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 ConocoPhillips related to the LVT unit at its Lake Charles, Louisiana refinery (the “LVT Feedstock Agreement”). Pursuant to the LVT Feedstock Agreement, ConocoPhillips 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 $79.2 million of feedstock for the LVT unit in each fiscal year of the term based on pricing estimates as of

Table of Contents

September 30, 2012. This amount is not included in the table above. If the Base Volume is not supplied at any point during the first five years of the ten year term, a penalty for each gallon of shortfall must be paid to us as liquidated damages.
For additional information regarding our expected capital and turnaround expenditures for the remainder of 2012 and 2013, for which we have not contractually committed, refer to “Capital Expenditures” above.

Off-Balance Sheet Arrangements
As of September 30, 2012, we had approximately $73.2 million in operating lease commitments. We did not enter into any material off-balance sheet debt or operating lease transactions during the quarter.

Critical Accounting Policies and Estimates
For additional discussion regarding our critical accounting policies and estimates, see “Critical Accounting Policies and Estimates” under Part I Item 7 of our 2011 Annual Report.

Recent Accounting Pronouncements
For additional discussion regarding recent accounting pronouncements, see Note 2 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 I Item 7A in our 2011 Annual Report and Item 3 of our Quarterly Reports on Form 10-Q for the three months ended March 31, 2012 (the “2012 First Quarterly Report”) and for the six months ended June 30, 2012 ("the "2012 Second Quarterly Report"). There have been no material changes in that information other than as discussed below. Also, see Note 8 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
Holding all other variables constant, we expect a $1 increase in the applicable commodity prices would change our recorded mark-to-market valuation by the following amounts based upon the volumes hedged as of September 30, 2012:

	In millions
Crude oil swaps	$17.9
Crude oil basis swaps	$0.9
Diesel swaps	$(10.7)
Jet fuel swaps	$(4.5)
Gasoline swaps	$(2.6)
Natural gas swaps	$0.6

Interest Rate Risk
Our profitability and cash flows are affected by changes in interest rates, specifically LIBOR and prime rates. The primary purpose of our interest rate risk management activities is to hedge our exposure to changes in interest rates. Historically, our policy has been to enter into interest rate swap agreements to hedge up to 75% of our interest rate risk related to variable rate debt. With the issuances of our 2019 and 2020 Notes, which constitute fixed rate debt, we do not expect to enter into additional hedges to fix our interest rates.
We are exposed to market risk from fluctuations in interest rates. As of September 30, 2012, we had borrowings of of less than $0.1 million variable rate debt outstanding under our revolving credit facility. Holding other variables constant (such as debt levels), a one hundred basis point change in interest rates on our variable rate debt as of September 30, 2012 would not have an impact on net income and cash flows for 2012.

Table of Contents

Existing Commodity Derivative Instruments

We are also subject to the risk that the crude oil and fuel products derivatives we use to hedge against fuel products crack spread volatility do not provide adequate protection against volatility. All of the crude oil derivatives in our hedge portfolio are based on the market price of NYMEX WTI and the fuel products derivatives are all based on U.S. Gulf Coast market prices. In recent periods, the spread between NYMEX WTI and other crude oil indices (specifically LLS and Brent on which a portion of our crude oil purchases are based) has widened, which has led to more of our crude oil hedges not being as effective. To the extent the spread between NYMEX WTI and the other crude oil indices stays at current levels or continues to widen, our hedges could continue to become less effective and not provide adequate protection against crude oil price volatility. Refer to Note 8 under Part I Item 1 “Financial Statements—Notes to Unaudited Condensed Consolidated Financial Statements” for discussion on the discontinuance of hedge accounting related to crude oil, diesel and gasoline derivatives related to crack spread hedging at our Superior refinery.

Fuel Products Segment

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 Canadian heavy crude oil versus NYMEX WTI crude oil basis swaps as of September 30, 2012 disclosed in Note 8 under Part I Item 1 “Financial Statements—Notes to Unaudited Condensed Consolidated Financial Statements”.

Crude Oil and Fuel Products Swap Contracts by Expiration Dates	Barrels	BPD	Implied Crack Spread ($/Bbl)
Fourth Quarter 2012	2,622,000	28,500	$20.85
Calendar Year 2013	7,605,000	20,836	26.00
Calendar Year 2014	4,195,000	11,493	26.07
Calendar Year 2015	3,467,500	9,500	26.21
Totals	17,889,500		
Average price			$25.30

Specialty Products Segment

The following provides a summary of our crude oil derivatives related to crude oil purchases in our specialty products segment as of September 30, 2012, which we disclose in Note 8 under Part I Item 1 “Financial Statements—Notes to Unaudited Condensed Consolidated Financial Statements,” none of which were designated as cash flow hedges. As of September 30, 2012, we purchased a crude oil derivative swap for 200,000 bbls in the second quarter of 2012 related to future crude oil purchases in its specialty segment, which is not designated as a cash flow hedge. We subsequently sold the crude oil derivative swap in the third quarter of 2012, and the net impact of these two trades is a net gain of $1.0 million and $1.6 million, respectively, that has been recorded to unrealized gain in the unaudited condensed consolidated statements of operations for the three and nine months ended September 30, 2012. This gain will be realized in January 2013 and will be recorded to realized gain (loss) in the unaudited condensed consolidated statement of operations.

The following table provides a summary of our natural gas derivatives related to natural gas purchases in our specialty products segment as of September 30, 2012, which we disclose in Note 8 under Part I Item 1 “Financial Statements—Notes to Unaudited Condensed Consolidated Financial Statements,” none of which were designated as cash flow hedges.

Natural Gas Swap Contracts by Expiration Dates	MMBtu	$/MMBtu
Fourth Quarter 2012	600,000	4.08
Totals	600,000	
Average price		$4.08

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

Table of Contents

by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of September 30, 2012 at the reasonable assurance level.

(b) Changes in Internal Control over Financial Reporting

There was no change in our internal control over financial reporting during the third quarter of 2012 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

We completed the Missouri Acquisition on January 3, 2012, the TruSouth Acquisition on January 6, 2012, the Royal Purple Acquisition on July 3, 2012 and the Montana Acquisition on October 1, 2012. These include certain existing information systems and internal controls over financial reporting that previously existed. We are currently in the process of evaluating and integrating Missouri, TruSouth and Royal Purple historical internal controls over financial reporting with ours. We expect to complete this integration during 2013.

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

There have been no material changes in the risk factors previously disclosed in our 2011 Annual Report under the Part I Item 1A “Risk Factors.”

In addition to the other information set forth in this Quarterly Report, you should carefully consider the factors discussed in Part I Item 1A “Risk Factors” in our 2011 Annual Report, which could materially affect our business, financial condition or future results. The risks described in this Quarterly Report and in our 2011 Annual Report are not the only risks facing the Company. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition or future results.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

None.

Item 5. Other Information

None.

Item 6. Exhibits

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

Table of Contents

Exhibit Number	Description
2.1	Share Purchase Agreement, dated as of August 14, 2012, among Calumet Specialty Products Partners, L.P. and Connacher Oil and Gas Limited (incorporated by reference to Exhibit 2.1 to the Registrant's Current Report on Form 8-K filed with the Commission on August 20, 2012 (File No. 000-51734)).
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:	November 7, 2012	By:	/s/ R. Patrick Murray, II R. Patrick Murray, II Vice President, Chief Financial Officer and Secretary (Authorized Person and Principal Accounting Officer)

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