Calumet Specialty Products Partners, L.P.
Form 10-K
February 29, 2016
Table of Contents

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K

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

For the fiscal year ended December 31, 2015

OR

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

Commission file number 000-51734
Calumet Specialty Products Partners, L.P.
(Exact Name of Registrant as Specified in Its Charter)

Delaware	35-1811116
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification Number)

2780 Waterfront Parkway East Drive
Suite 200
Indianapolis, Indiana 46214
(317) 328-5660
(Address, Including Zip Code, and Telephone Number,
Including Area Code, of Registrant's Principal Executive Offices)

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of Each Class	Name of Each Exchange on Which Registered
Common units representing limited partner interests	The NASDAQ Stock Market LLC

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:
NONE.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes þ No ¨

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No þ

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 þ 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 Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes þ No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. þ

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

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

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

The aggregate market value of the common units held by non-affiliates of the registrant was approximately $1,514.9 million on June 30, 2015, based on $25.46 per unit, the closing price of the common units as reported on the NASDAQ Global Select Market on such date.

On February 29, 2016, there were 75,884,400 common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

NONE.

Table of Contents

CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
FORM 10-K — 2015 ANNUAL REPORT
Table of Contents

		Page
PART I		
Items 1 and 2.	Business and Properties	3
Item 1A.	Risk Factors	27
Item 1B.	Unresolved Staff Comments	46
Item 3.	Legal Proceedings	47
Item 4.	Mine Safety Disclosures	47
PART II		
Item 5.	Market for Registrant’s Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities	48
Item 6.	Selected Financial Data	49
Item 7.	Management’s Discussion and Analysis of Financial Condition and Results of Operations	55
Item 7A.	Quantitative and Qualitative Disclosures About Market Risk	79
Item 8.	Financial Statements and Supplementary Data	84
Item 9.	Changes in and Disagreements With Accountants on Accounting and Financial Disclosure	150
Item 9A.	Controls and Procedures	150
Item 9B.	Other Information	150
PART III		
Item 10.	Directors, Executive Officers of Our General Partner and Corporate Governance	151
Item 11.	Executive and Director Compensation	155
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters	178
Item 13.	Certain Relationships and Related Transactions and Director Independence	181
Item 14.	Principal Accounting Fees and Services	183
PART IV		
Item 15.	Exhibits	185

Table of Contents

FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K (this “Annual Report”) includes certain “forward-looking statements.” These statements can be identified by the use of forward-looking terminology including “may,” “intend,” “believe,” “expect,” “anticipate,” “estimate,” “continue,” or other similar words. The statements regarding (i) estimated capital expenditures as a result of required audits or required operational changes or other environmental and regulatory liabilities, (ii) estimated capital expenditures as a result of our planned organic growth projects and estimated annual EBITDA contributions from such projects, (iii) our anticipated levels of, use and effectiveness of derivatives to mitigate our exposure to crude oil price changes, natural gas price changes and fuel products price changes, (iv) estimated costs of complying with the U.S. Environmental Protection Agency’s (“EPA”) Renewable Fuel Standard, including the prices paid for Renewable Identification Numbers (“RINs”), (v) our ability to meet our financial commitments, minimum quarterly distributions to our unitholders, debt service obligations, debt instrument covenants, contingencies and anticipated capital expenditures and (vi) our access to capital to fund capital expenditures and our working capital needs and our ability to obtain debt or equity financing on satisfactory terms, as well as other matters discussed in this Annual Report that are not purely historical data, are forward-looking statements. These forward-looking statements are based on our current expectations and beliefs concerning future developments and their potential effect on us. While management believes that these forward-looking statements are reasonable as and when made, there can be no assurance that future developments affecting us will be those that we anticipate. All comments concerning our expectations for future sales and operating results are based on our forecasts for our existing operations and do not include the potential impact of any future acquisitions. Our forward-looking statements involve significant risks and uncertainties (some of which are beyond our control) and assumptions that could cause actual results to differ materially from our historical experience and our present expectations or projections. Known material factors that could cause our actual results to differ from those in the forward-looking statements are those described in Part I, Item 1A “Risk Factors” of this Annual 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 Annual Report to “Calumet Specialty Products Partners, L.P.,” “Calumet,” “the Company,” “we,” “our,” “us like terms refer to Calumet Specialty Products Partners, L.P. and its subsidiaries. References to “Predecessor” in this Annual Report refer to Calumet Lubricants Co., Limited Partnership and its subsidiaries, the assets and liabilities of which were contributed to Calumet Specialty Products Partners, L.P. and its subsidiaries upon the completion of our initial public offering in 2006. References in this Annual 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

Items 1 and 2. Business and Properties

Overview

We are a leading independent producer of high-quality, specialty hydrocarbon products in North America. We are headquartered in Indianapolis, Indiana, and own specialty and fuel products facilities primarily located in northwest Louisiana, northwest Wisconsin, northern Montana, western Pennsylvania, Texas, New Jersey, eastern Missouri and North Dakota. We own and lease oilfield services locations in Texas, Oklahoma, Louisiana, Arkansas, Colorado, Utah, Wyoming, Montana, New Mexico, New York, North Dakota, Pennsylvania and Ohio. We own and lease additional facilities, primarily related to production and distribution of specialty, fuel and oilfield services products, throughout the United States ("U.S."). Our business is organized into three segments: specialty products, fuel products and oilfield services. In our specialty products segment, we process crude oil and other feedstocks into a wide variety of customized lubricating oils, white mineral oils, solvents, petrolatums and waxes. Our specialty products are sold to domestic and international customers who purchase them primarily as raw material components for basic industrial, consumer and automotive goods. We also blend and market specialty products through our Royal Purple, Bel-Ray, TruFuel and Quantum brands. In our fuel products segment, we process crude oil into a variety of fuel and fuel-related products, including gasoline, diesel, jet fuel, asphalt and heavy fuel oils, and from time to time resell purchased crude oil to third party customers. Our oilfield services segment manufactures and markets products and provides oilfield services including drilling fluids, completion fluids and solids control services to the oil and gas exploration industry throughout the U.S. For the year ended December 31, 2015, approximately 32.5% of our sales and 62.3% of our gross profit were generated from our specialty products segment, approximately 60.8% of our sales and 28.0% of our gross profit were generated from our fuel products segment and approximately 6.7% of our sales and 9.7% of our gross profit were generated from our oilfield services segment.

Our Primary Operating Assets

Our primary operating assets consist of:

Refinery/Facility	Location	Year Acquired	Current Feedstock Throughput Capacity in barrels per day ("bpd")	Products
Shreveport	Louisiana	2001	60,000	Specialty lubricating oils and waxes, gasoline, diesel, jet fuel and asphalt
Superior	Wisconsin	2011	45,000	Gasoline, diesel, asphalt and heavy fuel oils
Montana	Montana	2012	25,000	Gasoline, diesel, jet fuel and asphalt
San Antonio	Texas	2013	21,000	Diesel, jet fuel, gasoline, other fuel products and solvents
Cotton Valley	Louisiana	1995	13,500	Specialty solvents used principally in the manufacture of paints, cleaners, automotive products and drilling fluids
Princeton	Louisiana	1990	10,000	Specialty lubricating oils, including process oils, base oils, transformer oils and refrigeration oils, and asphalt
Karns City	Pennsylvania	2008	5,500	White mineral oils, solvents, petrolatums, gelled hydrocarbons, cable fillers and natural petroleum sulfonates
Dickinson	Texas	2008	1,300	White mineral oils, compressor lubricants, natural petroleum sulfonates and biodiesel
Royal Purple	Texas	2012	N/A	

				Specialty products including premium industrial and consumer synthetic lubricants
Bel-Ray	New Jersey	2013	N/A	Specialty products including premium industrial and consumer synthetic lubricants and greases
Missouri	Missouri	2012	N/A	Specialty products including polyolester-based synthetic lubricants

Drilling and Oilfield Services Assets. Anchor Drilling Fluids and Anchor Oilfield Services (as defined below) manufacture and market specialty products and provide oilfield services including drilling fluids, completion fluids and solids control services to the oil and gas exploration industry. We design, manufacture and package these specialty products at our locations in Texas, Oklahoma, Louisiana, Arkansas, Colorado, Utah, Wyoming, Montana, New Mexico, New York, North Dakota, Pennsylvania and Ohio. These locations serve the great majority of major onshore oil fields in the U.S.

Table of Contents

Crude Oil Logistics Assets. We own and operate seven crude oil loading facilities and related assets in North Dakota and Montana, which provide us the ability to transport crude oil directly from the point of lease, into our crude oil loading facilities and then onto the Enbridge Pipeline System ("Enbridge Pipeline") where it can be routed to our Superior refinery and/or third party customers.

Storage, Distribution and Logistics Assets. We own and operate product terminals in Burnham, Illinois ("Burnham"), Rhinelander, Wisconsin ("Rhinelander"), Crookston, Minnesota ("Crookston"), and Proctor, Minnesota ("Duluth"), with aggregate storage capacities of approximately 150,000, 166,000, 156,000 and 200,000 barrels, respectively. These terminals, as well as additional owned and leased facilities throughout the U.S., facilitate the distribution of products in the Upper Midwest, East Coast, West Coast and Mid-Continent regions of the U.S. and Canada.

We also use approximately 2,900 leased railcars to receive crude oil or distribute our products throughout the U.S. and Canada. In total, we have approximately 14.1 million barrels of aggregate storage capacity at our facilities and leased storage locations.

Business Strategies

Our management team is dedicated to improving our operations by executing the following strategies:

- Concentrate on Stable Cash Flows. We intend to continue to focus on operating assets and businesses that generate stable cash flows over time. Approximately 32.5% of our sales and 62.3% of our gross profit in 2015 were generated by the sale of specialty products, a segment of our business which is characterized by stable customer relationships due to our customers' requirements for the highly specialized products we provide. In addition, we manage our exposure to crude oil price fluctuations in this segment by passing on incremental feedstock costs to our specialty products customers. In our fuel products segment, which accounted for 60.8% of our sales and 28.0% of our gross profit in 2015, we seek to mitigate our exposure to fuel products margin volatility by maintaining a longer-term fuel products hedging program. Our entry into the oilfield services industry, which accounted for 6.7% of our sales and 9.7% of our gross profit in 2015, also contributes to our diversity of cash flows. In addition, our recent acquisitions of various refineries located in different geographic regions provides for diversity of cash flows based on the refining margin environment in each such region. We believe the diversity of our operating assets and products, our broad customer base and our hedging activities help contribute to the stability of our cash flows.
- Develop and Expand Our Customer Relationships. Due to the specialized nature of, and the long lead-time associated with, the development and production of many of our specialty products, our customers are incentivized to continue their relationships with us. We believe that our larger competitors do not work with customers as we do from product design to delivery for smaller volume specialty products like ours. We intend to continue to assist our existing customers in their efforts to expand their product offerings, as well as marketing specialty product formulations and services to new customers. By striving to maintain our long-term relationships with our broad base of existing customers and by adding new customers, we seek to limit our dependence on any one portion of our customer base.
- Enhance Profitability of Our Existing Assets. We continue to evaluate opportunities to improve our existing asset base, to increase our throughput, profitability and cash flows. Following each of our asset acquisitions, we have undertaken projects designed to maximize the profitability of our acquired assets, such as: (1) the enhancement at our Superior refinery completed in November 2012, which enables the refinery to ship crude oil by railcar to our other facilities as well as third party customers, (2) the enhancements at our San Antonio refinery completed in December 2013 allowed us to blend finished gasoline and increased its production capacity from 14,500 bpd to 18,000 bpd, (3) the enhancements at our San Antonio refinery completed in December 2015 allowed us to take a portion of the refinery's ultra-low sulfur diesel and jet fuel production and convert it into up to 3,000 bpd of higher margin solvents, (4) the more than doubling of esters production capacity at our Missouri facility completed in December 2015 and (5) the increase of production capacity at our Montana refinery from 10,000 bpd to 25,000 bpd, completed in February 2016. We intend to further increase the profitability of our existing asset base through various measures which may include changing the product mix of our processing units, debottlenecking and expanding units as necessary to increase throughput, restarting idle assets and reducing costs by improving operations. We also continue to focus on optimizing current operations through improving reliability, product quality enhancements, product yield improvements and energy saving initiatives.

- Pursue Strategic and Complementary Acquisitions. Our management team has demonstrated the ability to identify opportunities to acquire assets and product lines where we can enhance operations and improve profitability. In the future, we intend to continue to consider strategic acquisitions of assets or agreements with third parties that offer the opportunity for operational efficiencies, the potential for increased utilization and expansion of facilities, or the expansion of product offerings in each of our specialty products, fuel products and oilfield services segments. In addition, we may pursue selected acquisitions in new geographic or product areas to the extent we perceive similar opportunities. For example, since 2011 we have completed the following acquisitions that we believe significantly enhance and diversify our existing specialty products, fuel products and oilfield services segments:

Table of Contents

- Superior, Wisconsin, refinery ("Superior") — a refinery that produces and sells gasoline, diesel, asphalt and heavy fuel oils acquired in September 2011 ("Superior Acquisition").
- Calumet Packaging, LLC ("Calumet Packaging") — formerly known as TruSouth Oil, LLC, a specialty petroleum packaging and distribution company acquired in January 2012.
- Louisiana, Missouri, ("Missouri") facility — an aviation and refrigerant synthetic lubricants business acquired in January 2012.
- Royal Purple, Inc. ("Royal Purple") — a leading independent formulator and marketer of specialty synthetic lubricants and greases acquired in July 2012.
- Montana Refining Company, Inc. ("Montana") — a refinery that produces and sells gasoline, diesel, jet fuel and asphalt products acquired in October 2012.
- San Antonio, Texas, refinery ("San Antonio") — a refinery that produces and sells diesel, gasoline, jet fuel, other fuel products and solvents acquired in January 2013.
- Crude oil logistics assets — crude oil loading facilities and related assets in North Dakota and Montana acquired in August 2013.
- Bel-Ray Company, LLC ("Bel-Ray") — a manufacturer and global distributor of high-performance synthetic lubricants and greases acquired in December 2013.
- United Petroleum, LLC assets ("United Petroleum") — a marketer and distributor of high performance lubricants acquired in February 2014.
- ADF Holdings, Inc., the parent company of Anchor Drilling Fluids USA, Inc. ("Anchor Drilling Fluids") — an independent provider and marketer of drilling fluids and completion fluids to the oil and gas exploration industry acquired in March 2014.
- Specialty Oilfield Solutions, Ltd. assets ("Anchor Oilfield Services") — a full-service drilling fluids and solids control company with primary operations in the Eagle Ford, Marcellus and Utica shale formations acquired from Specialty Oilfield Services, Ltd. in August 2014.

Competitive Strengths

We believe that we are well positioned to execute our business strategies successfully based on the following competitive strengths:

- We Offer Our Customers a Diverse Range of Specialty Products. We offer a wide range of approximately 4,500 specialty products. We believe that our ability to provide our customers with a more diverse selection of products than most of our competitors gives us an advantage in competing for new business. We believe that we are the only specialty products manufacturer that produces all four of naphthenic lubricating oils, paraffinic lubricating oils, waxes and solvents. A contributing factor in our ability to produce numerous specialty products is our ability to ship products between our facilities for product upgrading in order to meet customer specifications.
- We Have Strong Relationships with a Broad Customer Base. We have long-term relationships with many of our customers and we believe that we will continue to benefit from these relationships. Our customer base includes more than 4,600 active accounts and we are continually seeking new customers. No single customer accounted for more than 10% of our consolidated sales in each of the three years ended December 31, 2015, 2014 and 2013.
- Our Facilities Have Advanced Technology. Our facilities are equipped with advanced, flexible technology that allows us to produce high-grade specialty products and to produce fuel products that comply with low sulfur fuel regulations. For example, our fuel products refineries have the capability to make ultra-low sulfur diesel and gasoline that meet federally mandated low sulfur standards and the Mobile Source Air Toxic Rule II standards ("MSAT II Standards") set by the EPA requiring the reduction of benzene levels in gasoline. Also, unlike larger refineries which lack some of the equipment necessary to achieve the narrow distillation ranges associated with the production of specialty products, our operations are capable of producing a wide range of products tailored to our customers' needs.
- We Have an Experienced Management Team. Our management has a proven track record of enhancing value through the acquisition, exploitation and integration of refining assets and the development and marketing of specialty products and services. Our senior management team has an average of over 25 years of industry experience. Our team's extensive experience and contacts within the refining industry provide a strong foundation and focus for

managing and enhancing our operations, accessing strategic acquisition opportunities and constructing and enhancing the profitability of new assets.

Table of Contents

Ongoing Acquisition Activities

Consistent with our business growth strategy, we are continuously engaged in discussions with potential sellers regarding the possible purchase of assets and operations that are strategic and complementary to our existing operations. These acquisition efforts may involve participation by us in processes that have been made public and involve a number of potential buyers, commonly referred to as “auction” processes, as well as situations in which we believe we are the only potential buyer or one of a limited number of potential buyers in negotiations with the potential seller. These acquisition efforts often involve assets and operations which, if acquired, could have a material effect on our financial condition and results of operations and require special financing.

We typically do not announce a transaction until we have executed a definitive acquisition agreement. However, in certain cases in order to protect our business interests or for other reasons, we may defer public announcement of an acquisition until closing or a later date. Past experience has demonstrated that discussions and negotiations regarding a potential acquisition can advance or terminate in a short period of time. Moreover, the closing of any transaction for which we have entered into a definitive acquisition agreement will be subject to customary and other closing conditions, which may not ultimately be satisfied or waived. Accordingly, we can give no assurance that our current or future acquisition efforts will be successful. Although we expect the acquisitions we make to be accretive in the long term, we can provide no assurance that our expectations will ultimately be realized.

Partnership Structure and Management

Calumet Specialty Products Partners, L.P. is a Delaware limited partnership formed on September 27, 2005. Our general partner is Calumet GP, LLC, a Delaware limited liability company. As of February 29, 2016, we have 75,884,400 common units and 1,548,660 general partner units outstanding. Our general partner owns 2% of the Company and all incentive distribution rights and has sole responsibility for conducting our business and managing our operations. For more information about our general partner’s board of directors and executive officers, please read Part III, Item 10 “Directors, Executive Officers of Our General Partner and Corporate Governance.”

Table of Contents

Our Operating Assets and Contractual Arrangements

General

The following table sets forth information about our combined operations, excluding the results of operations of our oilfield services segment. Facility production volume differs from sales volume due to changes in inventories and the sale of purchased fuel product blendstocks, such as ethanol and biodiesel, and the resale of crude oil in our fuel products segment. The table includes the results of operations at our San Antonio refinery commencing January 2, 2013, Bel-Ray facility commencing December 10, 2013 and United Petroleum assets commencing February 28, 2014:

	Year Ended December 31,			Year Ended December 31,		
	2015	2014	% Change	2014	2013	% Change
	(In bpd)			(In bpd)		
Total sales volume [1]	126,216	122,852	2.7 %	122,852	116,477	5.5 %
Total feedstock runs [2]	123,051	117,427	4.8 %	117,427	110,237	6.5 %
Facility production: [3]						
Specialty products:						
Lubricating oils	13,325	11,836	12.6 %	11,836	13,247	(10.7)%
Solvents	7,942	8,934	(11.1)%	8,934	8,759	2.0 %
Waxes	1,460	1,510	(3.3)%	1,510	1,443	4.6 %
Packaged and synthetic specialty products [4]	1,584	1,754	(9.7)%	1,754	1,481	18.4 %
Other	1,355	1,829	(25.9)%	1,829	2,192	(16.6)%
Total specialty products	25,666	25,863	(0.8)%	25,863	27,122	(4.6)%
Fuel products:						
Gasoline	37,691	34,221	10.1 %	34,221	29,374	16.5 %
Diesel	30,204	27,074	11.6 %	27,074	26,015	4.1 %
Jet fuel	5,157	4,799	7.5 %	4,799	4,105	16.9 %
Asphalt, heavy fuel oils and other	24,077	22,189	8.5 %	22,189	19,976	11.1 %
Total fuel products	97,129	88,283	10.0 %	88,283	79,470	11.1 %
Total facility production [3]	122,795	114,146	7.6 %	114,146	106,592	7.1 %

(1) Total sales volume includes sales from the production at our facilities and certain third-party facilities pursuant to supply and/or processing agreements, sales of inventories and the resale of crude oil to third party customers. Total sales volume includes the sale of purchased fuel product blendstocks, such as ethanol and biodiesel, as components of finished fuel products in our fuel products segment sales.

(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.

(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. The difference between total facility production and total feedstock runs is primarily a result of the time lag between the input of feedstocks and the production of finished products and volume loss.

(4) Represents production of packaged and synthetic specialty products, including the products from the Royal Purple, Bel-Ray, Calumet Packaging and Missouri facilities.

7

Table of Contents

The following table sets forth information about our combined sales of principal products and services by segment. The table includes the results of operations at our San Antonio refinery commencing January 2, 2013, at our Bel-Ray facility commencing December 10, 2013, United Petroleum assets commencing February 28, 2014, at Anchor Drilling Fluids commencing March 31, 2014, and at Anchor Oilfield Services commencing August 1, 2014:

	Year Ended December 31,								
	2015			2014			2013		
	(In millions)	% of Sales		(In millions)	% of Sales		(In millions)	% of Sales	
Sales of specialty products:									
Lubricating oils	$575.6	13.7	%	$748.4	12.9	%	$848.8	15.7	%
Solvents	302.0	7.2	%	485.2	8.4	%	511.7	9.4	%
Waxes	136.9	3.2	%	144.1	2.5	%	141.0	2.6	%
Packaged and synthetic specialty products [1]	316.6	7.5	%	313.5	5.4	%	233.6	4.3	%
Other [2]	36.7	0.9	%	38.0	0.7	%	39.8	0.7	%
Total	1,367.8	32.5	%	1,729.2	29.9	%	1,774.9	32.7	%
Sales of fuel products:									
Gasoline	1,047.1	24.9	%	1,443.1	24.9	%	1,409.4	26.0	%
Diesel	894.8	21.2	%	1,197.4	20.7	%	1,259.2	23.3	%
Jet fuel	149.6	3.6	%	199.3	3.4	%	191.4	3.5	%
Asphalt, heavy fuel oils and other [3]	471.0	11.1	%	853.6	14.7	%	786.5	14.5	%
Total	2,562.5	60.8	%	3,693.4	63.7	%	3,646.5	67.3	%
Sales of oilfield services:	282.5	6.7	%	368.5	6.4	%	—	—	
Consolidated sales	$4,212.8	100.0	%	$5,791.1	100.0	%	$5,421.4	100.0	%

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

(2) Represents by-products, including fuels and asphalt, produced in connection with the production of specialty products at the Princeton and Cotton Valley refineries and Dickinson and Karns City facilities.

(3) Represents asphalt, heavy fuel oils and other products produced in connection with the production of fuels at the Shreveport, Superior, San Antonio and Montana refineries and crude oil sales from the Superior and San Antonio refineries to third party customers.

Please read Note 17 "Segments and Related Information" in Part II, Item 8 "Financial Statements and Supplementary Data" of this Annual Report for additional financial information about each of our segments and the geographic areas in which we conduct business.

Shreveport Refinery

The Shreveport refinery, located on a 240 acre site in Shreveport, Louisiana ("Shreveport"), currently has aggregate crude oil throughput capacity of 60,000 bpd and processes paraffinic crude oil and associated feedstocks into fuel products, paraffinic lubricating oils, waxes, asphalt and by-products.

The Shreveport refinery consists of seventeen major processing units including hydrotreating, catalytic reforming and dewaxing units and approximately 3.3 million barrels of storage capacity in 130 storage tanks and related loading and unloading facilities and utilities. Since our acquisition of the Shreveport refinery in 2001, we have expanded the refinery's capabilities by adding additional processing and blending facilities, adding a second reactor to the high pressure hydrotreater, resuming production of gasoline, diesel and other fuel products and adding both 18,000 bpd of crude oil throughput capacity and the capability to run up to 25,000 bpd of sour crude oil with an expansion project completed in May 2008.

Table of Contents

The following table sets forth historical information about production at our Shreveport refinery:

	Shreveport Refinery		
	Year Ended December 31,		
	2015	2014	2013
	(In bpd)		
Crude oil throughput capacity	60,000	60,000	60,000
Total feedstock runs (1) (2)	40,726	35,140	36,178
Total refinery production (2) (3)	41,588	34,189	34,832

(1) Total feedstock runs represent the barrels per day of crude oil and other feedstocks processed at our Shreveport refinery. Total feedstock runs do not include certain interplant feedstocks supplied by our Cotton Valley, Princeton and San Antonio refineries.

(2) Total refinery production represents the barrels per day of specialty products and fuel products yielded from processing crude oil and other feedstocks. The difference between total refinery production and total feedstock runs is primarily a result of the time lag between the input of feedstocks and production of finished products and volume loss.

(3) Total refinery production includes certain interplant feedstock supplied to our Cotton Valley, Princeton and San Antonio refineries and Karns City facility.

The Shreveport refinery has a flexible operational configuration and operating personnel that facilitate development of new product opportunities. Product mix may fluctuate from one period to the next to capture market opportunities. The refinery has an idle residual fluid catalytic cracking unit, alkylation unit, vacuum tower and a number of idle towers that can be utilized for future project needs. Certain idle towers were utilized as a part of the Shreveport refinery expansion project completed in 2008.

The Shreveport refinery receives crude oil via tank truck, railcar and a common carrier pipeline system that is operated by a subsidiary of Plains All American Pipeline, L.P. (“Plains”) and is connected to the Shreveport refinery’s facilities. The Plains pipeline system delivers local supplies of crude oil and condensates from north Louisiana and east Texas. In November 2012, we completed an expansion project at our Superior refinery, which enabled the refinery to ship crude oil by railcar to our Shreveport refinery as well as to third party customers. Crude oil is also purchased from various suppliers, including local producers, who deliver crude oil to the Shreveport refinery via tank truck.

The Shreveport refinery also has direct pipeline access to the Enterprise Products Partners L.P. pipeline (“TEPPCO pipeline”), on which it can ship certain grades of gasoline, diesel and jet fuel. Further, the refinery has direct access to the Red River Terminal facility, which provides the refinery with barge access, via the Red River, to major feedstock and petroleum products logistics networks on the Mississippi River and Gulf Coast inland waterway system. The Shreveport refinery also ships its finished products throughout the U.S. through both truck and railcar service.

Superior Refinery

The Superior refinery is located on a 245 acre site, with an additional 430 acres owned around the existing refinery, in Superior, Wisconsin. The Superior refinery currently has aggregate crude oil throughput capacity of 45,000 bpd and processes light and heavy crude oil from the Bakken shale formation in North Dakota and western Canada into fuel products and asphalt.

The Superior refinery consists of fourteen major processing units including hydrotreating, catalytic reforming, fluid catalytic cracking and alkylation units and approximately 3.2 million barrels of storage capacity in 76 tanks and related loading and unloading facilities and utilities.

The following table sets forth historical information about production at our Superior refinery:

	Superior Refinery		
	Year Ended December 31,		
	2015	2014	2013
	(In bpd)		

Crude oil throughput capacity	45,000	45,000	45,000
Total feedstock runs [1] [2]	36,270	36,736	32,821
Total refinery production [2]	35,916	35,712	31,757

(1) Total feedstock runs represent the barrels per day of crude oil and other feedstocks processed at our Superior refinery.

(2) Total refinery production represents the barrels per day of fuel products yielded from processing crude oil. The difference between total refinery production and total feedstock runs is primarily a result of the time lag between the input of feedstocks and the production of finished products and volume loss.

The Superior refinery has a flexible operational configuration and operating personnel that facilitate development of new product opportunities. Product mix may fluctuate from one period to the next to capture market opportunities. Currently the Superior refinery produces gasoline, diesel, asphalt and heavy fuel oils.

Finished fuel products produced at the Superior refinery are sold through the Superior refinery truck rack, several Magellan pipeline terminals in Minnesota, Wisconsin, Iowa, North Dakota, South Dakota, and Utah and through our Duluth terminal. The Superior wholesale fuel business also sells gasoline wholesale to Calumet branded gas stations located throughout the Upper Midwest (including Minnesota, Wisconsin and Michigan), which are owned and operated by independent franchisees. The Superior refinery ships finished fuel products by railcar, truck and pipeline service. Asphalt products produced at the Superior refinery are shipped by railcar and truck service and are sold through our terminals in Rhinelander and Crookston and through other leased terminals in the U.S.

Finished fuel products sales are primarily made through spot agreements and short-term contracts. Asphalt is primarily sold through spot agreements and short-term contracts with customers primarily located in and around the Upper Midwest, North Dakota, South Dakota, Utah and New York.

The Superior refinery receives crude oil via pipeline. The Enbridge Pipeline delivers crude oil to the Superior refinery and is adjacent to one of the Enbridge Pipeline's first crude oil holding facilities after crossing the Canadian border into the U.S., providing reliable access to high quality crude oil from the Bakken shale formation in North Dakota and from western Canada. The refinery receives approximately 47% of its daily crude oil requirements under a crude oil purchase agreement (the "BP Purchase Agreement") with BP Products North America Inc. ("BP"). For more information about the BP Purchase Agreement, please read the information provided under Note 6 "Commitments and Contingencies" in Part II, Item 8 "Financial Statements and Supplementary Data" of this Annual Report. In November 2012, the Superior refinery completed an expansion project, which enables the refinery to ship crude oil by railcar to our Shreveport refinery as well as to third party customers.

Montana Refinery

The Montana refinery, located on an 86 acre site in Great Falls, Montana, currently has aggregate crude oil throughput capacity of 25,000 bpd and processes light and heavy crude oil from Canada into fuel and asphalt products. In February 2016, we completed an expansion project which added 15,000 bpd of feedstock throughput capacity to the refinery.

The Montana refinery consists of fifteen major processing units including hydrotreating, catalytic reforming, hydrocracking, fluid catalytic cracking and alkylation units, approximately 1.1 million barrels of storage capacity in 75 tanks and related loading and unloading facilities and utilities.

The following table sets forth historical information about production at the Montana refinery:

	Montana Refinery Year Ended December 31,		
	2015	2014	2013
	(In bpd)		
Crude oil throughput capacity	10,000	10,000	10,000
Total feedstock runs (1) (2)	10,307	10,201	9,290
Total refinery production (2)	10,525	10,274	9,015

(1) Total feedstock runs represent the barrels per day of crude oil and other feedstocks processed at our Montana refinery.

(2) Total refinery production represents the barrels per day of specialty products and fuel products yielded from processing crude oil and other feedstocks. The difference between total refinery production and total feedstock

runs is primarily a result of the time lag between the input of feedstocks and the production of finished products and volume loss.

Currently, the Montana refinery produces gasoline, diesel, jet fuel and asphalt products. The Montana refinery ships finished fuel and asphalt products by railcar and truck service. Finished fuel and asphalt products sales are primarily made through spot agreements and short-term contracts.

The Montana refinery purchases crude oil from various suppliers and receives crude oil by pipeline through the Front Range Pipeline via the Bow River Pipeline in Canada, providing reliable access to high quality crude oil from western Canada.

Table of Contents

In February 2016, we completed an expansion project that increased production capacity at our Montana refinery by 15,000 bpd to 25,000 bpd. This project allows us to capitalize on local access to cost-advantaged Bow River crude oil, while producing additional fuels and refined products for delivery into the regional market. The scope of this project included the installation of a new crude unit that can process up to 25,000 bpd of crude oil and other feedstocks, a hydrogen plant and a 20,000 bpd mild hydrocracker.

San Antonio Refinery

The San Antonio refinery, located on a 32 acre site in San Antonio, Texas, has aggregate crude oil throughput capacity of 21,000 bpd and processes light crude oil from south Texas, including the Eagle Ford shale formation, into a variety of transportation fuels, petrochemical and refinery feedstocks, and aliphatic solvents. The San Antonio refinery consists of six major processing units including crude fractionation, naphtha hydrotreating, catalytic reforming, distillate hydrotreating, aromatic saturation and specialty fractionation. The refinery has approximately 200,000 barrels of storage capacity in 65 tanks and related loading and unloading facilities and utilities.

Currently, the San Antonio refinery produces diesel, jet fuel, gasoline, other fuel products and a variety of aliphatic solvents. The San Antonio refinery is compliant with federal regulations for ultra-low sulfur diesel. The San Antonio refinery ships products by railcar and truck service. Product sales are primarily made through spot agreements and short-term contracts. The San Antonio refinery purchases crude oil and intermediate products from various suppliers and receives crude oil by pipeline originating from its crude oil terminal in Elmendorf, Texas (“Elmendorf”), providing reliable access to high quality crude oil from Texas, primarily the Eagle Ford shale formation. The San Antonio refinery has a 20-year agreement with TexStar Midstream Logistics, L.P. (“TexStar”) under which TexStar operates the Karnes North Pipeline System (“KNPS”), which transports crude oil from Karnes City, Texas, to Elmendorf. Currently, the San Antonio refinery receives at least 12,000 bpd of crude oil at the refinery through the KNPS-Elmendorf terminal supply route. Elmendorf has aggregate storage capacity of approximately 200,000 barrels.

Since acquiring the San Antonio refinery, we have expanded the refinery’s capabilities by adding 6,500 bpd of crude oil throughput capacity and adding additional processing and blending facilities which allow the San Antonio refinery to blend up to 6,000 bpd of finished gasoline. Additionally, we completed a project in December 2015 that allows us to take a portion of the San Antonio refinery’s diesel and jet fuel production and convert it into up to 3,000 bpd of higher margin solvent products that meet customer requirements for low aromatic content.

The following table sets forth historical information at our San Antonio refinery since our acquisition on January 2, 2013:

	San Antonio Refinery		
	Year Ended December 31,		
	2015	2014	2013
	(In bpd)		
Crude oil throughput capacity	21,000	17,500	17,500
Total feedstock runs (1) (2)	16,442	14,617	10,908
Total refinery production (2)	15,708	13,541	10,381

(1) Total feedstock runs represent the barrels per day of crude oil and other feedstocks processed at our San Antonio refinery from January 2, 2013, through December 31, 2015.

(2) Total refinery production represents the barrels per day of specialty products and fuel products yielded from processing crude oil and other feedstocks from January 2, 2013, through December 31, 2015. The difference between total refinery production and total feedstock runs is primarily a result of the time lag between the input of feedstocks and the production of finished products and volume loss.

Cotton Valley Refinery

The Cotton Valley refinery, located on a 77 acre site in Cotton Valley, Louisiana (“Cotton Valley”), currently has aggregate crude oil throughput capacity of 13,500 bpd, hydrotreating capacity of 6,200 bpd and processes crude oil into specialty solvents and residual fuel oil. The residual fuel oil is an important feedstock for the production of specialty products at our Shreveport refinery. We believe the Cotton Valley refinery produces the most complete, single-facility line of paraffinic solvents in the U.S.

Table of Contents

The Cotton Valley refinery consists of three major processing units that include a crude unit, a hydrotreater and a fractionation train, approximately 625,000 barrels of storage capacity in 74 storage tanks and related loading and unloading facilities and utilities. Since our acquisition of the Cotton Valley refinery in 1995, we have expanded the refinery's capabilities by installing a hydrotreater that removes aromatics, increased the crude unit processing capability to 13,500 bpd and reconfigured the refinery's fractionation train to improve product quality, enhance flexibility and lower utility costs.
The following table sets forth historical information about production at our Cotton Valley refinery:

	Cotton Valley Refinery		
	Year Ended December 31,		
	2015	2014	2013
	(In bpd)		
Crude oil throughput capacity	13,500	13,500	13,500
Total feedstock runs (1) (2)	6,413	6,580	5,667
Total refinery production (2) (3)	6,103	6,544	6,678

(1) Total feedstock runs do not include certain interplant solvent feedstocks supplied by our Shreveport refinery.
(2) Total refinery production represents the barrels per day of specialty products yielded from processing crude oil and other feedstocks. The difference between total refinery production and total feedstock runs is primarily a result of the time lag between the input of feedstocks and the production of finished products and volume loss.
(3) Total refinery production includes certain interplant feedstocks supplied to our Shreveport refinery.

The Cotton Valley refinery has a flexible operational configuration and operating personnel that facilitate development of new product opportunities. Product mix may fluctuate from one period to the next to capture market opportunities, which allows us to respond to market changes and customer demands by modifying the refinery's product mix. The reconfigured fractionation train also allows the refinery to satisfy demand fluctuations efficiently without large finished product inventory requirements.
The Cotton Valley refinery receives crude oil via tank truck. The Cotton Valley refinery's feedstock is primarily low sulfur and paraffinic crude oil originating from north Louisiana and is purchased from various marketers and gatherers. In addition, the Cotton Valley refinery receives interplant feedstocks for solvent production from the Shreveport refinery. The Cotton Valley refinery ships finished products by both truck and railcar service.

Princeton Refinery

The Princeton refinery, located on a 208 acre site in Princeton, Louisiana ("Princeton"), currently has aggregate crude oil throughput capacity of 10,000 bpd and processes naphthenic crude oil into lubricating oils, asphalt and feedstock for the Shreveport refinery for further processing into ultra-low sulfur diesel. The asphalt produced may be further processed or blended for coating and roofing product applications at the Princeton refinery or transported to the Shreveport refinery for further processing into bright stock.
The Princeton refinery consists of seven major processing units, approximately 650,000 barrels of storage capacity in 200 storage tanks and related loading and unloading facilities and utilities. Since our acquisition of the Princeton refinery in 1990, we have debottlenecked the crude unit to increase production capacity to 10,000 bpd, increased the hydrotreater's capacity to 7,000 bpd and upgraded the refinery's fractionation unit, which has enabled us to produce higher value specialty products.
The following table sets forth historical information about production at our Princeton refinery:

	Princeton Refinery		
	Year Ended December 31,		
	2015	2014	2013
	(In bpd)		
Crude oil throughput capacity	10,000	10,000	10,000
Total feedstock runs (1)	7,105	6,669	6,464
Total refinery production (1) (2)	5,851	5,420	5,313

(1) Total refinery production represents the barrels per day of specialty products yielded from processing crude oil and other feedstocks. The difference between total refinery production and total feedstock runs is primarily a result of the time lag between the input of feedstocks and the production of finished products and volume loss.

Table of Contents

(2) Total refinery production includes certain interplant feedstocks supplied to our Shreveport refinery.

The Princeton refinery has a hydrotreater and significant fractionation capability enabling the refining of high quality naphthenic lubricating oils at numerous distillation ranges. The Princeton refinery's processing capabilities consist of atmospheric and vacuum distillation, hydrotreating, asphalt oxidation processing and clay/acid treating. In addition, we have the necessary tankage and technology to process our asphalt into higher value product applications such as coatings, road paving and emulsions for road paving and specialty applications.

The Princeton refinery receives crude oil via tank truck, railcar and the Plains pipeline system. Its crude oil supply primarily originates from east Texas and north Louisiana, purchased directly from third-party suppliers under month-to-month evergreen supply contracts and on the spot market. The Princeton refinery ships its finished products throughout the U.S. via truck, barge and railcar service.

Missouri Facility

The Missouri facility, located on a 22 acre site in Louisiana, Missouri, develops and produces polyolester synthetic lubricants for use in refrigeration compressors, commercial aviation and polyolester base stocks. In December 2015, we completed a project to double the production capacity of the facility from 35 million pounds to 75 million pounds per year. The facility has approximately 178,000 barrels of storage capacity in 64 tanks and related loading and unloading facilities and utilities. The facility receives its fatty acids and alcohol feedstocks and additives by truck and railcar under supply agreements or spot agreements with various suppliers.

The Missouri facility utilizes the latest batch esterification processes designed to ensure blending accuracy while maintaining production flexibility to meet customer needs.

Royal Purple

The Royal Purple facility, located on a 28 acre site in Porter, Texas, develops, blends and packages high performance synthetic lubricants and fluid additive products for use in industrial, commercial and automotive applications. The Royal Purple facility's processing capability includes ten in-house packaging and production lines. Outsourced packaging services for specific products are also used. The facility has approximately 30,500 barrels of storage capacity in 91 tanks and related loading and unloading facilities. The facility receives its base oil feedstocks and additives by truck under supply agreements or spot agreements with various suppliers.

Bel-Ray

The Bel-Ray facility, located on a 32 acre site in Wall Township, New Jersey, blends and packages high performance synthetic lubricants and greases for use primarily in aerospace, automotive, energy, food, marine, military, mining, motorcycle, powersports, steel and textiles applications. The Bel-Ray facility's processing capability includes 24 blending tanks and packaging production lines. In addition, the Bel-Ray facility has approximately 13,000 barrels of storage capacity in 63 tanks and related loading and unloading facilities and utilities. The Bel-Ray facility receives its base oil feedstocks and additives by truck under supply agreements or spot agreements with various suppliers.

The Bel-Ray facility is designed with batch processing technology and is also designed to maximize blending flexibility to meet customer needs. The packaging operations utilize both in-house packaging equipment and outsourced packaging services for specific products.

Karns City and Dickinson Facilities and Other Processing Agreements

The Karns City facility, located on a 225 acre site in Karns City, Pennsylvania ("Karns City"), has aggregate base oil throughput capacity of 5,500 bpd and processes white mineral oils, solvents, petrolatums, gelled hydrocarbons, cable fillers and natural petroleum sulfonates. The Karns City facility's processing capability includes hydrotreating, fractionation, acid treating, filtering, blending and packaging. In addition, the facility has approximately 817,000 barrels of storage capacity in 250 tanks and related loading and unloading facilities and utilities.

The Dickinson facility, located on a 28 acre site in Dickinson, Texas ("Dickinson"), has aggregate base oil throughput capacity of 1,300 bpd and processes white mineral oils, compressor lubricants, natural petroleum sulfonates and biodiesel. The Dickinson facility's processing capability includes acid treating, filtering and blending, approximately 183,000 barrels of storage capacity in 186 tanks and related loading and unloading facilities and utilities.

These facilities each receive their base oil feedstocks by railcar and truck under supply agreements or spot purchases with various suppliers, the most significant of which is a long-term supply agreement with Phillips 66. Please read

"— Our Crude Oil and Feedstock Supply" below for further discussion of the long-term supply agreement with Phillips 66.

Table of Contents

The following table sets forth the combined historical information about production at our Karns City, Dickinson and other facilities:

	Combined Karns City, Dickinson and Other Facilities		
	Year Ended December 31,		
	2015	2014	2013
	(in bpd)		
Feedstock throughput capacity (1)	11,300	11,300	11,300
Total feedstock runs (2) (3)	5,515	6,651	7,250
Total production (3)	5,519	6,575	7,137

(1) Includes Karns City, Dickinson and other facilities.

(2) Includes feedstock runs at our Karns City and Dickinson facilities as well as throughput at certain third-party facilities pursuant to supply and/or processing agreements and includes certain interplant feedstocks supplied from our Shreveport refinery. For more information regarding our purchase commitments related to these supply and/or processing agreements, please read Part II, Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations — Contractual Obligations and Commitments."

(3) Total production represents the barrels per day of specialty products yielded from processing feedstocks at our Karns City and Dickinson facilities and certain third-party facilities pursuant to supply and/or processing agreements. The difference between total production and total feedstock runs is primarily a result of the time lag between the input of feedstocks and the production of finished products.

Anchor Drilling Fluids and Anchor Oilfield Services

We are an independent provider and marketer of drilling fluids and completion fluids to the oil and gas exploration industry. We design, manufacture and package drilling fluid products at our locations in Texas, Oklahoma, Louisiana, Arkansas, Colorado, Utah, Wyoming, Montana, New Mexico, New York, North Dakota, Pennsylvania and Ohio. We service oil and gas resource plays in North America, including the Bakken, Barnett, Eagle Ford, Fayetteville, Granite Wash, Haynesville, Marcellus, Niobrara, Permian, Piceance, Uinta and Utica shale formations.

We develop custom formulations and innovative solutions based on unique customer and well specifications. Through our extensive line of drilling and completion fluids, we deliver solutions that reduce drilling and completion time, help to control reservoir formation pressures and maximize oil and gas production, contributing to improved well economics for end-users.

Terminals

Our terminals are complementary to our refineries and play a key role in moving our products to end-user markets by providing services including distribution and blending to achieve specified products and storage and inventory management. We operate the following terminals:

Burnham Terminal: We own and operate a terminal located on an 11 acre site, in Burnham, Illinois. The Burnham terminal receives specialty products from certain of our refineries primarily by railcar and distributes them by truck and railcar to our customers in the Upper Midwest and East Coast regions of the U.S. and in Canada. The terminal includes a tank farm with 90 tanks having aggregate storage capacity of approximately 150,000 barrels, as well as blending equipment for producing engine oil additives and tackifiers.

Rhinelander Terminal: We own and operate a terminal located on an 18 acre site, in Rhinelander, Wisconsin. The Rhinelander terminal receives asphalt by truck from the Superior refinery and distributes product by truck. Asphalt from this terminal is sold to customers in the Upper Midwest region of the U.S. The terminal includes a tank farm with four tanks with aggregate storage capacity of approximately 166,000 barrels.

Crookston Terminal: We own and operate a terminal located on a 19 acre site, in Crookston, Minnesota. The Crookston terminal receives asphalt by truck from the Superior refinery and distributes product by truck. Asphalt from this terminal is sold to customers in the Upper Midwest region of the U.S. The terminal includes a tank farm with three tanks with aggregate storage capacity of approximately 156,000 barrels.

Duluth Terminal: We own and operate a terminal located on a 49 acre site, in Proctor, Minnesota. The Duluth terminal is supplied refined fuel products from the Superior refinery by the Magellan pipeline and receives ethanol and biodiesel products by truck. Fuel products from this terminal are distributed by truck to customers in Minnesota and northern Wisconsin. The terminal includes seven tanks with aggregate storage capacity of approximately 200,000 barrels.

Table of Contents

In addition to the above terminals, we own and lease additional facilities, primarily related to distribution of finished products, throughout the U.S.

Crude Oil Logistics Assets

We own and operate seven crude oil loading facilities and related assets in North Dakota and Montana, which provide us with the ability to transport crude oil directly from the point of lease into our crude oil loading facilities and then onto the Enbridge Pipeline where it can be routed to our Superior refinery and/or third party customers.

Other Logistics Assets

We use approximately 2,900 railcars leased from various lessors. This fleet of railcars enables us to receive and ship crude oil and distribute various specialty products and fuel products throughout the U.S. and Canada to and from each of our facilities.

Our Crude Oil and Feedstock Supply

We purchase crude oil and other feedstocks from major oil companies as well as from various crude oil gatherers and marketers in Texas, north Louisiana, North Dakota and Canada. Crude oil supplies at our refineries are as follows:

Refinery	Crude Oil Slate	Mode of Transportation
Shreveport	West Texas Intermediate (“WTI”), local crude oils from East Texas, North Louisiana, Arkansas and Light Louisiana Sweet (“LLS”)	Tank truck, railcar and Plains Pipeline
Superior	Canadian Heavy, Canadian Synthetic, North Dakota Sweet (e.g. Bakken) and Mixed Sweet Blend (“MSW”)	Enbridge Pipeline
San Antonio	Local Texas sweet crude oil (e.g. Eagle Ford)	Truck and pipeline connected to its Elmendorf crude oil terminal
Cotton Valley	Local paraffinic crude oil	Plains Pipeline and tank truck
Montana	Canadian Heavy and Canadian Sour (e.g. Bow River)	Front Range Pipeline
Princeton	Local naphthenic crude oil	Tank truck, railcar and Plains Pipeline

In 2015, subsidiaries of Plains supplied us with approximately 37.4% of our total crude oil supply under term contracts and month-to-month evergreen crude oil supply contracts. In 2015, BP supplied us with approximately 14.8% of our total crude oil supply under the BP Purchase Agreement. Each of our refineries is dependent on one or more key suppliers and the loss of any of these suppliers would adversely affect our financial results to the extent we were unable to find another supplier of this substantial amount of crude oil. For more information about the BP Purchase Agreement, please read the information provided under Note 6 “Commitments and Contingencies” in Part II, Item 8 “Financial Statements and Supplementary Data” of this Annual Report.

We do not maintain long-term contracts with most of our crude oil suppliers. For example, our contracts with Plains are currently month-to-month, terminable upon 90 days’ notice. In April 2012, we amended and restated the BP Purchase Agreement, which had an initial term of one year ending April 1, 2013, and automatically renews for successive one-year terms unless terminated by either party upon 90 days’ notice prior to the end of any renewal term. We also purchase foreign crude oil when its spot market price is attractive relative to the price of crude oil from domestic sources.

We have various long-term feedstock supply agreements with Phillips 66, with remaining terms ranging from one to two years, with some agreements operating under the option to continue on a month-to-month basis thereafter, for feedstocks that are key to the operations of our Karns City and Dickinson facilities. In addition, certain products of our refineries can be used as feedstocks by these facilities.

We believe that adequate supplies of crude oil and feedstocks will continue to be available to us.

Our cost to acquire crude oil and feedstocks and the prices for which we ultimately can sell refined products depend on a number of factors beyond our control, including regional and global supply of and demand for crude oil and other feedstocks and specialty and fuel products. These, in turn, are dependent upon, among other things, the availability of imports, overall economic conditions, production levels of domestic and foreign suppliers, U.S. relationships with foreign governments, political affairs and the extent of governmental regulation. We have historically been able to pass on the costs associated with increased crude oil and feedstock prices to our specialty products customers, although the increase in selling prices for specialty products typically lags a rising cost of crude oil. From time to time, we use a hedging program to manage a portion of our commodity price risk. Please read Part II, Item 7A "Quantitative and Qualitative Disclosures About Market Risk — Commodity Price Risk — Derivative Instruments" for a discussion of our hedging program.

Table of Contents

Our Products, Markets and Customers

Products

Specialty Products and Fuel Products. We produce a full line of specialty products, including lubricating oils, solvents, waxes, packaged and synthetic specialty products, other by-products, as well as a variety of fuel and fuel related products, asphalt and heavy fuel oils. Our customers purchase specialty products primarily as raw material components for basic industrial, consumer and automotive goods.

Oilfield Services. We are an independent provider and marketer of drilling fluids and completion fluids.

- Drilling fluids — Drilling fluids, often referred to as "drilling mud," are an essential and critical product of the drilling process for every oil and gas well. We provide three different types of drilling fluids including water-based mud, oil-based mud and synthetic-based mud.
- Completion fluids — Completion fluids replace drilling fluids during the final operations leading up to oil and gas production from a well. Completion fluids are critical products designed to control reservoir formation pressures and minimize formation damage in the event of a failure in down hole equipment.
- Solids control — Solids control is employed in drilling operations to filter out cuttings and clean the drilling fluid before it is pumped back into the well.

The following table depicts a representative sample of the diversity of end-use applications for the products we produce:

Representative Sample of End-Use Applications by Product

Lubricating Oils	Solvents	Waxes	Packaged and Synthetic Specialty Products	Oilfield Services	Other	Fuels & Fuel Related Products
14% (1)	7% (1)	3% (1)	7% (1)	7% (1)	1% (1)	61% (1)
• Hydraulic oils • Passenger car motor oils • Railroad engine oils • Cutting oils • Compressor oils • Metalworking fluids • Transformer oils • Rubber process oils • Industrial lubricants •	• Waterless hand cleaners • Alkyd resin diluents • Automotive products • Calibration fluids • Camping fuel • Charcoal lighter fluids • Chemical processing • Drilling fluids • Printing inks • Water treatment • Paint and coatings • Stains	• Paraffin waxes • FDA compliant products • Candles • Adhesives • Crayons • Floor care • PVC • Paint strippers • Skin & hair care • Timber treatment • Waterproofing • Pharmaceuticals • Cosmetics	• Refrigeration compressor oils • Positive displacement and roto-dynamic compressor oils • Commercial and military jet engine oil • Lubricating greases • Gear oils • Aviation hydraulic oils • High performance small engine fuels • Two cycle and four stroke engine oils • High performance automotive engine oils	• Drilling fluids • Completion fluids • Solids control	• Roofing • Paving	• Gasoline • Diesel • Jet fuel • Marine diesel fuel • Biodiesel • Ethanol • Ethanol free fuels • Fluid catalytic cracking feedstock • Asphalt vacuum residuals • Mixed butanes • Roofing • Paving • Heavy fuel oils

- Gear oils
- Grease
- Automatic transmission fluid
- Animal feed dedusting
- Baby oils
- Bakery pan oils
- Catalyst carriers
- Gelatin capsule lubricants
- Sunscreen

- High performance industrial lubricants
- High temperature chain lubricants
- Food contact grade lubricants
- Charcoal lighter fluids and other solvents
- Engine treatment additives

(1) Based on the percentage of total sales for the year ended December 31, 2015. Except for the listed fuel products and certain products sold by our Royal Purple, Bel-Ray and Calumet Packaging facilities and United Petroleum assets, we do not produce any of these end-use products.

Marketing

We have an experienced marketing department with average industry tenure of approximately 20 years. Our salespeople regularly visit customers, and our marketing department works closely with both the laboratories at our production facilities and our technical services department to help create specialized blends that will work optimally for our customers.

Table of Contents

Markets

Specialty Products. The specialty products market represents a small portion of the overall petroleum refining industry in the U.S. Of the nearly 140 refineries currently in operation in the U.S., only a small number of the refineries are considered specialty products producers and only a few compete with us in terms of the number of products produced. Our specialty products are utilized in applications across a broad range of industries, including:

- industrial goods such as metalworking fluids, belts, hoses, sealing systems, batteries, hot melt adhesives, pressure sensitive tapes, electrical transformers, refrigeration compressors and drilling fluids;
- consumer goods such as candles, petroleum jelly, creams, tonics, lotions, coating on paper cups, chewing gum base, automotive aftermarket car-care products (e.g., fuel injection cleaners, tire shines and polishes), lamp oils, charcoal lighter fluids, camping fuel and various aerosol products; and
- automotive goods such as motor oils, greases, transmission fluid and tires.

We have the capability to ship our specialty products worldwide. In the U.S., we ship our specialty products via railcars, trucks and barges. We use our fleet of approximately 2,900 leased railcars to ship our specialty products and a majority of our specialty products sales are shipped in trucks owned and operated by several different third-party carriers. For shipments outside of North America, which accounted for less than 10% of our consolidated sales in 2015, we ship via railcars and trucks to several ports where the product is loaded onto vessels for shipment to customers abroad.

Fuel Products. The fuel products market represents a large portion of the overall petroleum refining industry in the U.S. Of the nearly 140 refineries currently in operation in the U.S., a large number of the refineries are fuel products producers; however, only a few compete with us in our local markets.

Gulf Coast Market (PADD 3)

Fuel products produced at our Shreveport refinery can be sold locally or to the Midwest region of the U.S. through the TEPPCO pipeline. Local sales are made from the TEPPCO terminal in Bossier City, Louisiana, located approximately 15 miles from the Shreveport refinery, as well as from our own Shreveport refinery terminal.

Gasoline, diesel and jet fuel from the Shreveport refinery is sold primarily into the Louisiana, Texas and Arkansas markets, and any excess volumes are sold to marketers further up the TEPPCO pipeline. Should the appropriate market conditions arise, we have the capability to redirect and sell additional volumes into the Louisiana, Texas and Arkansas markets rather than transport them to the Midwest region via the TEPPCO pipeline.

The Shreveport refinery has the capacity to produce about 9,000 bpd of commercial jet fuel that can be marketed to the U.S. Department of Defense, sold as Jet-A locally or sold via the TEPPCO pipeline, or occasionally transferred to the Cotton Valley refinery to be processed further as a feedstock to produce solvents. We have a sales contract with the U.S. Department of Defense for approximately 2,500 bpd of jet fuel. This contract is effective until March 2016 and is bid annually.

Fuel products produced at our San Antonio refinery are sold locally in Texas. Additionally, the San Antonio refinery produces commercial and specialty jet fuel that can be marketed to the U.S. Department of Defense or sold locally as Jet-A fuel. We have a sales contract with the U.S. Department of Defense for approximately 550 bpd of jet fuel. This contract is effective until March 2017.

Additionally, we produce a number of fuel-related products including fluid catalytic cracking (“FCC”) feedstock, vacuum residuals and mixed butanes. FCC feedstock is sold to other refiners as a feedstock for their FCC units to make fuel products. Vacuum residuals are blended or processed further to make asphalt products. Volumes of vacuum residuals which we cannot process are sold locally into the fuel oil market or sold via railcar to other refiners. Mixed butanes are primarily available in the summer months and are primarily sold to local marketers. If the mixed butanes are not sold, they are blended into our gasoline production.

Upper Midwest Market (PADD 2)

Fuel products produced at our Superior refinery can be sold locally, in the Upper Midwest region of the U.S. and in Canada. The Superior wholesale business sells fuel products produced at the Superior refinery through several Magellan pipeline terminals in Minnesota, Wisconsin, Iowa, North Dakota, South Dakota, and Utah and through its own leased or owned product terminals located in Superior, Wisconsin, and Duluth, Minnesota. The Superior wholesale business also sells gasoline wholesale to Calumet branded gas stations throughout the Upper Midwest, which are owned and operated by independent franchisees.

Northwest Market (PADD 4)

Fuel products produced at our Montana refinery can be sold locally and in Idaho, North Dakota, Oregon, Utah, Wyoming and Canada. Seasonally, the Montana refinery transports fuel products to terminals in Washington.

Table of Contents

We have a sales contract with the U.S. Department of Defense for approximately 150 bpd of jet fuel. This contract is effective until September 2016.

Oilfield Services. We sell oilfield products and services in the Bakken, Barnett, Eagle Ford, Fayetteville, Granite Wash, Haynesville, Marcellus, Niobrara, Permian, Piceance, Uinta and Utica shale formations.

Customers

Specialty Products. We have a diverse customer base for our specialty products, with approximately 3,600 active accounts. Many of our customers are long-term customers who use our products in specialty applications, after an approval process ranging from six months to two years. No single customer in our specialty products segment accounted for 10% or greater of consolidated sales in each of the three years ended December 31, 2015, 2014 and 2013.

Fuel Products. We have a diverse customer base for our fuel products, with approximately 600 active accounts. Our diverse customer base includes wholesale distributors and retail chains. We are able to sell the majority of the fuel products we produce at the Shreveport refinery to the local markets of Louisiana, Texas and Arkansas. We also have the ability to ship additional fuel products from the Shreveport refinery to the Midwest region through the TEPPCO pipeline should the need arise. Additionally, we are able to sell the majority of the fuel products we produce at the Superior refinery to local markets in Minnesota and Wisconsin. We also have the ability to ship additional fuel products from the Superior refinery to the Upper Midwest region through the Magellan pipeline. The majority of our fuel products produced at our Montana refinery are sold to local markets in Montana and Idaho as well as in Canada. Fuel products produced at our San Antonio refinery are sold to local markets in Texas. No single customer in our fuel products segment represented 10% or greater of consolidated sales in each of the three years ended December 31, 2015, 2014 and 2013.

Oilfield Services. We have a diversified, established and unique customer base for our oilfield services, with approximately 400 active accounts. Our customers are companies operating in the domestic oil and gas exploration and production industry. No single customer in our oilfield services segment accounted for 10% or greater of consolidated sales in each of the two years ended December 31, 2015 and 2014.

Competition

Competition in our markets is from a combination of large, integrated petroleum companies, independent refiners, wax production companies and oilfield services companies. Many of our competitors are substantially larger than us and are engaged on a national or international basis in many segments of the petroleum products business, including exploration and production, refining, transportation and marketing. These competitors may have greater flexibility in responding to or absorbing market changes occurring in one or more of these business segments. We distinguish our competitors according to the products that they produce. Set forth below is a description of our significant competitors according to product category.

Naphthenic Lubricating Oils. Our primary competitors in producing naphthenic lubricating oils include Ergon Refining, Inc., Cross Oil Refining and Marketing, Inc., San Joaquin Refining Co., Inc. and Martin Midstream Partners L.P.

Paraffinic Lubricating Oils. Our primary competitors in producing paraffinic lubricating oils include ExxonMobil Corporation, Motiva Enterprises, LLC, Phillips 66, Petro-Canada, HollyFrontier Corporation, Chevron Corporation, Sonneborn Refined Products and Royal Dutch Shell plc.

Paraffin Waxes. Our primary competitors in producing paraffin waxes include ExxonMobil, HollyFrontier Corporation, The International Group Inc. and Sonneborn Refined Products.

Solvents. Our primary competitors in producing solvents include CITGO Petroleum Corporation, ExxonMobil Chemical, Phillips 66 and Royal Dutch Shell plc.

Packaged and Synthetic Specialty Products. Our primary competitors in retail and commercial packaged and synthetic specialty products include ExxonMobil (Mobil 1), Ashland, Inc. (Valvoline) and BP Lubricants, USA (Castrol). Our primary competitors in industrial packaged and synthetic specialty products include ExxonMobil Corporation, Royal Dutch Shell plc and Chevron.

Fuel Products and By-Products. Our primary competitors in producing fuel products in the local markets in which we operate include Delek US Holdings, Flint Hills Resources, Northern Tier Energy LP, ExxonMobil, Valero Energy Corporation, Phillips 66, Cenex, Alon USA and Marathon Petroleum Corporation.

Oilfield Services. Our primary competitors in servicing oilfields in the local markets in which we operate include Schlumberger, Halliburton, Baker Hughes, Newpark Resources and other regional competition.

Our ability to compete effectively depends on our responsiveness to customer needs and our ability to maintain competitive prices and product and service offerings. We believe that our flexibility and customer responsiveness differentiate us from many

Table of Contents

of our larger competitors. However, it is possible that new or existing competitors could enter the markets in which we operate, which could negatively affect our financial performance.

Governmental Regulation

From time to time, we are a party to certain claims and litigation incidental to our business, including claims made by various taxation and regulatory authorities, such as the EPA, various state environmental regulatory bodies, the Internal Revenue Service ("IRS"), various state and local departments of revenue and the federal Occupational Safety and Health Administration ("OSHA"), as the result of audits or reviews of our business. In addition, we have property, business interruption, general liability and various other insurance policies that may result in certain losses or expenditures being reimbursed to us.

Environmental and Occupational Health and Safety Matters

Environmental

We conduct crude oil and specialty hydrocarbon refining, blending and terminal operations in addition to providing oilfield services and products, which activities are subject to stringent federal, state, regional and local laws and regulations governing worker health and safety, the discharge of materials into the environment and environmental protection. These laws and regulations impose obligations that are applicable to our operations, such as requiring the acquisition of permits to conduct regulated activities, restricting the manner in which we 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 our operations. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil and criminal penalties; the imposition of investigatory, remedial or corrective action obligations or the corresponding incurrence of capital expenditures; the occurrence of delays in the permitting, development or expansion of projects; and the issuance of injunctive relief limiting or prohibiting our activities in a particular area. Moreover, certain of these laws impose joint and several, strict liability for costs required to remediate and restore sites where petroleum hydrocarbons, wastes or other materials have been disposed of or released. In addition, new laws and regulations, new interpretations of existing laws and regulations, increased governmental enforcement or other developments could significantly increase our operational or compliance expenditures, as discussed below in more detail.

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

San Antonio Refinery

In connection with the San Antonio Acquisition, we agreed to indemnify NuStar for an unlimited term and without consideration of a monetary deductible or cap from any environmental liabilities associated with the San Antonio refinery, except for any governmental penalties or fines that may result from NuStar's actions or inactions during NuStar's 20-month period of ownership of the San Antonio refinery. Anadarko Petroleum Corporation ("Anadarko") and Age Refining, Inc. ("Age Refining"), a third party that has since entered bankruptcy, are subject to a 1995 Agreed Order from the Texas Natural Resource Conservation Commission, now known as the Texas Commission on Environmental Quality, pursuant to which Anadarko and Age Refining are obligated to assess and remediate certain contamination at the San Antonio refinery that predates our acquisition of the facility. We do not expect this pre-existing contamination at the San Antonio refinery to have a material adverse effect on our financial position or results of operations.

Montana Refinery

In connection with the acquisition of the Montana refinery from Connacher Oil and Gas Limited ("Connacher"), we became a party to an existing 2002 Refinery Initiative Consent Decree (the "Montana Consent Decree") with the EPA and the Montana Department of Environmental Quality (the "MDEQ"). The material obligations imposed by the Montana Consent Decree have been completed. On September 27, 2012, Montana Refining Company, Inc. received a final Corrective Action Order on Consent, replacing the refinery's previously held hazardous waste permit. This

Corrective Action Order on Consent governs the investigation and remediation of contamination at the Montana refinery. We believe the majority of damages related to such contamination at the Montana refinery are covered by a contractual indemnity provided by HollyFrontier Corporation (“Holly”), the owner and operator of the Montana refinery prior to its acquisition by Connacher, under an asset purchase agreement between Holly and Connacher, pursuant to which Connacher acquired the Montana refinery. Under this asset purchase agreement, Holly agreed to indemnify Connacher and Montana Refining Company, Inc., subject to timely notification, certain conditions and certain monetary baskets and caps, for environmental conditions arising under Holly’s ownership and operation of the Montana refinery and existing as of the date of sale to Connacher. During 2014, Holly provided us a notice challenging our position that Holly is obligated to indemnify our remediation expenses for environmental conditions to the extent arising under Holly’s ownership and operation of the refinery and existing as of the date of sale to Connacher, which expenses totaled approximately $17.6 million as of December 31, 2015, of which $14.4 million was capitalized into the cost of our recently completed expansion project and $3.2 million was expensed. We continue to believe that Holly is responsible to indemnify us for these remediation expenses disputed by Holly, and on September 22, 2015, we initiated a lawsuit against Holly and the sellers of the Montana refinery that were party to the asset purchase agreement. On November 24, 2015, Holly and such sellers filed a motion to dismiss the case pending arbitration. We are opposing the motion. In the event we are unsuccessful, we will be responsible for those remediation expenses. We expect that we may incur some costs to remediate other environmental conditions at the Montana refinery; however, we believe at this time that these other costs we may incur will not be material to our financial position or results of operations.

Superior Refinery

In connection with the acquisition of the Superior refinery, we became a party to an existing Refinery Initiative Consent Decree ("Superior Consent Decree") with the EPA and the Wisconsin Department of Natural Resources ("WDNR") that applies, in part, to our Superior refinery. Under the Superior Consent Decree, we must complete certain reductions in air emissions at the Superior refinery as well as report upon certain emissions from the refinery to the EPA and the WDNR. We estimate costs of up to $4.0 million as of December 31, 2015, to make known equipment upgrades and conduct other discrete tasks in compliance with the Superior Consent Decree. Failure to perform these required tasks under the Superior Consent Decree could result in the imposition of stipulated penalties, which could be material. We are currently assessing certain past actions at the refinery for compliance with the terms of the Superior Consent Decree, which actions may be subject to stipulated penalties under the Superior Consent Decree but, in any event, we do not currently believe that the imposition of such penalties for those actions, should they be imposed, would be material. In addition, we are pursuing certain additional environmental and safety-related projects at the Superior refinery. Completion of these additional projects will result in us incurring costs, which could be substantial. We incurred approximately $0.7 million of costs in 2014 related to installing process equipment at the Superior refinery pursuant to the EPA fuel content regulations.

On June 29, 2012, the EPA issued a Finding of Violation/Notice of Violation to the Superior refinery, which included a proposed penalty amount of $0.1 million. This finding is in response to information that we provided to the EPA in response to an information request. The EPA alleges that the efficiency of the flares at the Superior refinery is lower than regulatory requirements. We are contesting the allegations and are in settlement discussions with the EPA to resolve this issue. We have not yet received formal action from the EPA. We do not believe that the resolution of these allegations will have a material adverse effect on our financial position or results of operations.

We are contractually indemnified by Murphy Oil Corporation ("Murphy Oil") under an asset purchase agreement between Murphy Oil and us for specified environmental liabilities arising from the operation of the Superior refinery including: (i) certain obligations arising out of the Superior Consent Decree (including payment of a civil penalty required under the Superior Consent Decree), (ii) certain liabilities arising in connection with Murphy Oil's transport of certain wastes and other materials to specified offsite real properties for disposal or recycling prior to the Superior Acquisition and (iii) certain liabilities for certain third party actions, suits or proceedings alleging exposure, prior to the Superior Acquisition, of an individual to wastes or other materials at the specified on-site real property, which wastes or other materials were spilled, released, emitted or otherwise discharged by Murphy Oil. We believe contractual indemnity by Murphy Oil for such specified environmental liabilities is unlimited in duration and not subject to any monetary deductibles or maximums. The amount of any damages payable by Murphy Oil pursuant to the contractual indemnities under the asset purchase agreement are net of any amount recoverable under an environmental insurance policy that we obtained in connection with the Superior Acquisition, which named Murphy Oil and us as insureds and covers environmental conditions existing at the Superior refinery prior to the Superior Acquisition.

Shreveport, Cotton Valley and Princeton Refineries

On December 23, 2010, we entered into a settlement agreement with the Louisiana Department of Environmental Quality ("LDEQ") under LDEQ's "Small Refinery and Single Site Refinery Initiative," covering the Shreveport, Princeton and Cotton Valley refineries. This settlement agreement became effective on January 31, 2012. The settlement agreement, termed the "Global Settlement," resolved alleged violations of the federal Clean Air Act and federal Clean

Water Act regulations that arose prior to December 23, 2010. Among other things, we agreed to complete beneficial environmental programs and implement emissions reduction projects at our Shreveport, Cotton Valley and Princeton refineries on an agreed-upon schedule. During 2015 and 2014, we incurred approximately $6.8 million and $0.6 million, respectively, of such expenditures and estimate additional expenditures of approximately $3.0 million to $5.0 million of capital expenditures and expenditures related to additional personnel and environmental studies through 2016 as a result of the implementation of these requirements. These capital investment requirements will be incorporated into our annual capital expenditures budget, and we do 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 our financial position or results of operations.

We are contractually indemnified by Shell Oil Company ("Shell"), as successor to Pennzoil-Quaker State Company, and Atlas Processing Company, under an asset purchase agreement between Shell and us, for specified environmental liabilities arising from the operations of the Shreveport refinery prior to our acquisition of the facility. We believe the contractual indemnity is unlimited in amount and duration, but requires us to contribute $1.0 million of the first $5.0 million of indemnified costs for certain of the specified environmental liabilities.

Bel-Ray Facility

Bel-Ray executed an Administrative Consent Order ("ACO") with the New Jersey Department of Environmental Protection, effective January 4, 1994, which required investigation and remediation of contamination at or emanating from the Bel-Ray facility. In 2000, Bel-Ray entered into a fixed price remediation contract with Weston Solutions ("Weston"), a large remediation contractor, whereby Weston agreed to be fully liable for the remediation of the soil and groundwater issues at the facility, including an offsite groundwater plume pursuant to the ACO ("Weston Agreement"). The Weston Agreement set up a trust fund to reimburse Weston, administered by Bel-Ray's environmental counsel. As of December 31, 2015, the trust fund contained approximately $0.8 million. In addition, Weston has remediation cost containment insurance, should Weston be unable to complete the work required under the Weston Agreement. In connection with the Bel-Ray Acquisition, we became a party to the Weston Agreement. Weston has been addressing the environmental issues at the Bel-Ray facility over time, and the next phase will address the groundwater issues, which extend offsite.

Air Emissions

Our operations are subject to the federal Clean Air Act, as amended ("CAA"), and comparable state and local laws. The CAA Amendments of 1990 require most industrial operations in the U.S. to incur capital expenditures to meet the air emission control standards that are developed and implemented by the EPA and state environmental agencies. Under the CAA, facilities that emit regulated air pollutants are subject to stringent regulations, including requirements to install various levels of control technology on sources of pollutants. In addition, in recent years, the petroleum refining sector has become subject to stringent federal regulations that impose maximum achievable control technology ("MACT") on refinery equipment emitting certain listed hazardous air pollutants. Some of our facilities have been included within the categories of sources regulated by MACT rules. Our refining and terminal operations that emit regulated air pollutants are also subject to air emissions permitting requirements that incorporate stringent control technology requirements for which we may incur significant capital expenditures. Any renewal of those air emissions permits or a need to modify existing or obtain new air emissions permits has the potential to delay the development of our projects. We can provide no assurance that future compliance with existing or any new laws, regulations or permit requirements will not have a material adverse effect on our business, financial position or results of operations. For example, on October 1, 2015, the EPA issued a final rule under the CAA that became effective on December 28, 2015, lowering the National Ambient Air Quality Standard ("NAAQS") for ground-level ozone to 70 parts per billion under both the primary and secondary standards to provide requisite protection of public health and welfare, respectively. Also, in December 2015, the EPA published a final rule that amends three refinery standards already in effect, imposing additional or, in some cases, new emission control requirements on subject refineries. The final rule requires, among other things, the monitoring of air concentrations of benzene around the refinery fence line perimeter and submittal of the fence line monitoring data to the EPA on a quarterly basis; upgraded emissions controls for storage tanks, including controls for smaller capacity storage vessels and storage vessels storing materials with lower vapor pressures than previously regulated; enhanced performance requirements for flares including the use of a minimum of three pollution prevention measures, continuous monitoring of flares and pressure release devices and analysis and remedy of flare release events; and compliance with emissions standards for delayed coking units. These final rules and any other future air emissions rulemakings could impact us by requiring installation of new emission controls on some of our equipment, resulting in longer permitting timelines, and significantly increasing our capital expenditures and operating costs, which could adversely impact our business.

The CAA authorizes the EPA to require modifications in the formulation of the refined transportation fuel products we manufacture in order to limit the emissions associated with the fuel product's final use. For example, in February 2000, the EPA published regulations limiting the sulfur content allowed in gasoline. These regulations, referred to as "Tier 2 Standards," required the phase-in of gasoline sulfur standards beginning in 2004, with special provisions for small refiners and for refiners serving those western U.S. states exhibiting lesser air quality problems. Similarly, the EPA published regulations that limit the sulfur content of highway diesel beginning in 2006 from its former level of

500 parts per million (“ppm”) to 15 ppm (the “ultra-low sulfur standard”). Our Shreveport, Superior, Montana and San Antonio refineries have implemented the sulfur standard with respect to produced gasoline and produced diesel meeting the ultra-low sulfur standard. In April 2014, the EPA published more stringent sulfur standards, referred to as “Tier 3 Standards,” including requiring that motor gasoline will not contain more than 10 ppm of sulfur on an annual average basis by January 1, 2017. Our Shreveport, Superior, Montana and San Antonio refineries will implement the 10 ppm sulfur standard with respect to produced gasoline by January 1, 2017, and we do not believe any remaining equipment upgrades at one or more of these refineries necessary to achieve the 10 ppm sulfur standard with respect to such produced gasoline will result in any material capital expenditures by us. In addition, we are required to meet the MSAT II Standards adopted by the EPA to reduce the benzene content of motor gasoline produced at our facilities. We have completed capital projects at our Shreveport, Superior, Montana and San Antonio refineries to comply with these fuel quality requirements.

The EPA has issued Renewable Fuel Standard (“RFS”) mandates, requiring refiners such as us to blend renewable fuels into the petroleum fuels they produce and sell in the U.S. We, and other refiners subject to RFS, may meet the RFS requirements by blending the necessary volumes of renewable transportation fuels produced by us or purchased from third parties. To the extent that refiners will not or cannot blend renewable fuels into the products they produce in the quantities required to satisfy their obligations under the RFS program, those refiners must purchase renewable credits, referred to as RINs, to maintain compliance. To the extent that we exceed the minimum volumetric requirements for blending of renewable transportation fuels, we generate our own RINs for which we have the option of retaining the RINs for current or future RFS compliance or selling those RINs on the open market.

Under the RFS program, the volume of renewable fuels that obligated parties are required to blend into their finished petroleum fuels increases annually over time until 2022. Our Shreveport, Superior, Montana and San Antonio refineries are normally subject to compliance with the RFS mandates. However, the RFS program further provides for a small refinery to be granted a temporary exemption from its annual mandated volume of renewable fuels if such refinery can demonstrate that compliance with those mandated volumes would cause the refinery to suffer disproportionate economic hardship. In October 2014, the EPA granted both the Shreveport and San Antonio refineries a "small refinery exemption" under the RFS for the 2013 calendar year. Under these 2013 exemptions granted by the EPA, both the Shreveport and San Antonio refineries are not subject to the requirements of RFS as an "obligated party" for fuels produced at these refineries between January 1, 2013, and December 31, 2013. As a result of the exemptions, our requirements to purchase RINs for 2013 compliance were reduced by approximately 39 million RINs. As a result of the exemptions, we sold approximately 31 million RINs for a gain of approximately $18.2 million during the fourth quarter of 2014.

On November 30, 2015, the EPA issued final multi-year volume mandates for 2014 to 2016. While these volume mandates are generally lower than the statutory mandates, they represent a slight increase over the volumes initially proposed by the EPA for this three-year period and such volume mandates could be increased in the future. We have reapplied for the small refinery exemption at selected refineries for the full year 2014 and are in the process of an assessment to determine which of our fuels refineries potentially could be eligible for economic hardship exemptions for the 2015 calendar year. While we received a small refinery exemption for the Shreveport and San Antonio refineries for 2013, there is no assurance that such an exemption will be obtained for either of these refineries for the 2014 year or in future years, which would result in the need for more RINs for the applicable calendar year. Our gross 2015 annual RINs obligation, which includes RINs that were required to be secured through either our own blending or through the purchase of RINs in the open market, was 99 million RINs for the 2015 calendar year.

On October 13, 2010, the EPA raised the maximum amount of ethanol content allowed under federal law from 10% to 15% for cars and light trucks manufactured since 2007, and on January 21, 2011, EPA extended the maximum allowable ethanol content of 15% to apply to cars and light trucks manufactured between 2001 and 2006. The maximum amount allowed under federal law currently remains at 10% ethanol for all other vehicles. EPA required that fuel and fuel additive manufacturers take certain steps before introducing gasoline containing 15% ethanol ("E15") into the market, including developing and obtaining EPA approval of a plan to minimize the potential for E15 to be used in vehicles and engines not covered by the partial waiver. EPA has taken several recent actions to authorize the introduction of E15 into the market, including approving, on June 15, 2012, the first plans to minimize the potential for E15 to be used in vehicles and engines not covered by the partial waiver, followed by approving, on February 7, 2013, a new blender pump configuration for general use by retail stations that wish to dispense E15 and gasoline containing 10% ethanol ("E10") from a common hose and nozzle. Existing laws and regulations could change, and the minimum volumes of renewable fuels that must be blended with refined petroleum fuels may increase. Because we do not produce renewable transportation fuels at all of our refineries, increasing the volume of renewable fuels that must be blended into our products displaces an increasing volume of our Shreveport, Superior, Montana and San Antonio refineries' fuel products pool, potentially resulting in lower earnings and materially adversely affecting our ability to make payments on our debt obligations.

Climate Change

In response to findings by the EPA that emissions of carbon dioxide, methane and other greenhouse gases ("GHG") present an endangerment to public health and the environment because emissions of such gases are contributing to the warming of the earth's atmosphere and other climatic changes, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, establish Prevention of Significant Deterioration ("PSD") construction and Title V operating permit program requiring reviews for GHG emissions from certain large stationary sources. Facilities required to obtain PSD permits for their GHG emissions will also be required to meet "best available control technology" standards, which will be established by the states or, in some instances, by the EPA on a case-by-case basis. Moreover, on December 23, 2010, the EPA entered a settlement agreement with environmental groups requiring the agency to propose by December 10, 2011, GHG New Source Performance Standards ("NSPS") for refineries and to finalize these rules by November 15, 2012. To date, the EPA has not completed those rulemakings, and we do not know when they will be completed. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified large GHG emission sources in the U.S., including petroleum refineries, on an annual basis. We monitor for and report upon GHG emissions at our facilities, where required. These EPA policies and rulemakings or any new administrative legal requirements could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities.

Table of Contents

In addition, from time to time Congress has considered legislation to reduce emissions of GHG, and a number of the states have already taken legal measures to reduce emissions of GHG, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. On an international level, the U.S. is one of almost 200 nations that agreed on December 12, 2015, to an international climate change agreement in Paris, France, that calls for countries to set their own GHG emissions targets and be transparent about the measures each country will use to achieve its GHG emissions targets. It is not possible at this time to predict how or when the U.S. might impose legal requirements as a result of this international agreement. The adoption of any legislation or regulations that requires reporting of GHG or otherwise limits emissions of GHG from our equipment and operations could require us to incur costs to reduce emissions of GHG associated with our operations or could adversely affect demand for the refined petroleum products that we produce. For example, on August 18, 2015, the EPA published a proposed rule that will establish emission standards for methane and volatile organic compounds released from new and modified oil and natural gas production and natural gas processing and transmissions facilities, as part of President Obama's Administration's efforts to reduce methane emissions from the oil and natural gas sector by up to 45 percent from 2012 levels by 2025. The EPA is expected to finalize those rules in 2016. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHG in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our operations.

Hazardous Substances and Wastes

The Comprehensive Environmental Response, Compensation and Liability Act, as amended ("CERCLA"), also known as the "Superfund" law, and comparable state laws impose liability without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. Such classes of persons include the current and past owners and operators of sites where a hazardous substance was released and companies that disposed or arranged for disposal of hazardous substances at offsite locations, such as landfills. Under CERCLA, these "responsible persons" may be subject to joint and several, strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances into the environment. In the course of our operations, we generate wastes or handle substances that may be regulated as hazardous substances, and we could become subject to liability under CERCLA and comparable state laws.

We also may incur liability under the Resource Conservation and Recovery Act, as amended ("RCRA"), and comparable state laws, which impose requirements related to the handling, storage, treatment and disposal of hazardous and non-hazardous wastes. In the course of our operations, we generate petroleum product wastes and ordinary industrial wastes, such as paint wastes, waste solvents and waste oils that may be regulated as hazardous wastes. In addition, our operations also generate non-hazardous solid wastes, which are regulated under RCRA and state laws. Historically, our environmental compliance costs under the existing requirements of RCRA and similar state and local laws have not had a material adverse effect on our results of operations, and the cost involved in complying with these requirements is not material.

We currently own or operate, and have in the past owned or operated, properties that for many years have been used for refining and terminal activities. These properties have in the past been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons and wastes were not under our control. Although we used operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or wastes have been released on or under the properties owned or operated by us. These properties and the materials disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes or property contamination or to perform remedial activities to prevent future contamination.

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, in 2012, the EPA published final amendments to the NSPS for petroleum refineries, including standards for emissions of nitrogen oxides from process heaters and work practice standards and monitoring requirements for flares.

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

Water Discharges

The Federal Water Pollution Control Act of 1972, as amended, also known as the federal Clean Water Act, and analogous state laws impose restrictions and stringent controls on the discharge of pollutants, including oil, into federal and state waters. Such discharges are prohibited, except in accordance with the terms of a permit issued by the EPA or the appropriate state agencies. Any unpermitted release of pollutants, including crude oil or hydrocarbon specialty oils as well as refined products, could result in penalties, as well as significant remedial obligations. Spill prevention, control, and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture, or leak. The EPA retains jurisdiction over federal waters of the U.S. pursuant to the Clean Water Act and has published a final rule on June 29, 2015, that attempted to clarify this jurisdiction over such waters of the U.S.; however, this rule is alleged to have impermissibly broadened such jurisdiction and thus the rule is subject to various legal impediments, including formalized opposition, lawsuits and/or court stays. Historically, our environmental compliance costs under the existing requirements of the federal Clean Water Act and similar state laws have not had a material adverse effect on our results of operations.

The primary federal law for oil spill liability is the Oil Pollution Act of 1990, as amended ("OPA"), which addresses three principal areas of oil pollution — prevention, containment and cleanup. OPA applies to vessels, offshore facilities and onshore facilities, including refineries, terminals and associated facilities that may affect waters of the U.S. Under OPA, responsible parties, including owners and operators of onshore facilities, may be subject to oil cleanup costs and natural resource damages as well as a variety of public and private damages from oil spills. Our past environmental compliance with OPA and similar state laws have not had a material adverse effect on our results of operations.

Occupational Health and Safety

We are 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 our operations and that this information be provided to employees, contractors, state and local government authorities and customers. We maintain safety and training programs as part of our ongoing efforts to ensure compliance with applicable laws and regulations. We conduct periodic audits of Process Safety Management ("PSM") systems at each of our locations subject to the PSM standard. Our compliance with applicable health and safety laws and regulations has required, and continues to require, substantial expenditures. Changes in occupational safety and health laws and regulations or a finding of non-compliance with current laws and regulations could result in additional capital expenditures or operating expenses, as well as civil penalties and, in the event of a serious injury or fatality, criminal charges.

We have completed studies to assess the adequacy of our PSM practices at our Shreveport refinery with respect to certain consensus codes and standards. During the years ended December 31, 2015 and 2014, we incurred approximately \$0.6 million and \$1.1 million, respectively, of related capital expenditures and expect to incur up to \$1.4 million of capital expenditures during 2016 to address OSHA compliance issues identified in these studies. We expect these capital expenditures will enhance our equipment such that the equipment maintains compliance with applicable consensus codes and standards.

In the first quarter of 2011, OSHA conducted an inspection of the Cotton Valley refinery's PSM program. On March 14, 2011, OSHA issued a Citation and Notification of Penalty (the "Cotton Valley Citation") to us as a result of our Cotton Valley inspection, which included a proposed penalty amount of \$0.2 million. We have contested the Cotton Valley Citation and have reached a tentative settlement with OSHA on the matter, which we do not believe will have a material adverse effect on our financial position or results of operations.

Other Environmental and Maintenance Items

We perform preventive and normal maintenance on most, if not all, of our refining and terminal assets and make repairs and replacements when necessary or appropriate. We also conduct inspections of these assets as required by law or regulation.

Insurance

Our operations are subject to certain hazards of operations, including fire, explosion and weather-related perils. We maintain insurance policies, including business interruption insurance for each of our facilities, with insurers in amounts and with coverage and deductibles that we, with the advice of our insurance advisors and brokers, believe are reasonable and prudent. We cannot, however, ensure that this insurance will be adequate to protect us from all material expenses related to potential future claims for personal and property damage or that these levels of insurance will be available in the future at economical prices. We are not fully insured against certain risks because such risks are not fully insurable, coverage is unavailable, or premium costs, in our judgment, do not justify such expenditures.

Table of Contents

Seasonality

The operating results for the fuel products segment, including the selling prices of asphalt products we produce, generally follow seasonal demand trends. Asphalt demand is generally lower in the first and fourth quarters of the year, as compared to the second and third quarters, due to the seasonality of the road construction and roofing industries we supply. Demand for gasoline and diesel is generally higher during the summer months than during the winter months due to seasonal increases in highway traffic. In addition, our natural gas costs can be higher during the winter months, as demand for natural gas as a heating fuel increases during the winter. As a result, our operating results for the first and fourth calendar quarters may be lower than those for the second and third calendar quarters of each year due to seasonality related to these and other products that we produce and sell.

The operating results for the oilfield services segment follow seasonal changes in weather and significant weather events can temporarily affect the performance and delivery of our oilfield services and products. The severity and duration of the winter can have a significant impact on drilling activity. Additionally, customer spending patterns for other oilfield services and products can result in lower activity in the fourth calendar quarter.

Properties

We own and lease the principal properties which are listed below. The principal properties which we own, among others not listed below, are pledged as collateral under our Collateral Trust Agreement as discussed in Part II, Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Debt and Credit Facilities.” We believe that all properties are suitable for their intended purpose, are being efficiently utilized and provide adequate capacity to meet demand for the next several years.

Property	Business Segment(s)	Acres	Owned / Leased	Location
Shreveport refinery	Fuels and Specialty	240	Owned	Shreveport, Louisiana
Superior refinery	Fuels	675	Owned	Superior, Wisconsin
Montana refinery	Fuels	86	Owned	Great Falls, Montana
San Antonio refinery	Fuels and Specialty	32	Owned	San Antonio, Texas
Princeton refinery	Specialty	208	Owned	Princeton, Louisiana
Cotton Valley refinery	Specialty	77	Owned	Cotton Valley, Louisiana
Burnham terminal	Specialty	11	Owned	Burnham, Illinois
Karns City facility	Specialty	225	Owned	Karns City, Pennsylvania
Dickinson facility	Specialty	28	Owned	Dickinson, Texas
Rhinelander terminal	Fuels	18	Owned	Rhinelander, Wisconsin
Crookston terminal	Fuels	19	Owned	Crookston, Minnesota
Missouri facility	Specialty	22	Owned	Louisiana, Missouri
Calumet Packaging facility	Specialty	10	Leased	Shreveport, Louisiana
Royal Purple facility	Specialty	28	Owned	Porter, Texas
Bel-Ray facility	Specialty	32	Owned	Wall Township, New Jersey
Elmendorf terminal	Fuels	8	Owned	Elmendorf, Texas
Duluth terminal	Fuels	49	Owned	Proctor, Minnesota

In addition to the items listed above, we lease or own a number of storage tanks, railcars, warehouses, equipment, land, crude oil loading facilities and precious metals.

Intellectual Property

Our patents relating to our refining operations are not material to us as a whole. Our products consist of composition patents which are integral to the formulas of our products. We own, have registered or applied for registration of a variety of tradenames, service marks and trademarks for us in our business. The trademarks, tradenames and design marks under which we conduct our branded business (including Royal Purple, Bel-Ray, TruFuel and Quantum) and other trademarks employed in the marketing of our products are integral to our marketing operations. We also license intellectual property rights from third parties. We are not aware of any facts as of the date of this filing which would negatively impact our continuing use of our tradenames, service marks or trademarks.

Office Facilities

In addition to our principal properties discussed above, as of December 31, 2015, we were a party to a number of cancelable and noncancelable leases for certain properties, including our corporate headquarters in Indianapolis, Indiana, and administrative offices in Houston, Texas. The corporate headquarters lease is for 58,501 square feet of office space. The lease term expires in

Table of Contents

August 2024. The Houston facility lease is for 24,025 square feet of office space. The lease term expires in August 2022. See Note 6 “Commitments and Contingencies” in Part II, Item 8 “Financial Statements and Supplementary Data — Notes to Consolidated Financial Statements” of this Annual Report for additional information regarding our leases.
While we may require additional office space as our business expands, we believe that our existing facilities are adequate to meet our needs for the immediate future and that additional facilities will be available on commercially reasonable terms as needed.

Employees

As of February 29, 2016, our general partner employs approximately 2,100 people who provide direct support to our operations. Of these employees, approximately 600 are covered by collective bargaining agreements.
Employees at the following locations are covered by the following separate collective bargaining agreements:

Facility/ Refinery	Union	Expiration Date
Superior	International Union of Operating Engineers	June 30, 2017
Cotton Valley	International Union of Operating Engineers	March 31, 2016
Princeton	International Union of Operating Engineers	October 31, 2017
Dickinson	International Union of Operating Engineers	March 31, 2016
Shreveport	United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied-Industrial and Service Workers International Union	April 30, 2016
Missouri	United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied-Industrial and Service Workers International Union	April 30, 2016
Karns City	United Steel, Paper and Forestry, Rubber, Manufacturing, Energy Allied-Industrial and Service Workers International Union	January 31, 2019
Montana	United Steel, Paper and Forestry, Rubber, Manufacturing, Energy Allied-Industrial and Service Workers International Union	January 31, 2019

None of the employees at the San Antonio refinery, Calumet Packaging facility, Royal Purple facility, Bel-Ray facility, Anchor or SOS locations or at the Burnham, Rhinelander, Crookston, Duluth or Elmendorf terminals are covered by collective bargaining agreements. Our general partner considers its employee relations to be good, with no history of work stoppages.

Address, Internet Website and Availability of Public Filings

Our principal executive offices are located at 2780 Waterfront Parkway East Drive, Suite 200, Indianapolis, Indiana, 46214 and our telephone number is (317) 328-5660. Our website is located at http://www.calumetspecialty.com.
Our Securities and Exchange Commission (“SEC”) filings are available on our website as soon as reasonably practicable after we electronically file such material with, or furnish such material to, the SEC. We make available, free of charge on our website, our Annual Reports on Form 10-K, our Quarterly Reports on Form 10-Q, our Current Reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). These documents are located on our website at http://www.calumetspecialty.com by selecting the “Investor Relations” link and then selecting the “SEC Filings” link. We also make available, free of charge on our website, our Charters for the Audit, Compensation and Conflicts Committees, Related Party Transactions Policy and Code of Business Conduct and Ethics. These documents are located on our website at http://www.calumetspecialty.com by selecting the “Investor Relations” link and then selecting the “Corporate Governance” link.
The above information is available to anyone who requests it and is free of charge either in print from our website or upon request by contacting Investor Relations using the contact information listed above. Information on our website is not incorporated into this Annual Report or our other securities filings and is not a part of them.
All reports and documents filed with the SEC are also available via the SEC website, http://www.sec.gov, or may be read and copied at the SEC Public Reference Room at 100 F Street, NE, Washington, D.C., 20549. Information on the operation of the SEC Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330.

26

Table of Contents

Item 1A. Risk Factors

Risks Relating to our Business

We may not have sufficient cash from operations to enable us to pay our distribution at the current distribution level, or at all, following the establishment of cash reserves and payment of fees and expenses, including payments to our general partner , and as a result , future distributions to our unitholders may be reduced, suspended or eliminated.

We may not have sufficient available cash from operations each quarter to enable us to pay our distribution to unitholders. Under the terms of our partnership agreement, we must pay expenses, including payments to our general partner, and set aside any cash reserve amounts before making a distribution to our unitholders. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which is primarily dependent upon our producing and selling quantities of fuel products, specialty products, or refined products, and oilfield services at margins that are high enough to cover our fixed and variable expenses. Crude oil costs, fuel and specialty products prices and, accordingly, the cash we generate from operations, will fluctuate from quarter to quarter based on, among other things:

- overall demand for specialty hydrocarbon products, fuel and other refined products;
- overall demand for oilfield products and services;
- the level of foreign and domestic production of crude oil and refined products;
- our ability to produce fuel products, specialty products and products used in oilfield services that meet our customers' unique and precise specifications;
- the marketing of alternative and competing products;
- the extent of government regulation;
- results of our hedging activities; and
- overall economic and local market conditions.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, some of which are beyond our control, including:

- the level of capital expenditures we make, including those for acquisitions, if any;
- our debt service requirements;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets;
- restrictions on distributions and on our ability to make working capital borrowings for distributions contained in our debt instruments; and
- the amount of cash reserves established by our general partner for the proper conduct of our business.

If we generate insufficient cash from our operations for a sustained period of time and/or forecasts demonstrate expectations of continued future insufficiencies, our board of directors may determine to reduce, suspend or eliminate our distribution to unitholders. Any such reduction, suspension or elimination in distributions may cause the trading price of our units to decline.

Refining margins are volatile, and a reduction in our refining margins will adversely affect the amount of cash we will have available for distribution to our unitholders and for payments of our debt obligations.

Our financial results are primarily affected by the relationship, or margin, between our specialty products prices and fuel products prices and the prices for crude oil and other feedstocks. The cost to acquire our feedstocks and the price at which we can ultimately sell our refined products depend upon numerous factors beyond our control. Historically, refining margins have been volatile, and they are likely to continue to be volatile in the future.

A widely used benchmark in the fuel products industry to measure market values and margins is the Gulf Coast 2/1/1 crack spread ("Gulf Coast crack spread"), which represents the approximate gross margin resulting from refining crude oil, assuming that two barrels of a benchmark crude oil are converted, or cracked, into one barrel of gasoline and one barrel of heating oil. The Gulf Coast crack spread ranged from a high of $28.74 per barrel to a low of $8.30 per barrel during 2015 and averaged $17.96 per barrel during 2015 compared to an average of $17.13 in 2014 and $21.57 in 2013.

Our actual refining margins vary from the Gulf Coast crack spread due to the actual crude oil used and products produced, transportation costs, regional differences, and the timing of the purchase of the feedstock and sale of the refined products, but we use the Gulf Coast crack spread as an indicator of the volatility and general levels of refining margins.

Table of Contents

The prices at which we sell specialty products are strongly influenced by the commodity price of crude oil. If crude oil prices increase, our specialty products segment margins will fall unless we are able to pass through these price increases to our customers. Increases in selling prices for specialty products typically lag behind the rising cost of crude oil and may be difficult to implement quickly enough when crude oil costs increase dramatically over a short period of time. For example, in the first six months of 2008, excluding the effects of hedges, we experienced a 31.3% increase in the cost of crude oil per barrel as compared to an 18.3% increase in the average sales price per barrel of our specialty products. It is possible we may not be able to pass through all or any portion of increased crude oil costs to our customers. In addition, we are not able to completely eliminate our commodity risk through our hedging activities. Because refining margins are volatile, unitholders should not assume that our current margins will be sustained. If our refining margins fall, it will adversely affect the amount of cash we will have available for distribution to our unitholders.

Our hedging activities may not be effective in reducing the volatility of our cash flows and may reduce our earnings, profitability and cash flows.

We are exposed to fluctuations in the price of crude oil, fuel products, natural gas and interest rates. From time to time, we utilize derivative financial instruments related to the future price of crude oil, natural gas, fuel products and their relationship with each other with the intent of reducing volatility in our cash flows due to fluctuations in commodity prices and spreads. Historically, we have utilized derivative instruments related to interest rates for future periods with the intent of reducing volatility in our cash flows due to fluctuations in interest rates. We are not able to enter into derivative financial instruments to reduce the volatility of the prices of the specialty products we sell as there is no established derivative market for such products.

The extent of our commodity price exposure is related largely to the effectiveness and scope of our hedging activities. The derivative instruments we utilize are based on posted market prices, which may differ significantly from the actual crude oil prices, natural gas prices or fuel products prices that we incur or realize in our operations. For example, excluding our crude oil basis swaps, all of the crude oil derivatives in our hedge portfolio are based on the market price of New York Mercantile Exchange (“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 Light Louisiana Sweet, Western Canadian Select and Brent, on which a portion of our crude oil purchases are priced) has changed period to period, which has reduced the effectiveness of certain crude oil hedges. Accordingly, our commodity price risk management policy may not protect us from significant and sustained increases in crude oil or natural gas prices or decreases in fuel products prices. Conversely, our policy may limit our ability to realize cash flows from crude oil and natural gas price decreases.

We have a policy to enter into derivative transactions related to only a portion of the volume of our expected purchase and sales requirements and, as a result, we will continue to have direct commodity price exposure to the unhedged portion of our expected purchase and sales requirements. Thus, we could be exposed to significant crude oil cost increases on a portion of our purchases. Please read Part II, Item 7A “Quantitative and Qualitative Disclosures About Market Risk.”

Our actual future purchase and sales requirements may be significantly higher or lower than we estimate at the time we enter into derivative transactions for such period. If the actual amount is higher than we estimate, we will have greater commodity price exposure than we intended. If the actual amount is lower than the amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale or purchase of the underlying physical commodity, which may result in a substantial diminution of our liquidity. As a result, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows. In addition, our hedging activities are subject to the risks that a counterparty may not perform its obligations under the applicable derivative instrument, the terms of the derivative instruments are imperfect, and our hedging policies and procedures are not properly followed. It is possible that the steps we take to monitor our derivative financial instruments may not detect and prevent violations of our risk management policies and procedures, particularly if deception or other intentional misconduct is involved.

Our financing arrangements contain operating and financial provisions that restrict our business and financing activities.

The operating and financial restrictions and covenants in our financing arrangements, including our revolving credit facility, indentures governing each series of our outstanding senior notes and master derivative contracts, do currently restrict, and any future financing agreements could restrict, our ability to finance future operations or capital needs or to engage, expand or pursue our business activities, including restrictions on our ability to, among other things:

- sell assets, including equity interests in our subsidiaries;
- pay distributions or redeem or repurchase our units or repurchase our subordinated debt;
- incur or guarantee additional indebtedness or issue preferred units;
- create or incur certain liens;
- make certain acquisitions and investments;

- redeem or repay other debt or make other restricted payments;
- enter into transactions with affiliates;
- enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us;
- create unrestricted subsidiaries;
- enter into sale and leaseback transactions;
- enter into a merger, consolidation or transfer or sale of assets, including equity interests in our subsidiaries; and
- engage in certain business activities.

Our revolving credit facility also contains a springing financial covenant which provides that, if availability under the revolving credit facility falls below the greater of (a) 12.5% of the Borrowing Base (as defined in the revolving credit agreement) then in effect and (b) $45.0 million, then we will be required to maintain as of the end of each fiscal quarter a Fixed Charge Coverage Ratio (as defined in the revolving credit agreement) of at least 1.0 to 1.0.

Our existing indebtedness imposes, and any future indebtedness may impose, a number of covenants on us regarding collateral maintenance and insurance maintenance. As a result of these covenants and restrictions, we will be limited in the manner in which we conduct our business, and we may be unable to engage in favorable business activities or finance future operations or capital needs.

Our ability to comply with the covenants and restrictions contained in our financing arrangements may be affected by events beyond our control. If market or other economic conditions deteriorate, our ability to comply with these covenants and restrictions may be impaired. A failure to comply with the covenants, ratios or tests in our financing arrangements or any future indebtedness could result in an event of default under these financing arrangements, which, if not cured or waived, could have a material adverse effect on our business, financial condition and results of operations. Among other things, in the event of any default on our indebtedness, our debt holders and lenders:

- will not be required to lend any additional amounts to us;
- could elect to declare all borrowings outstanding, together with accrued and unpaid interest and fees, to be due and payable;
- could elect to require that all obligations accrue interest at the default rate, if such rate has not already been imposed;
- may have the ability to require us to apply all of our available cash to repay these borrowings;
- may prevent us from making debt service payments under our other agreements, any of which could result in an event of default under our other financing arrangements; or
- in the case of our revolving credit facility, foreclose on the collateral pledged pursuant to the terms of the revolving credit facility.

If our existing indebtedness were to be accelerated, there can be no assurance that we would have, or be able to obtain, sufficient funds to repay such indebtedness in full. Even if new financing were available, it may be on terms that are less attractive to us than our then existing indebtedness or it may not be on terms that are acceptable to us. In addition, our obligations under our revolving credit facility are secured by a first priority lien on our cash, accounts receivable, inventory and certain other personal property and our obligations under our master derivative contracts are secured by a first priority lien on our 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 forgoing (including proceeds of hedge agreements), and if we are unable to repay our indebtedness under the revolving credit facility or master derivative contracts, the lenders under our revolving credit facility and the counterparties to our master derivative contracts could seek to foreclose on these assets. Please read Part II, Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Debt and Credit Facilities,” “— Short Term Liquidity,” “— Long-Term Financing,” and “— Master Derivative Contracts” for additional information regarding our long-term debt.

Our debt levels may limit our flexibility in obtaining additional financing and in pursuing other business opportunities.

We had approximately $1.8 billion of outstanding indebtedness as of December 31, 2015, and availability for borrowings of $233.5 million under our senior secured revolving credit facility. We continue to have the ability to incur additional debt, including the ability to borrow up to an aggregate principal amount of $1.0 billion at any time outstanding, subject to borrowing base limitations, under our revolving credit facility. Our level of indebtedness could have important consequences to us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;

- covenants contained in our existing and future credit and debt arrangements will require us to meet financial tests that may affect our flexibility in planning for and reacting to changes in our business, including possible acquisition opportunities;
- we will need a substantial portion of our cash flow to make principal and interest payments on our indebtedness, reducing the funds that would otherwise be available for operations, future business opportunities and payments of our debt obligations; and
- our debt level will make us more vulnerable than our competitors with less debt to competitive pressures or a downturn in our business or the economy generally.

Our ability to service our indebtedness will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service our current or future indebtedness, we will be forced to take actions such as reducing distributions to our unitholders, reducing or delaying our business activities, acquisitions, investments and/or capital expenditures, selling assets, restructuring or refinancing our indebtedness, or seeking additional equity capital or bankruptcy protection. We may not be able to effect any of these remedies on satisfactory terms, or at all. Please read Part II, Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Debt and Credit Facilities" for additional information regarding our indebtedness.

Decreases in the price of crude oil may lead to a reduction in the borrowing base under our revolving credit facility and our ability to issue letters of credit or the requirement that we post substantial amounts of cash collateral for derivative instruments, which could adversely affect our liquidity, financial condition and our ability to distribute cash to our unitholders.

We rely on borrowings and letters of credit under our revolving credit agreement to purchase crude oil or other feedstocks for our facilities, lease certain precious metals for use in our refinery operations and enter into derivative instruments of crude oil and natural gas purchases and fuel products sales. From time to time, we also rely on our ability to issue letters of credit to enter into certain hedging arrangements in an effort to reduce our exposure to adverse fluctuations in the prices of crude oil, natural gas and crack spreads. The borrowing base under our revolving credit facility is determined weekly or monthly depending upon availability levels or the existence of a default or event of default. Reductions in the value of our inventories as a result of lower crude oil prices could result in a reduction in our borrowing base, which would reduce the amount of financial resources available to meet our capital requirements. If, under certain circumstances, our available capacity under our revolving credit facility falls below certain threshold amounts, or a default or event of default exists, then our cash balances in a dominion account established with the administrative agent will be applied on a daily basis to our outstanding obligations under our revolving credit facility. In addition, decreases in the price of crude oil or increases in crack spreads may require us to post substantial amounts of cash collateral to our hedging counterparties in order to maintain our derivative instruments. If, due to our financial condition or other reasons, the borrowing base under our revolving credit facility decreases, we are limited in our ability to issue letters of credit or we are required to post substantial amounts of cash collateral to our hedging counterparties, our liquidity, financial condition and our ability to distribute cash to our unitholders could be materially and adversely affected. Please read Part II, Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Debt and Credit Facilities" for additional information.

We depend on certain key crude oil and other feedstock suppliers for a significant portion of our supply of crude oil and other feedstocks, and the loss of any of these key suppliers or a material decrease in the supply of crude oil and other feedstocks generally available to our facilities could materially reduce our ability to make distributions to unitholders.

We purchase crude oil and other feedstocks from major oil companies as well as from various crude oil gatherers and marketers primarily in Texas, north Louisiana, North Dakota and Canada. In 2015, subsidiaries of Plains supplied us with approximately 37.4% of our total crude oil supplies under term contracts and month-to-month evergreen crude oil supply contracts. In 2015, BP supplied us with approximately 14.8% of our total crude oil supplies under the BP

Purchase Agreement. Each of our facilities is dependent on one or more of these suppliers and the loss of any of these suppliers would adversely affect our financial results to the extent we were unable to find another supplier of this substantial amount of crude oil. We do not maintain long-term contracts with most of our suppliers. For example, our contracts with Plains are currently month-to-month and terminable upon 90 days' notice and our contract with BP automatically renewed in April 2015 for a one year term and will continue to automatically renew for successive one-year terms unless terminated by either party upon 90 days' notice.

We purchase all of our crude oil supply directly from third-party suppliers, generally under month-to-month evergreen supply contracts and on the spot market. Evergreen contracts are generally terminable upon 30 days' notice and purchases on the spot market may expose us to changes in commodity prices. For additional discussion regarding our crude oil and feedstock supply, please read Items 1 and 2 "Business and Properties — Our Crude Oil and Feedstock Supply."

To the extent that our suppliers reduce the volumes of crude oil and other feedstocks that they supply us as a result of declining production or competition or otherwise, our sales, net income and cash available for distribution to unitholders and payments of our debt obligations would decline unless we were able to acquire comparable supplies of crude oil and other feedstocks on comparable terms from other suppliers, which may not be possible in areas where the supplier that reduces its volumes is the primary supplier in the area. Fluctuations in crude oil prices can greatly affect production rates and investments by third parties in the development of new oil reserves. Drilling activity generally decreases as crude oil prices decrease. We have no control over the level of drilling activity in the fields that supply our refineries, the amount of reserves underlying the wells in these fields, the rate at which production from a well will decline or the production decisions of producers. A material decrease in either the crude oil production from or the drilling activity in the fields that supply our refineries, as a result of depressed commodity prices, natural gas production declines, governmental moratoriums on drilling or production activities, the availability and the cost of capital or otherwise, could result in a decline in the volume of crude oil we refine.

Trends in crude oil and natural gas prices affect the level of exploration, development, and production activity of our customers and the demand for our oilfield services and products, which could adversely affect the amount of cash we will have available for distribution to our unitholders and for payments of our debt obligations.

Demand for our oilfield services and products is particularly sensitive to the level of exploration, development and production activity of, and the corresponding capital spending by, crude oil and natural gas companies. The level of exploration, development, and production activity is directly affected by trends in oil and natural gas prices, which historically have been volatile and are likely to continue to be volatile.

Prices for crude oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for crude oil and natural gas, market uncertainty and a variety of other economic factors that are beyond our control. Any prolonged reduction in crude oil and natural gas prices will depress the immediate levels of exploration, development and production activity which could adversely affect the amount of cash we will have available for distribution to our unitholders and for payments of our debt obligations. Even the perception of longer-term lower crude oil and natural gas prices by oil and natural gas companies can similarly reduce or defer major expenditures given the long-term nature of many large-scale development projects. Factors affecting the prices of crude oil and natural gas include:

- the level of supply and demand for crude oil and natural gas, especially demand for natural gas in the U.S.;
- governmental regulations, including the policies of governments regarding the exploration for and production and development of their oil and natural gas reserves;
- weather conditions and natural disasters;
- worldwide political, military, and economic conditions;
- the level of crude oil production by non-Organization of the Petroleum Exporting Countries (“OPEC”) countries and the available excess production capacity within OPEC;
- crude oil refining capacity and shifts in end-customer preferences toward fuel efficiency and the use of natural gas;
- the cost of producing and delivering crude oil and natural gas; and
- potential acceleration of the development of alternative fuels.

During 2015, the oil and natural gas industry experienced a significant decrease in commodity prices driven by a global supply/demand imbalance for oil and an oversupply of natural gas in the United States. The decline in commodity prices and the global economic conditions have continued into 2016 and low commodity prices may exist for an extended period. If commodity prices continue to decline or remain depressed, there could be a material adverse effect on our business, financial condition and results of operations.

We depend on certain third-party pipelines for transportation of crude oil and refined fuel products, and if these pipelines become unavailable to us, our revenues and cash available for distributions to our unitholders and payment of our debt obligations could decline.

Our Shreveport refinery is interconnected to a pipeline that supplies a portion of its crude oil and a pipeline that ships a portion of its refined fuel products to customers, such as pipelines operated by subsidiaries of Enterprise Products Partners L.P. and Plains All American Pipeline, L.P. Our Superior refinery receives crude oil through the Enbridge Pipeline and the Superior wholesale business transports products produced at the Superior refinery through several Magellan pipeline terminals in Minnesota, Wisconsin, Iowa, North Dakota and South Dakota. Our Montana refinery receives crude oil through the Front Range pipeline system via the Bow River Pipeline in Canada. Our San Antonio refinery receives crude oil through the Karnes North Pipeline System in Texas. Since we do not own or operate any of these pipelines, their continuing operation is not within our control. In addition, any of these third-party pipelines could become unavailable to transport crude oil or our refined fuel products because of acts of God, accidents, earthquakes or hurricanes, government regulation, terrorism or other third-party events. For example, our refinery run rates were affected by an approximately three-week shutdown during May and June 2011 of the ExxonMobil crude oil pipeline serving our Shreveport refinery resulting from the Mississippi River flooding occurring during this period. In addition, ExxonMobil shut down this pipeline on April 28, 2012, after a leak was discovered. Also, on June 20, 2012, excessive flooding caused our Superior refinery to reduce its run rate to approximately half its usual throughput for one day and shut down the portion of the Magellan pipeline that connects our Superior refinery to our Duluth terminal for one day. The unavailability of any of these third-party pipelines for the transportation of crude oil or our refined fuel products, because of acts of God, accidents, earthquakes or hurricanes, government regulation, terrorism or other third-party events, could lead to disputes or litigation with certain of our suppliers or a decline in our sales, net income and cash available for distributions to our unitholders and payments of our debt obligations.

The price volatility of fuel and utility services may result in decreases in our earnings, profitability and cash flows.

The volatility in costs of fuel, principally natural gas, and other utility services, principally electricity, used by our refinery and other operations affect our net income and cash flows. Fuel and utility prices are affected by factors outside of our control, such as supply and demand for fuel and utility services in both local and regional markets. Natural gas prices have historically been volatile.

For example, daily prices for natural gas as reported on the NYMEX ranged between \$3.23 and \$1.76 per million British thermal unit (“MMBtu”), in 2015 and between \$6.15 and \$2.89 per MMBtu in 2014. Typically, electricity prices fluctuate with natural gas prices. Future increases in fuel and utility prices may have a material adverse effect on our results of operations. Fuel and utility costs constituted approximately 11.5% and 15.3% of our total operating expenses included in cost of sales for the years ended December 31, 2015 and 2014, respectively. If our natural gas costs rise, it will adversely affect the amount of cash available for distribution to our unitholders.

Our refineries, blending and packaging sites, terminals and related facility operations face operating hazards, and the potential limits on insurance coverage could expose us to potentially significant liability costs.

Our refineries, blending and packaging sites, terminals and related facility operations are subject to certain operating hazards, and our cash flow from those operations could decline if any of our facilities experiences a major accident, pipeline rupture or spill, explosion or fire, is damaged by severe weather or other natural disaster, or otherwise is forced to curtail its operations or shut down. For example, in 2010, our Shreveport refinery experienced an explosion that caused us to shut down one of this refinery’s environmental operating units between February and August 2010 when it was replaced with a newly constructed unit, resulting in modified operations during the interim period, including lower throughput rates at certain times during this period. These operating hazards could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in significant curtailment or suspension of our related operations.

Although we maintain insurance policies, including personal and property damage and business interruption insurance for each of our facilities with insurers in amounts and with coverage and deductibles that we, with the advice of our insurance advisors and brokers, believe are reasonable and prudent, we cannot ensure that this insurance will be adequate to protect us from all material expenses related to potential future claims for personal and property damage or significant interruption of operations. Our business interruption insurance will not apply unless a business interruption exceeds 60 days. Furthermore, we may be unable to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for certain of our insurance policies have increased and could escalate further. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. In addition, we are not fully insured against all risks incident to our business because certain risks are not fully insurable, coverage is unavailable, or premium costs, in our judgment, do not justify such expenditures. For example, we are not insured for all environmental liabilities, including, for example, product spills and other releases at all of our facilities. If we were to incur a significant liability for which we were not fully insured, it could diminish our ability to make distributions to our unitholders.

We may incur significant environmental costs and liabilities in the operation of our refineries, terminals and related facilities and performance of our oilfield service activities.

The operation of our refineries, blending and packaging sites, terminals, and related facilities as well as performance of our oilfield service activities subject us to the risk of incurring significant environmental costs and liabilities due to our handling of petroleum hydrocarbons and wastes, because of air emissions and water discharges related to our operations and activities, and as a result of historical operations and waste disposal practices at our facilities or in connection with our activities, some of which may have been conducted by prior owners or operators. We currently own, operate or conduct oilfield services upon properties that for many years have been used for industrial or oilfield activities, including refining and blending operations or terminal storage operations, sometimes by third parties over whom we had or continue to have no control with respect to their operations or waste disposal activities. Petroleum hydrocarbons or wastes have been released on, under or from the properties owned or operated by us. For example, we are investigating and remediating, in some cases pursuant to government order, soil and groundwater contamination at our Montana refinery arising from a predecessor operators' handling of petroleum hydrocarbons and wastes.

While we believe our costs in pursuing these investigatory and remedial activities are subject to reimbursement under a contractual indemnification we received from the predecessor operator in the share purchase agreement transferring ownership of this refinery, this predecessor operator is currently disputing responsibility for reimbursement of certain of these remedial costs being incurred at our Montana refinery, which dispute has resulted in the filing of a suit by us against the predecessor operator and may ultimately result in contractual-mandated mediation between the parties pursuant to the share purchase agreement. Joint and several, strict liability may be incurred in connection with releases of petroleum hydrocarbons and wastes on, under or from our properties and facilities. Neither the owners of our general partner nor their affiliates have indemnified us for any environmental liabilities, including those arising from non-compliance or pollution that may be discovered at, or arise from operations on, the assets they contributed to us in connection with the closing of our initial public offering. Private parties, including the owners of properties adjacent to our operations and facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal or the owners of properties where we conduct oilfield services, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. We may not be able to recover some or any of these costs from insurance or other sources of indemnity. To the extent that the costs associated with meeting any or all of these requirements are significant and not adequately secured or indemnified for, there could be a material adverse effect on our business, financial condition, and results of operations.

We are subject to compliance with stringent environmental and occupational health and safety laws and regulations that may expose us to significant costs and liabilities.

Our refining, blending and packaging site, terminal and related facility operations as well as our oilfield service activities are subject to stringent federal, regional, state and local laws and regulations governing worker health and safety, the discharge of materials into the environment and environmental protection. These laws and regulations impose numerous obligations that are applicable to our operations, including the obligation to obtain permits to conduct regulated activities, the incurrence of significant capital expenditures for air pollution control equipment to otherwise limit or prevent releases of pollutants from our refineries, blending and packaging sites, terminals, and related facilities or with respect to our oilfield services, the expenditure of significant monies in the application of specific health and safety criteria addressing worker protection, the requirement to maintain information about hazardous materials used or produced in our operations and oilfield services and to provide this information to employees, state and local government authorities, and local residents and the incurrence of significant costs and liabilities for pollution resulting from our operations and oilfield services or from those of prior owners or operators of our facilities. Numerous federal governmental authorities, such as the EPA and OSHA as well as state agencies, such as the LDEQ, TCEQ, MDEQ and the WDNR have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly actions. Failure to comply with these laws and regulations as well as any issued permits and orders may result in the assessment of administrative, civil, and criminal sanctions, including monetary penalties, the imposition of remedial obligations or corrective actions, and the issuance of injunctions limiting or preventing some or all of our operations.

On occasion, we receive notices of violation, other enforcement proceedings and regulatory inquiries from governmental agencies alleging non-compliance with applicable environmental and occupational health and safety laws and regulations. For example, we have pending proceedings with the LDEQ involving a series of alleged unauthorized emissions of pollutants from equipment at the Shreveport refinery, as described in a draft “Consolidated Compliance Order and Notice of Potential Penalty” issued in April 2013, for which a penalty of more than $0.1 million may result. In a further example, we have a pending proceeding with the EPA involving alleged unauthorized emissions of pollutants from flares at the Superior Refinery, as described in a “Notice of Violation” issued by the EPA on or around June 29, 2012, which included a proposed penalty amount of $0.1 million.

New worker safety and environmental 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. For example, in 2012, the EPA issued final amendments to the

NSPS for petroleum refineries, including standards for emissions of nitrogen oxides from process heaters and work practice standards and monitoring requirements for flares. In another example, in April 2014, the EPA published its final Tier 3 fuel standards that require, among other things, a lower allowable sulfur level in gasoline to no more than 10 ppm by January 1, 2017. In two other examples, on October 1, 2015, the EPA issued a final rule under the CAA lowering the NAAQS for ground-level ozone to 70 parts per billion under both the primary and secondary standards, and on June 29, 2015, the EPA published a final rule that attempted to clarify the agency’s jurisdiction over waters of the U.S., but which rule is currently subject to various legal impediments, including lawsuits and court stays, as this rule is alleged to have impermissibly broadened the EPA’s jurisdiction over such waters. One or more of these regulatory initiatives or any new environmental laws or regulations could impact us by requiring installation of new emission controls on some of our equipment, resulting in longer permitting timelines, and significantly increasing our capital expenditures and operating costs, which could adversely impact our business, cash flows and results of operation. Please read Items 1 and 2 “Business and Properties — Environmental and Occupational Health and Safety Matters” for additional information.

Table of Contents

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

The EPA has issued RFS mandates, requiring refiners such as us to blend renewable fuels into the petroleum fuels they produce and sell in the U.S. We, and other refiners subject to RFS, may meet the RFS requirements by blending the necessary volumes of renewable transportation fuels produced by us or purchased from third parties. To the extent that refiners will not or cannot blend renewable fuels into the products they produce in the quantities required to satisfy their obligations under the RFS program, those refiners must purchase renewable credits, referred to as RINs, to maintain compliance. To the extent that we exceed the minimum volumetric requirements for blending of renewable transportation fuels, we generate our own RINs for which we have the option of retaining the RINs for current or future RFS compliance or selling those RINs on the open market.

Under RFS, the volume of renewable fuels that obligated parties are required to blend into their finished petroleum fuels increases annually over time until 2022. Our Shreveport, Superior, Montana and San Antonio refineries are nominally subject to compliance with the RFS mandates. However, in October 2014, the EPA granted both our Shreveport and San Antonio refineries a “small refinery exemption” under the RFS for the 2013 calendar year, as provided under the CAA. Under these 2013 exemptions granted by the EPA, both our Shreveport and San Antonio refineries are not subject to the requirements of RFS as an “obligated party” for fuels produced at these refineries between January 1, 2013 and December 31, 2013. As a result of the exemptions, our requirements to purchase RINs for 2013 compliance were reduced by approximately 39 million RINs. As result of the exemptions, we sold approximately 31 million RINs during the fourth quarter 2014, generating cash of approximately $14.5 million and resulting in an $18.2 million gain.

On November 30, 2015, the EPA issued final multi-year volume mandates for 2014 to 2016. While these volume mandates are generally lower than the statutory mandates, they represent a slight increase over the volumes initially proposed by the EPA for this three-year period and such volume mandates could be increased in the future. We have reapplied for the small refinery exemption at selected refineries for the full year 2014 and are in the process of an assessment to determine which of our fuels refineries potentially could be eligible for economic hardship exemptions for the 2015 calendar year. While we received a small refinery exemption for the Shreveport and San Antonio refineries for 2013, there is no assurance that such an exemption will be obtained for either of these refineries for the 2014 year or in future years, which would result in the need for more RINs for the applicable calendar year. Our gross 2015 annual RINs obligation, which includes RINs that were required to be secured through either our own blending or through the purchase of RINs in the open market, was 99 million RINs for the 2015 calendar year.

Existing laws, regulations or regulatory initiatives could change and, notwithstanding that the EPA’s volume mandates for 2014 may be relatively lower than the statutory mandates, they represent a slight increase over the volumes initially proposed by the EPA for this three-year period and such volume mandates could be increased in the future. Because we do not produce renewable transportation fuels at all of our refineries, increasing the volume of renewable fuels that must be blended into our produces displaces an increase volume of our Shreveport, Superior, Montana and San Antonio refineries’ fuel products pool, potentially resulting in lower earnings and materially adversely affecting our ability to make distributions to our unitholders. Moreover, despite a decline in RINs prices from levels during mid-2013, we cannot currently predict the future prices of RINs and, thus, the expenses related to acquiring RINs in the future could increase relative to the cost in prior years. The inability to receive an exemption under the RFS program for one or more of our refineries, any increase in the final minimum volumes renewable fuels that must be blended with refined petroleum fuels, and/or any increase in the cost to acquire RINs may, individually or in the aggregate, have the potential to result in significant costs in connection with RIN compliance, which costs could be material. Finally, while there is no current regulatory standard that authenticates RINs that may be purchased on the open market from third parties, we believe that the RINs we purchase are from reputable sources, are valid and serve to demonstrate compliance with applicable RFS requirements. However, if any such RINs purchased by us on the open market are subsequently found to be invalid, then we may incur significant costs, penalties or other liabilities in connection with replacing such invalid RINs.

Downtime for maintenance at our refineries and facilities will reduce our revenues and cash available for distributions to our unitholders and payments of our debt obligations.

Our refineries and facilities consist of many processing units, a number of which have been in operation for a long time. One or more of the units may require additional unscheduled downtime for unanticipated maintenance or repairs that are more frequent than our scheduled turnaround for each unit every one to five years. Scheduled and unscheduled maintenance reduce our revenues and increase our operating expenses during the period of time that our processing units are not operating and could reduce our ability to make distributions to our unitholders and payments of our debt obligations.

If we do not successfully execute growth through acquisitions, our future growth and ability to increase distributions to our unitholders may be limited.

Our ability to grow depends in substantial part on our ability to make acquisitions that result in an increase in the cash generated from operations per unit. If we are unable to make these accretive acquisitions either because we are: (1) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them, (2) unable to consummate acquisitions on favorable terms, (3) unable to obtain financing for these acquisitions on economically acceptable terms, or (4) outbid by competitors, then our future growth and ability to increase distributions to our unitholders may be limited. Furthermore, any acquisition, involves potential risks, including, among other things:

- performance from the acquired assets and businesses that is below the forecasts we used in evaluating the acquisition;
- a significant increase in our indebtedness and working capital requirements;
- an inability to timely and effectively integrate the operations of recently acquired businesses or assets, particularly those in new geographic areas or in new lines of business;
- the incurrence of substantial seen or unforeseen environmental and other liabilities arising out of the acquired businesses or assets;
- the diversion of management’s attention from other business concerns;
- customer or key employee losses at the acquired businesses; and
- significant changes in our capitalization and results of operations.

Our asset reconfiguration and enhancement initiatives may not result in revenue or cash flow increases, may be subject to significant cost overruns and are subject to regulatory, environmental, political, legal and economic risks, which could adversely affect our business, operating results, cash flows and financial condition.

Historically we have grown our business in part through the reconfiguration and enhancement of our existing refinery assets. For example, we completed an expansion project at our Shreveport refinery to increase throughput capacity and crude oil processing flexibility in May 2008. Additionally, in February 2016 we completed an expansion project that increased production capacity at our Montana refinery by 15,000 bpd to 25,000 bpd. These expansion projects and the construction of other additions or modifications to our existing refineries have and will continue to involve numerous regulatory, environmental, political, legal, labor and economic uncertainties beyond our control, which could cause delays in construction or require the expenditure of significant amounts of capital, which we may finance with additional indebtedness or by issuing additional equity securities. Our forecasted internal rates of return on such projects are also based on our projections of future market fundamentals, which are not within our control, including changes in general economic conditions, available alternative supply and customer demand. For example, the total cost of the Shreveport refinery expansion project completed in 2008 was approximately $375.0 million and was significantly over budget due primarily to increased construction labor costs. Future reconfiguration and enhancement projects may not be completed at the budgeted cost, on schedule, or at all due to the risks described above which could significantly affect our cash flows and financial condition.

We face substantial competition from other refining companies.

The refining industry is highly competitive. Our competitors include large, integrated, major or independent oil companies that, because of their more diverse operations, larger refineries or stronger capitalization, may be better positioned than we are to withstand volatile industry conditions, including shortages or excesses of crude oil or refined products or intense price competition at the wholesale level. If we are unable to compete effectively, we may lose existing customers or fail to acquire new customers. For example, if a competitor attempts to increase market share by reducing prices, our operating results and cash available for distribution to our unitholders and payments of our debt obligations could be reduced.

The amount of cash we have available for distribution to unitholders depends primarily on our cash flow and not solely on profitability.

Unitholders should be aware that the amount of cash we have available for distribution depends primarily upon our cash flow, including cash flow from financial reserves and working capital borrowings, and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record net losses and may not make cash distributions during periods when we record net income.

35

Table of Contents

Distributions to unitholders and payments of our debt obligations could be adversely affected by a decrease in the demand for our specialty products.

Changes in our customers' products or processes may enable our customers to reduce consumption of the specialty products that we produce or make our specialty products unnecessary. Should a customer decide to use a different product due to price, performance or other considerations, we may not be able to supply a product that meets the customer's new requirements. In addition, the demand for our customers' end products could decrease, which could reduce their demand for our specialty products. Our specialty products customers are primarily in the industrial goods, consumer goods and automotive goods industries and we are therefore susceptible to overall economic conditions, which may change demand patterns and products in those industries. Consequently, it is important that we develop and manufacture new products to replace the sales of products that mature and decline in use. If we are unable to manage successfully the maturation of our existing specialty products and the introduction of new specialty products our revenues, net income and cash available for distribution to our unitholders and payments of our debt obligations could be reduced.

Distributions to unitholders and payments of our debt obligations could be adversely affected by a decrease in demand for fuel products in the markets we serve.

Any sustained decrease in demand for fuel products in the markets we serve could result in a significant reduction in our cash flows, reducing our ability to make distributions to unitholders and payments of our debt obligations. Factors that could lead to a decrease in market demand include:

- a recession or other adverse economic condition that results in lower spending by consumers on gasoline, diesel and travel;
- higher fuel taxes or other governmental or regulatory actions that increase, directly or indirectly, the cost of fuel products;
- an increase in fuel economy or the increased use of alternative fuel sources;
- an increase in the market price of crude oil that lead to higher refined product prices, which may reduce demand for fuel products;
- competitor actions; and
- availability of raw materials.

We depend on unionized labor for the operation of our facilities. Any work stoppages or labor disturbances at these facilities could disrupt our business.

Substantially all of our operating personnel at our Shreveport, Superior, Montana, Princeton, Cotton Valley, Karns City, Dickinson and Missouri facilities are employed under collective bargaining agreements. If we are unable to renegotiate these agreements as they expire, any work stoppages or other labor disturbances at these facilities could have an adverse effect on our business and reduce our ability to make distributions to our unitholders. In addition, employees who are not currently represented by labor unions may seek union representation in the future, and any renegotiation of current collective bargaining agreements may result in terms that are less favorable to us.

Because of the volatility of crude oil and refined products prices, our method of valuing our inventory may result in decreases in net income.

The nature of our business requires us to maintain substantial quantities of crude oil and refined product inventories. Because crude oil and refined products are essentially commodities, we have no control over the changing market value of these inventories. Because our inventory is valued at the lower of cost or market ("LCM") value, if the market value of our inventory were to decline to an amount less than our cost, we would record a write-down of inventory and a non-cash charge to cost of sales. In a period of decreasing crude oil or refined product prices, our inventory valuation methodology may result in decreases in net income. For example, due to the significant decrease in crude oil prices in 2015 and 2014, we recorded $81.8 million and $74.1 million, respectively, of LCM adjustments.

The operating results for our fuel products segment, including the asphalt we produce and sell, are seasonal and generally lower in the first and fourth quarters of the year.

The operating results for our fuel products segment, including the selling prices of asphalt products we produce, can be seasonal. Asphalt demand is generally lower in the first and fourth quarters of the year as compared to the second and third quarters due to the seasonality of road construction. Demand for gasoline is generally higher during the summer months than during the winter months due to seasonal increases in highway traffic. In addition, our natural gas costs can be higher during the winter months. Our operating results for the first and fourth calendar quarters may be lower than those for the second and third calendar quarters of each year as a result of this seasonality.

Table of Contents

Due to our lack of asset and geographic diversification, adverse developments in our operating areas would reduce our ability to make distributions to our unitholders.

We rely primarily on sales generated from products processed at the facilities we own. Furthermore, the majority of our assets and operations are located in Louisiana, Wisconsin, Montana and Texas. Due to our lack of diversification in asset type and location, an adverse development in these businesses or areas, including adverse developments due to catastrophic events or weather, decreased supply of crude oil and feedstocks and/or decreased demand for refined petroleum products, would have a significantly greater impact on our financial condition and results of operations than if we maintained more diverse assets in more diverse locations.

Climate change legislation or regulations restricting emissions of GHG could result in increased operating costs and a decreased demand for our refined products.

The EPA has adopted rules requiring the reporting of carbon dioxide, methane and other GHGs from specified large GHG emissions sources in the U.S., including refineries, on an annual basis. Operators of covered sources in the U.S. must annually monitor and report these GHG emissions to EPA and certain state agencies. Our refineries and certain of our other facilities are subject to the federal GHG reporting requirements because of combustion GHG emissions and potential fugitive emissions that exceed reporting thresholds and our compliance with this reporting program has increased our operating costs.

In addition, the EPA has determined that emissions of GHG present a danger to public health and the environment and, based on these findings, has adopted regulations under existing provisions of the CAA that, among other things, establish Title V and PSD permitting requirements for certain large stationary sources of GHG that apply to certain of our facilities, including our refineries, which are potential major sources of GHG emissions. We may be required to install “best available control technology” to limit emissions of GHG from any new or significantly modified facilities that we may seek to construct in the future if they would otherwise emit large volumes of GHG. PSD permits with GHG emissions limitations have generally required efficient combustion requirements on sources that burn large volumes of fossil fuels rather than post-combustion GHG capture requirements. Also, as part of a settlement in December 2010 with certain environmental groups derived out of legal challenges seeking judicial review of an EPA final rule on standards of performance for petroleum refineries, the EPA agreed to propose new source performance standards for GHG emissions from petroleum refineries by December 10, 2011, and to finalize these rules by November 15, 2012. While no such standards have been proposed by the EPA to date, we expect the agency to continue to pursue this rulemaking. Depending on the nature of the requirements imposed by the EPA as part of this rulemaking, we could encounter increased operating costs and capital expenditures that could be significant.

While the U.S. Congress has from time to time considered legislation to reduce emissions of GHG, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of federal climate legislation in the U.S., a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions. If the U.S. Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on our operations and reduce demand for refined products. The ultimate impact of any carbon tax on our operations would further depend upon whether a carbon tax supplanted the other federal GHG regulations to which we are currently subject or is administered as an additional program.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business, financial condition, demand for our products, results of operations and cash flows. For example, on August 18, 2015, the EPA published a proposed rule that is expected to be finalized in 2016 and will establish emission standards for methane and volatile organic compounds released from new and modified oil and natural gas production and natural gas processing and transmissions facilities, as part of President Obama’s Administration’s efforts to reduce methane emissions from the oil and natural gas sector by up to 45 percent from 2012 levels by 2025. Moreover, on an international level, the U.S. is one of almost 200 nations that agreed on December 12, 2015, to an international climate change agreement in Paris, France, that calls for countries to set their own GHG emissions targets and be transparent about the measures each country will use to achieve its GHG emissions targets. It is not possible at this time to predict how or when the U.S. might impose legal requirements as a result of this international agreement. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHG in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climate events that could have an adverse effect on our assets and operations.

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

Our operations involve the purchasing of crude oil including from the Bakken Shale and shipping it by rail on railcars that we lease. Recent derailments of trains transporting crude oil in the U.S. and Canada have caused various regulatory agencies and

Table of Contents

industry organizations, as well as federal, state and municipal governments, to focus attention on transportation of flammable materials by rail. Transportation safety regulators in the U.S. and Canada are concerned that crude oil from the Bakken Shale may be more flammable than crude oil from other producing regions and are investigating that issue. On May 8, 2015, the Pipeline and Hazardous Materials Safety Administration ("PHMSA") adopted a final rule that, among other things, imposes a new tank car design standard, a phase out by as early as January 2018 for older DOT-111 tank cars that are not retrofitted, and a classification and testing program for unrefined petroleum based products, including crude oil. The rule also includes new operational requirements such as speed restrictions. The Canadian government's transportation department has also issued new regulations that align with the U.S. rule in many respects. We are currently reviewing the final rule in detail to assess the expected impact on our business, including the potential impact on the tank cars that we lease to transport our products. We are unable to predict what impact these or other regulatory changes may have, if any, on our business or the industry as a whole. As a result of the final rule, certain of our tank cars that we lease could be deemed unfit for further commercial use or require retrofits or modifications, and the costs associated with any required retrofits or modifications could be substantial. In addition, the new tank car design requirements may result in significant constraints on transportation capacity during the period while tank cars are being retrofitted or newly constructed to comply with the new regulations. Such transportation capacity constraints could increase the cost of transporting crude oil by rail. We cannot assure that costs incurred to comply with any new standards and regulations, including those finalized by PHMSA in May 2015, will not be material to our business, financial condition or results of operations. In addition, any derailment involving crude oil that we have purchased or are shipping may result in claims being brought against us that may involve significant liabilities. Although we believe that we are adequately insured against such events, we cannot provide assurance that our policies will cover the entirety of any damages that may arise from such an event.

We could be subject to damages based on claims brought against us by our customers or lose customers as a result of the failure of our products to meet certain quality specifications.

Our specialty products provide precise performance attributes for our customers' products. If a product fails to perform in a manner consistent with the detailed quality specifications required by the customer, the customer could seek replacement of the product or damages for costs incurred as a result of the product failing to perform as guaranteed. A successful claim or series of claims against us could result in a loss of one or more customers and reduce our ability to make distributions to unitholders and payments of our debt obligations.

The enactment of derivatives legislation could have an adverse effect on our ability to use derivative instruments to hedge risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Act"), enacted on July 21, 2010, established federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The Act requires the Commodity Futures Trading Commission ("CFTC") and the SEC to promulgate rules and regulations implementing the Act. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished.

In its rulemaking under the Act, in November 2013, the CFTC proposed new rules to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, their impact on us is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and the associated rules also require us, in connection with covered derivative activities, to comply with clearing and trade-execution requirements or take steps to qualify for an exemption to such requirements. Although we believe that we qualify for the end-user exceptions to the mandatory clearing and trade execution requirements with respect to those swaps entered to hedge our commercial risks, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. In addition, certain banking regulators and the CFTC have recently adopted final rules establishing minimum margin requirements for uncleared swaps. Although we expect to qualify for the end-user exception from such margin requirements for swaps entered into to hedge our commercial risks, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. If any of our swaps do not qualify for the commercial end-user exception, posting of collateral could impact liquidity and reduce cash available to us for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect cash flow. The Act and any new regulations could significantly increase the cost of derivative instruments, materially alter the terms of derivative instruments, reduce the availability of derivatives to protect against risks we encounter and reduce our ability to monetize or restructure our existing derivatives contracts. An increase in the cost of derivatives contracts would affect our results of operations and cash available for distribution to our unitholders and payments of our debt obligations. If we reduce our use of derivatives as a result of the Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures and make distributions to our unitholders and payments of our debt obligations. Finally, the Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Act and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our business, our financial condition, and our results of operations.

In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, we may become subject to such regulations, the impact of which is not clear at this time.

We depend on key personnel for the success of our business and the loss of those persons could adversely affect our business and our ability to make distributions to our unitholders.

The loss of the services of any member of senior management or key employee could have an adverse effect on our business and reduce our ability to make distributions to our unitholders. We may not be able to locate or employ on acceptable terms qualified replacements for senior management or other key employees if their services were no longer available. In addition to the employment agreements in place with respect to F. William Grube and R. Patrick Murray, II, on September 14, 2015, we entered into an employment agreement with Timothy Go, Chief Executive Officer. We do not maintain any key-man life insurance.

An increase in interest rates will cause our debt service obligations to increase.

Borrowings under our revolving credit facility bear interest at a rate equal to prime plus a basis points margin or LIBOR plus a basis points margin, at our option. As of December 31, 2015, there were outstanding borrowings under our revolving credit facility of $111.0 million and $66.8 million in standby letters of credit were issued under our revolving credit facility. The interest rate is subject to adjustment based on fluctuations in the London Interbank Offered Rate (“LIBOR”) or prime rate, as applicable. An increase in the interest rates associated with our floating-rate debt would increase our debt service costs and affect our results of operations and cash flow available for distribution to our unitholders. In addition, an increase in interest rates could adversely affect our future ability to obtain financing or materially increase the cost of any additional financing.

A change of control could result in us facing substantial repayment obligations under our revolving credit agreement, our senior notes and our Collateral Trust Agreement.

Certain events relating to a change of control of our general partner, our partnership and our operating subsidiaries would constitute an event of default under our revolving credit agreement, the indentures governing our senior notes and our Collateral Trust Agreement. In addition, an event of default under our revolving credit agreement would likely constitute an event of default under our master derivatives contracts and the BP Purchase Agreement. As a result, upon a change of control event, we may be required immediately to repay the outstanding principal, any accrued interest on and any other amounts owed by us under our revolving credit facility and the senior notes and the outstanding payment obligations under our master derivatives contracts and the BP Purchase Agreement. The source of funds for these repayments would be our available cash or cash generated from other sources and there can be no assurance that we would have, or be able to obtain, sufficient funds to repay such indebtedness and other payment obligations in full. In addition, our obligations under our revolving credit facility are secured by a first priority lien on our cash, accounts receivable, inventory and certain related assets and our obligations under our master derivatives contracts and the BP Purchase Agreement are secured by a first priority lien on our 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 forgoing (including proceeds of hedge agreements). If we are unable to repay our indebtedness under the revolving credit facility, the payment obligations under our master derivative contracts or the payment obligations under the BP Purchase Agreement or obtain waivers of such defaults, then the lenders under our revolving credit facility, the derivative counterparties under our master derivative contracts and BP would have the right to foreclose on those assets, which would have a material adverse effect on us. There is no restriction in our partnership agreement on the ability of our general partner to enter into a transaction which would trigger the change of control provisions of our revolving credit facility agreement, the indentures governing our senior notes or our Collateral Trust Agreement.

We are exposed to trade credit risk in the ordinary course of our business activities.

We are exposed to risks of loss in the event of nonperformance by our customers and by counterparties of our derivative instruments. Some of our customers and counterparties may be highly leveraged and subject to their own operating and regulatory risks. Even if our credit review and analysis mechanisms work properly, we may experience financial losses in our dealings with other parties. Any increase in the nonpayment or nonperformance by our customers and/or counterparties could reduce our ability to make distributions to our unitholders and payments of our debt obligations.

Risks Inherent in an Investment in Us

At February 29, 2016, the families of our chairman, executive vice chairman, The Heritage Group and certain of their affiliates own an approximate 21.4% limited partner interest in us and own and control our general partner, which has sole responsibility for conducting our business and managing our operations. Our general partner and its affiliates have conflicts of interest and limited fiduciary duties, which may permit them to favor their own interests to other unitholders' detriment.

At February 29, 2016, the families of our chairman, executive vice chairman, the Heritage Group, and certain of their affiliates own an approximate 21.4% limited partner interest in us. In addition, The Heritage Group and the families of our chairman and executive vice chairman own our general partner. Conflicts of interest may arise between our general partner and its affiliates, on the one hand, and us and our unitholders, on the other hand. As a result of these conflicts, the general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders. These conflicts include, among others, the following situations:

- our general partner is allowed to take into account the interests of parties other than us, such as its affiliates, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to our unitholders;
- our general partner has limited its liability and reduced its fiduciary duties under our partnership agreement and has also restricted the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty. As a result of purchasing common units, unitholders consent to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under Delaware law;
- our general partner determines the amount and timing of asset purchases and sales, borrowings, issuance of additional partnership securities, and reserves, each of which can affect the amount of cash that is distributed to unitholders;
- our general partner determines which costs incurred by it and its affiliates are reimbursable by us;
- our general partner determines the amount and timing of any capital expenditures and whether a capital expenditure is a maintenance capital expenditure, which reduces operating surplus, or a capital expenditure for acquisitions or capital improvements, which does not. This determination can affect the amount of cash that is available for distribution to our unitholders and payments of our debt obligations;
- our general partner has the flexibility to cause us to enter into a broad variety of derivative transactions covering different time periods, the net cash receipts from which will increase operating surplus and adjusted operating surplus, with the result that our general partner may be able to shift the recognition of operating surplus and adjusted operating surplus between periods to increase the distributions it and its affiliates receive on their incentive distribution rights; and
- in some instances, our general partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make incentive distributions.

The Heritage Group and certain of its affiliates may engage in limited competition with us.

Pursuant to the omnibus agreement we entered into in connection with our initial public offering, The Heritage Group and its controlled affiliates have agreed not to engage in, whether by acquisition or otherwise, the business of refining or marketing specialty lubricating oils, solvents and wax products as well as gasoline, diesel and jet fuel products in the continental U.S. for so long as it controls us. This restriction does not apply to certain assets and businesses which are more fully described under Part III, Item 13 "Certain Relationships and Related Transactions and Director Independence — Omnibus Agreement."

Although Mr. Grube is prohibited from competing with us pursuant to the terms of his employment agreement, the owners of our general partner, other than The Heritage Group, are not prohibited from competing with us, except to the extent described above.

Our partnership agreement limits our general partner's fiduciary duties to our unitholders and restricts the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement:

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permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include the exercise of its limited call right, its voting rights with respect to the units it owns, its registration rights and its determination whether or not to consent to any merger or consolidation of our partnership or amendment of our partnership agreement;

Table of Contents

- provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as it acted in good faith, meaning it believed the decision was in the best interests of our partnership;
- generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the conflicts committee of the board of directors of our general partner and not involving a vote of unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or be "fair and reasonable" to us. In determining whether a transaction or resolution is "fair and reasonable," our general partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us; and
- provides that our general partner and its officers and directors will not be liable for monetary damages to us or our limited partners for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the general partner or those other persons acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that such person's conduct was criminal.

By purchasing a common unit, a unitholder agrees to be bound by the provisions in the partnership agreement, including the provisions discussed above.

Unitholders have limited voting rights and are not entitled to elect our general partner or its directors.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders do not elect our general partner or its board of directors, and have no right to elect our general partner or its board of directors on an annual or other continuing basis. The board of directors of our general partner is chosen by the members of our general partner. Furthermore, if the unitholders are dissatisfied with the performance of our general partner, the vote of the holders of at least 66 $^{2}/3$% of all outstanding units voting together as a single class is required to remove the general partner. At February 29, 2016, the owners of our general partner and certain of their affiliates own approximately 21.4% of our common units. As a result of these limitations, the price at which the common units trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Our partnership agreement restricts the voting rights of those unitholders owning 20% or more of our common units.

Unitholders' voting rights are further restricted by the partnership agreement provision providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees, and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot vote on any matter. Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

Our general partner interest or control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, our partnership agreement does not restrict the ability of the members of our general partner from transferring their respective membership interests in our general partner to a third party. The new members of our general partner would then be in a position to replace the board of directors and officers of our general partner with their own choices and thereby control the decisions taken by the board of directors.

We do not have our own officers and employees and rely solely on the officers and employees of our general partner and its affiliates to manage our business and affairs.

We do not have our own officers and employees and rely solely on the officers and employees of our general partner and its affiliates to manage our business and affairs. We can provide no assurance that our general partner will continue to provide us the officers and employees that are necessary for the conduct of our business nor that such provision will be on terms that are acceptable to us. If our general partner fails to provide us with adequate personnel, our operations could be adversely impacted and our cash available for distribution to unitholders and payments of our debt obligations could be reduced.

We may issue additional common units without unitholder approval, which would dilute our current unitholders' existing ownership interests.

We may issue an unlimited number of limited partner interests of any type without the approval of our unitholders. Our partnership agreement does not give our unitholders the right to approve our issuance of equity securities ranking junior to the common units at any time. In addition, our partnership agreement does not prohibit the issuance by our subsidiaries of equity securities, which may effectively rank senior to the common units. The issuance of additional common units or other equity securities of equal or senior rank to the common units will have the following effects:

- our unitholders' proportionate ownership interest in us may decrease;
- the amount of cash available for distribution on each unit may decrease;
- the relative voting strength of each previously outstanding unit may be diminished;
- the market price of the common units may decline; and
- the ratio of taxable income to distributions may increase.

Our general partner's determination of the level of cash reserves may reduce the amount of available cash for distribution to unitholders.

Our partnership agreement requires our general partner to deduct from operating surplus cash reserves that it establishes are necessary to fund our future operating expenditures. In addition, our partnership agreement also permits our general partner to reduce available cash by establishing cash reserves for the proper conduct of our business, to comply with applicable law or agreements to which we are a party, or to provide funds for future distributions to partners. These reserves will affect the amount of cash available for distribution to unitholders.

We have a holding company structure in which our subsidiaries conduct our operations and own our operating assets and our ability to distribute cash to our unitholders and make payments of our debt obligations depends on the performance of our subsidiaries and their ability to distribute funds to us.

We are a holding company, and our subsidiaries conduct all of our operations and own all of our operating assets. We have no significant assets other than the equity interests in our subsidiaries. As a result, our ability to distribute cash to our unitholders and make payments of debt obligations depends on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us is restricted by our revolving credit facility and the indentures governing our senior notes and may be restricted by, among other things, applicable state laws and other laws and regulations. If we are unable to obtain the funds necessary to distribute cash to our unitholders or make payments of debt obligations, we may be required to adopt one or more alternatives, such as a refinancing of our indebtedness or incurring borrowings under our revolving credit facility. We cannot assure unitholders that we would be able to refinance our indebtedness or that the terms on which we could refinance our indebtedness would be favorable.

Cost reimbursements due to our general partner and its affiliates will reduce cash available for distribution to unitholders and payments of our debt obligations.

Prior to making any distribution on the common units, we will reimburse our general partner and its affiliates for all expenses they incur on our behalf. Any such reimbursement will be determined by our general partner and will reduce the cash available for distribution to unitholders and payments of our debt obligations. These expenses will include all costs incurred by our general partner and its affiliates in managing and operating us. Please read Part III, Item 13 "Certain Relationships and Related Transactions and Director Independence."

Our general partner has a limited call right that may require unitholders to sell their units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 80% of the issued and outstanding common units, our general partner will have the right, but not the obligation, which right it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price. As a result, unitholders may be required to sell their common units to our general partner, its affiliates or us at an undesirable time or price and may not receive any return on their investment. Unitholders may also incur a tax liability upon a sale of their common units. At February 29, 2016, our general partner and its affiliates own approximately 21.4% of our common units.

Unitholder liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. Unitholders could be liable for any and all of our obligations as if they were a general partner if:

- a court or government agency determined that we were conducting business in a state but had not complied with that particular state’s partnership statute; or
- unitholders’ right to act with other unitholders to remove or replace the general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute “control” of our business.

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, which we call the Delaware Act, we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Purchasers of units who become limited partners are liable for the obligations of the transferring limited partner to make contributions to the partnership that are known to the purchaser of the units at the time it became a limited partner and for unknown obligations if the liabilities could be determined from the partnership agreement. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

Our common units have a low trading volume compared to other units representing limited partner interests.

Our common units are traded publicly on the NASDAQ Global Select Market under the symbol “CLMT.” However, our common units have a low average daily trading volume compared to many other units representing limited partner interests quoted on the NASDAQ Global Select Market.

The market price of our common units may continue to be volatile and may also be influenced by many factors, some of which are beyond our control, including:

- our quarterly distributions;
- our quarterly or annual earnings or those of other companies in our industry;
- changes in commodity prices or refining margins;
- loss of a large customer;
- announcements by us or our competitors of significant contracts or acquisitions;
- changes in accounting standards, policies, guidance, interpretations or principles;
- general economic conditions;
- the failure of securities analysts to cover our common units or changes in financial estimates by analysts;
- future sales of our common units; and
- the other factors described in Item 1A “Risk Factors” of this Annual Report.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the IRS were to treat us as a corporation for federal income tax purposes, or if we become subject to material additional amounts of entity-level taxation for state tax purposes, then our cash available for distribution to our unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for U.S. federal income tax purposes.

Despite the fact that we are organized as a limited partnership under Delaware law, we would be treated as a corporation for federal income tax purposes unless we satisfy a “qualifying income” requirement. Based upon our current operations and private letter rulings we have received with respect to certain aspects of our business, we believe we satisfy the qualifying income requirement. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the unitholders, likely causing a substantial reduction in the value of our common units.

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to a material amount of entity-level taxation for federal, state or local income tax purposes, the anticipated quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us. At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise, or other forms of taxation. Imposition of a similar tax on us in the jurisdictions in which we operate or in other jurisdictions to which we may expand could substantially reduce our cash available for distribution to our unitholders.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, the Fiscal Year 2017 Budget proposed by the President recommends that certain publicly traded partnerships earning income from activities related to fossil fuels be taxed as corporations beginning in 2022. From time to time, members of Congress propose and consider such substantive changes to the existing U.S. federal income tax laws that affect publicly traded partnerships. If successful, the Obama Administration's proposal or other similar proposals could eliminate the qualifying income exception to the treatment of all publicly-traded partnerships as corporations upon which we rely for our treatment as a partnership for U.S. federal income tax purposes.

In addition, the IRS, on May 5, 2015, issued proposed regulations (the "Proposed Regulations") concerning which activities give rise to qualifying income within the meaning of Section 7704 of the Internal Revenue Code. We have requested and obtained favorable private letter rulings (the "Rulings") from the IRS with respect to certain aspects of our business. We believe that our Rulings are largely consistent with the Proposed Regulations, and we have participated in the comment process in order to confirm that the final regulations are consistent with our Rulings. However, finalized regulations could modify the amount of our gross income that we are able to treat as qualifying income for the purposes of the qualifying income requirement.

Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

Unitholders will be required to pay taxes on their share of our taxable income even if they do not receive any cash distributions from us, including their share of income from the cancellation of debt.

Unitholders will be required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, whether or not they receive cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability which results from that income.

In response to current market conditions, we may engage in transactions to delever the Partnership and manage our liquidity that may result in income and gain to our unitholders without a corresponding cash distribution. For example, if we sell assets and use the proceeds to repay existing debt or fund capital expenditures, you may be allocated taxable income and gain resulting from the sale without receiving a cash distribution. Further, taking advantage of opportunities to reduce our existing debt, such as debt exchanges, debt repurchases or modifications of our existing debt, could result "cancellation of indebtedness income" (also referred to as "COD income") being allocated to our unitholders as taxable income. Unitholders may be allocated COD income, and income tax liabilities arising therefrom may exceed cash distributions. The ultimate effect of any such allocations will depend on the unitholder's individual tax position with respect to its units. Unitholders are encouraged to consult their tax advisors with respect to the consequences to them of COD income.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have terminated as a partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns for one calendar year and could result in a significant deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than the calendar year, the closing of our taxable year may also result in more than 12 months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but it would result in our being treated as a new partnership for federal income tax purposes. If we were treated as a new partnership, we would be required to make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred. The IRS recently announced a relief procedure whereby if a publicly-traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership may be permitted to provide only a single Schedule K-1 to unitholders for the two short tax periods included in the year in which the termination occurs.

Table of Contents

Tax gain or loss on the disposition of our common units could be more or less than expected.
If our unitholders sell their common units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of a unitholder’s allocable share of our net taxable income result in a decrease in such unitholder’s tax basis in their common units, the amount, if any, of such prior excess distributions with respect to the units they sell will, in effect, become taxable income to our unitholders if they sell such units at a price greater than their tax basis in those units, even if the price they receive is less than their original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture of depreciation and deductions and certain other items. In addition, because the amount realized includes a unitholder’s share of our nonrecourse liabilities, if unitholders sell their units, they may incur a tax liability in excess of the amount of cash they receive from the sale.
Tax-exempt entities and non-U.S. persons face unique tax issues from owning common units that may result in adverse tax consequences to them.
Investments in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as “IRAs”), and non-U.S. persons raise issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Allocations and/or distributions to non-U.S. persons will be reduced by withholding taxes imposed at the highest effective tax rate applicable to non-U.S. persons, and each non-U.S. person will be required to file a U.S. federal tax return and pay tax on their share of our taxable income. If you are a tax-exempt entity or a non-U.S. person, you should consult your tax advisor before investing in our common units.
If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution to our unitholders.
Recently enacted legislation alters the procedures for assessing and collecting taxes due for taxable years beginning after December 31, 2017, in a manner that could substantially reduce cash available for distribution to our unitholders.
The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest by the IRS may materially and adversely impact the market for our common units and the price at which they trade. Our costs of any contest by the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution.
Recently enacted legislation applicable to us for taxable years beginning after December 31, 2017, alters the procedures for auditing large partnerships and also alters the procedures for assessing and collecting taxes due (including applicable penalties and interest) as a result of an audit. Unless we are eligible to (and choose to) elect to issue revised Schedules K-1 to our partners with respect to an audited and adjusted return, the IRS may assess and collect taxes (including any applicable penalties and interest) directly from us in the year in which the audit is completed under the new rules. If we are required to pay taxes, penalties and interest as the result of audit adjustments, cash available for distribution to our unitholders may be substantially reduced. In addition, because payment would be due for the taxable year in which the audit is completed, unitholders during that taxable year would bear the expense of the adjustment even if they were not unitholders during the audited taxable year.
We have subsidiaries that are treated as a corporation for federal income tax purposes and subject to corporate-level income taxes.
Even though we (as a partnership for U.S. federal income tax purposes) are not subject to U.S. federal income tax, some of our operations are currently conducted through subsidiaries that are organized as a corporation for U.S. federal income tax purposes. The taxable income, if any, of such subsidiaries are subject to corporate-level U.S. federal income taxes, which may reduce the cash available for distribution to us and, in turn, to our unitholders. If the IRS or other state or local jurisdictions were to successfully assert that these corporations have more tax liability than we anticipate or legislation was enacted that increased the corporate tax rate, the cash available for distribution could be further reduced. The income tax return filings positions taken by these corporate subsidiaries require significant judgment, use of estimates, and the interpretation and application of complex tax laws. Significant judgment is also

required in assessing the timing and amounts of deductible and taxable items. Despite our belief that the income tax return positions taken by these subsidiaries is fully supportable, certain positions may be successfully challenged by the IRS, state or local jurisdictions.

We will treat each purchaser of our common units as having the same tax benefits without regard to the actual common units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units and because of other reasons, we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from unitholders' sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to their tax returns.

We will prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred. Nonetheless, we allocate certain deductions for depreciation of capital additions based upon the date the underlying property is placed in service. The U.S. Department of the Treasury recently adopted final Treasury Regulations allowing a similar monthly simplifying convention for taxable years beginning on or after August 3, 2015. However, such regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to successfully challenge our proration method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss, and deduction among our unitholders.

We have adopted certain valuation methodologies in determining unitholder's allocations of income, gain, loss and deduction. The IRS may challenge these methods or the resulting allocations, and such a challenge could adversely affect the value of our common units.

In determining the items of income, gain, loss and deduction allocable to our unitholders, we must routinely determine the fair market value of our respective assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we make many fair market value estimates using a methodology based on the market value of our common units as a means to measure the fair market value of our respective assets. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction.

A successful IRS challenge to these methods or allocations could adversely affect the amount, character, and timing of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

A unitholder whose common units are the subject of a securities loan (e.g., a loan to a "short seller" to cover a short sale of common units) may be considered as having disposed of those common units. If so, he would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because there are no specific rules governing the U.S. federal income tax consequences of loaning a partnership interest, a unitholder whose common units are the subject of a securities loan may be considered as having disposed of the loaned units. In that case, the unitholder may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller should modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

Unitholders will likely be subject to state and local taxes and return filing requirements in states where they do not live as a result of investing in our common units.

In addition to U.S. federal income taxes, our unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if they do not live in any of those jurisdictions. We own assets and conduct business in 47 states. Our unitholders may be required to file foreign, state and local income tax returns and pay state and local income taxes in any state in which we now or may conduct business in the future. Further, they may be subject to penalties for failure to comply with those requirements. As we make acquisitions or expand our business, we may own assets or conduct business in additional states or foreign jurisdictions that impose a personal income tax. It is the responsibility of our unitholders to file all U.S. federal, foreign, state and local tax returns.

Item 1B. Unresolved Staff Comments

None.

Table of Contents

Item 3. 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 incident 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. Please see Items 1 and 2 “Business and Properties — Environmental and Occupational Health and Safety Matters” for a description of our current regulatory matters related to the environment, health and safety. Additionally, the information provided under Note 6 “Commitments and Contingencies” in Part II, Item 8 “Financial Statements and Supplementary Data — Notes to Consolidated Financial Statements” is incorporated herein by reference.

Item 4. Mine Safety Disclosures

Not applicable.

Table of Contents

PART II

Item 5. Market for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities
Market Information
Our common units are quoted and traded on the NASDAQ Global Select Market ("NASDAQ") under the symbol "CLMT." The following table shows the low and high sales prices per common unit, as reported by NASDAQ, for the periods indicated. Cash distributions presented below represent amounts declared subsequent to each respective quarter end based on the results of that quarter.

	Low	High	Cash Distribution per Unit (1)
2014:			
First quarter	$24.23	$30.60	$0.685
Second quarter	$25.74	$32.81	$0.685
Third quarter	$26.60	$33.30	$0.685
Fourth quarter	$18.66	$29.70	$0.685
2015:			
First quarter	$20.65	$29.14	$0.685
Second quarter	$24.03	$28.49	$0.685
Third quarter	$18.26	$28.33	$0.685
Fourth quarter	$17.70	$27.88	$0.685

(1) We also paid cash distributions to our general partner with respect to its 2% general partner interest and, to the extent distributions exceeded $0.495 per unit, its incentive distribution rights, as described below in "Cash Distribution Policy — General Partner Interest and Incentive Distribution Rights."

As of February 29, 2016, there were approximately 42 unitholders of record of our common units. The actual number of unitholders is greater than the number of holders of record. As of February 29, 2016, there were 75,884,400 common units outstanding. The last reported sale price of our common units by NASDAQ on February 26, 2016, was $9.55.

Cash Distribution Policy

General. Within 45 days after the end of each quarter, we distribute our available cash (as defined in our partnership agreement) to unitholders of record on the applicable record date.

Available Cash. Available cash generally means, for any quarter, all cash on hand at the end of the quarter:

- less the amount of cash reserves established by our general partner to:
- provide for the proper conduct of our business;
- comply with applicable law, any of our debt instruments or other agreements; and
- provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters.
- plus all cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter for which the determination is being made. Working capital borrowings are generally borrowings that will be made under our revolving credit facility and in all cases are used solely for working capital purposes or to pay distributions to partners.

Cash Distribution Policy. We distribute to the holders of common units on a quarterly basis at least the minimum quarterly distribution of $0.45 per unit, or $1.80 in aggregate per year, to the extent we have sufficient cash from our operations after establishment of cash reserves and payment of fees and expenses, including payments to our general partner. However, there is no guarantee that we will pay the minimum quarterly distribution on the units in any quarter. Even if our cash distribution policy is not modified or revoked, the amount of distributions paid under our policy and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our partnership agreement. We will be prohibited from making any distributions to unitholders if it would cause an event of default, or an event of default exists, under our debt instruments, including our revolving credit agreement and the indentures governing our 2021 Notes, 2022 Notes and 2023 Notes. Please read Part II,

Table of Contents

Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Debt and Credit Facilities" for a discussion of the restrictions in our debt instruments that restrict our ability to make distributions. On February 12, 2016, we paid a quarterly cash distribution of $0.685 per unit on all outstanding units totaling approximately $57.4 million for the quarter ended December 31, 2015, to all unitholders of record as of the close of business on February 2, 2016.

General Partner Interest and Incentive Distribution Rights. Our general partner is entitled to 2% of all quarterly distributions since inception that we make prior to our liquidation. This general partner interest is represented by 1,548,660 general partner units. Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest. The general partner's 2% interest in these distributions may be reduced if we issue additional units in the future and our general partner does not contribute a proportionate amount of capital to us to maintain its 2% general partner interest. Our general partner also currently holds incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 50%, of the cash we distribute from operating surplus (as defined in our partnership agreement) in excess of $0.495 per unit. The maximum distribution of 50% includes distributions paid to our general partner on its 2% general partner interest, and assumes that our general partner maintains its general partner interest at 2%. The maximum distribution of 50% does not include any distributions that our general partner may receive on units that it owns. Our general partner earned incentive distribution rights of approximately $16.8 million and $15.4 million during the years ended December 31, 2015 and 2014, respectively.

Our general partner is entitled to incentive distributions if the amount we distribute to unitholders with respect to any quarter exceeds specified target levels shown below:

	Total Quarterly Distribution Target Amount Per Common Unit	Marginal Percentage Interest in Distributions: Unitholders	Marginal Percentage Interest in Distributions: General Partner
Minimum Quarterly Distribution	$0.45	98 %	2 %
First Target Distribution	up to $0.495	98 %	2 %
Second Target Distribution	above $0.495 up to $0.563	85 %	15 %
Third Target Distribution	above $0.563 up to $0.675	75 %	25 %
Thereafter	above $0.675	50 %	50 %

Equity Compensation Plans

The equity compensation plan information required by Item 201(d) of Regulation S-K in response to this Item 5 is incorporated by reference into Part III, Item 12 "Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters" of this Annual Report.

Sales of Unregistered Securities

None.

Issuer Purchases of Equity Securities

None.

Item 6. Selected Financial Data

The following table shows selected historical consolidated financial and operating data of the Company. The selected historical consolidated financial data as of and after December 31, 2015, 2014, 2013, 2012 and 2011 includes the operations acquired as part of the acquisitions of Superior, Missouri, Calumet Packaging, Royal Purple, Montana, San Antonio, Bel-Ray, United Petroleum, Anchor Drilling Fluids and Anchor Oilfield Services from their respective dates of acquisition, September 30, 2011, January 3, 2012, January 6, 2012, July 3, 2012, October 1, 2012, January 2, 2013, December 10, 2013, February 28, 2014, March 31, 2014, and August 1, 2014.

The following table includes the non-GAAP financial measures EBITDA, Adjusted EBITDA and Distributable Cash Flow. For a reconciliation of EBITDA, Adjusted EBITDA and Distributable Cash Flow to net income (loss) and net cash provided by operating activities, our most directly comparable financial performance and liquidity measures calculated in accordance with U.S. generally accepted accounting principles ("GAAP"), please read "—

Non-GAAP Financial Measures."

We derived the information in the following table from, and the information should be read together with, and is qualified in its entirety by reference to, the historical consolidated financial statements and the accompanying notes included in Item 8 "Financial Statements and Supplementary Data" except for operating data, such as sales volume, feedstock runs and facility production. The following table also should be read together with Part II, Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

	Year Ended December 31,				
	2015	2014	2013	2012	2011
	(In millions)				
Summary of Operations Data:					
Sales	$4,212.8	$5,791.1	$5,421.4	$4,657.3	$3,134.9
Cost of sales	3,618.2	5,261.4	5,011.4	4,144.1	2,860.8
Gross profit	594.6	529.7	410.0	513.2	274.1
Operating costs and expenses:					
Selling	146.0	149.6	62.6	41.6	12.2
General and administrative	135.5	98.3	82.1	60.9	38.6
Transportation	175.5	171.4	142.7	107.9	94.2
Taxes other than income taxes	17.7	13.4	14.2	9.1	5.7
Asset impairment	33.8	36.0	10.5	1.6	—
Insurance recoveries	—	—	—	—	(8.7)
Other	11.1	14.2	6.3	6.2	6.8
Operating income	75.0	46.8	91.6	285.9	125.3
Other income (expense):					
Interest expense	(104.9)	(110.8)	(96.8)	(85.6)	(48.7)
Debt extinguishment costs	(46.6)	(89.9)	(14.6)	—	(15.1)
Realized gain (loss) on derivative instruments	8.1	43.8	(4.7)	9.5	(7.9)
Unrealized gain (loss) on derivative instruments	(39.5)	(0.6)	25.7	(3.8)	(10.4)
Loss from unconsolidated affiliates	(61.5)	(3.4)	(0.3)	—	—
Other	1.6	1.1	3.0	0.5	0.8
Total other expense	(242.8)	(159.8)	(87.7)	(79.4)	(81.3)
Net income (loss) before income taxes	(167.8)	(113.0)	3.9	206.5	44.0
Income tax expense (benefit)	(28.4)	(0.8)	0.4	0.8	1.0
Net income (loss)	$(139.4)	$(112.2)	$3.5	$205.7	$43.0

Table of Contents

	Year Ended December 31,				
	2015	2014	2013	2012	2011
	(In millions, except unit, per unit and operating data)				
Weighted average limited partner units outstanding:					
Basic	74,896,096	69,671,827	67,938,784	55,559,183	42,598,876
Diluted	74,896,096	69,671,827	67,938,784	55,676,741	42,644,086
Limited partners' interest basic net income (loss) per unit	$(2.05)	$(1.80)	$(0.17)	$3.51	$0.98
Limited partners' interest diluted net income (loss) per unit	$(2.05)	$(1.80)	$(0.17)	$3.50	$0.98
Cash distributions declared per limited partner unit	$2.74	$2.74	$2.70	$2.30	$1.94
Balance Sheet Data (at period end):					
Property, plant and equipment, net	$1,719.2	$1,464.4	$1,160.4	$986.9	$842.1
Total assets	$2,944.7	$3,085.1	$2,658.4	$2,223.6	$1,705.7
Accounts payable	$316.6	$419.9	$355.8	$332.6	$302.8
Long-term debt	$1,773.4	$1,678.8	$1,081.1	$834.1	$560.7
Total partners' capital	$603.9	$810.2	$1,062.8	$889.8	$728.9
Cash Flow Data:					
Net cash flow provided by (used in):					
Operating activities	$376.4	$226.8	$39.1	$380.1	$63.8
Investing activities	$(389.0)	$(658.8)	$(370.3)	$(624.2)	$(460.4)
Financing activities	$9.7	$319.4	$420.1	$276.2	$396.7
Other Financial Data:					
EBITDA	$129.1	$226.3	$233.1	$383.7	$170.9
Adjusted EBITDA	$257.7	$305.9	$241.5	$404.6	$211.0
Distributable Cash Flow	$161.9	$146.3	$18.8	$281.1	$127.2
Operating Data (bpd): (1)					
Total sales volume (2)	126,216	122,852	116,477	97,789	66,134
Total feedstock runs (3)	123,051	117,427	110,237	97,600	69,295
Total facility production (4)	122,795	114,146	106,592	96,172	70,909

(1) Operating data excludes operations of the oilfield services segment.

(2) Total sales volume includes sales from the production at our facilities and certain third-party facilities pursuant to supply and/or processing agreements, sales of inventories and the resale of crude oil to third party customers. Total sales volume includes the sale of purchased fuel product blendstocks, such as ethanol and biodiesel, as components of finished fuel products in our fuel products segment sales.

(3) 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.

(4) 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. The difference between total facility production and total feedstock runs is primarily a result of the time lag between the input of feedstocks and the production of finished products and volume loss.

Table of Contents

Non-GAAP Financial Measures

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

EBITDA, Adjusted EBITDA and Distributable Cash Flow are used as supplemental financial measures by our management and by external users of our financial statements such as investors, commercial banks, research analysts and others, to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness;
- our operating performance and return on capital as compared to those of other companies in our industry, without regard to financing or capital structure; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

We believe that these non-GAAP measures are useful to analysts and investors as they exclude transactions not related to our core cash operating activities and provide metrics to analyze our ability to pay distributions. We believe that excluding these transactions allows investors to meaningfully analyze trends and performance of our core cash operations.

We define EBITDA for any period as net income (loss) plus interest expense (including debt issuance and extinguishment costs), income taxes and depreciation and amortization.

We define Adjusted EBITDA for any period as: (1) net income (loss) plus (2)(a) interest expense; (b) income taxes; (c) depreciation and amortization; (d) impairment; (e) unrealized losses from mark to market accounting for hedging activities; (f) realized gains under derivative instruments excluded from the determination of net income (loss); (g) non-cash equity based compensation expense and other non-cash items (excluding items such as accruals of cash expenses in a future period or amortization of a prepaid cash expense) that were deducted in computing net income (loss); (h) debt refinancing fees, premiums and penalties and (i) all extraordinary, unusual or non-recurring items of gain or loss, or revenue or expense; minus (3)(a) unrealized gains from mark to market accounting for hedging activities; (b) realized losses under derivative instruments excluded from the determination of net income and (c) other non-recurring expenses and unrealized items that reduced net income (loss) for a prior period, but represent a cash item in the current period.

We define Distributable Cash Flow for any period as Adjusted EBITDA less replacement and environmental capital expenditures, turnaround costs, cash interest expense (consolidated interest expense less non-cash interest expense), income (loss) from unconsolidated affiliates, net of cash distributions and income tax expense (benefit). Distributable Cash Flow is used by us and our investors and analysts to analyze our ability to pay distributions.

The definitions of Adjusted EBITDA and Distributable Cash Flow that are presented in this Annual Report reflect the calculation of “Consolidated Cash Flow” contained in the indentures governing our 2021 Notes, 2022 Notes and 2023 Notes (as defined in this Annual Report). We are required to report Consolidated Cash Flow to the holders of our 2021 Notes, 2022 Notes and 2023 Notes and Adjusted EBITDA to the lenders under our revolving credit facility, and these measures are used by them to determine our compliance with certain covenants governing those debt instruments. Adjusted EBITDA and Distributable Cash Flow that are presented in this Annual Report for prior periods have been updated to reflect the use of the new calculations. Please read Part II, Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Debt and Credit Facilities” for additional details regarding the covenants governing our debt instruments.

EBITDA, Adjusted EBITDA and Distributable Cash Flow should not be considered alternatives to net income (loss), operating income, net cash provided by operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. In evaluating our performance as measured by EBITDA, Adjusted EBITDA and Distributable Cash Flow, management recognizes and considers the limitations of these measurements. EBITDA and Adjusted EBITDA do not reflect our obligations for the payment of income taxes, interest expense or other

obligations such as capital expenditures. Accordingly, EBITDA, Adjusted EBITDA and Distributable Cash Flow are only three of the measurements that management utilizes. Moreover, our EBITDA, Adjusted EBITDA and Distributable Cash Flow may not be comparable to similarly titled measures of another company because all companies may not calculate EBITDA, Adjusted EBITDA and Distributable Cash Flow in the same manner.
The following tables present a reconciliation of both net income (loss) to EBITDA, Adjusted EBITDA and Distributable Cash Flow, and Distributable Cash Flow, Adjusted EBITDA and EBITDA to net cash provided by operating activities, our most directly comparable GAAP financial performance and liquidity measures, for each of the periods indicated.

Table of Contents

	Year Ended December 31,				
	2015	2014	2013	2012	2011
	(In millions)				
Reconciliation of Net income (loss) to EBITDA, Adjusted EBITDA and Distributable Cash Flow:					
Net income (loss)	$(139.4)	$(112.2)	$3.5	$205.7	$43.0
Add:					
Interest expense	104.9	110.8	96.8	85.6	48.7
Debt extinguishment costs	46.6	89.9	14.6	—	15.1
Depreciation and amortization	145.4	138.6	117.8	91.6	63.1
Income tax expense (benefit)	(28.4)	(0.8)	0.4	0.8	1.0
EBITDA	$129.1	$226.3	$233.1	$383.7	$170.9
Add:					
Unrealized (gain) loss on derivatives	$39.5	$0.6	$(25.7)	$3.8	$10.4
Realized gain (loss) on derivatives, not included in net income (loss) or settled in a prior period	(10.0)	6.6	(1.8)	(5.0)	10.9
Amortization of turnaround costs	29.0	24.5	15.9	13.4	11.4
Impairment charges (1)	58.1	36.0	10.5	1.6	—
Non-cash equity based compensation and other items	12.0	11.9	9.5	7.1	7.4
Adjusted EBITDA	$257.7	$305.9	$241.5	$404.6	$211.0
Less:					
Replacement and environmental capital expenditures (2)	44.2	31.8	64.2	28.3	23.7
Cash interest expense (3)	98.2	104.4	89.8	79.5	45.0
Turnaround costs	19.3	27.6	68.6	14.9	14.1
Loss from unconsolidated affiliates	(37.5)	(3.4)	(0.3)	—	—
Income tax expense (benefit)	(28.4)	(0.8)	0.4	0.8	1.0
Distributable Cash Flow	$161.9	$146.3	$18.8	$281.1	$127.2

(1) Impairment charges for 2015 include a $33.8 million goodwill impairment charge related to the oilfield services segment and $24.3 million impairment charge related to our investment in Juniper.

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

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

	Year Ended December 31,				
	2015	2014	2013	2012	2011
	(In millions)				
Reconciliation of Distributable Cash Flow, Adjusted EBITDA and EBITDA to Net cash provided by operating activities:					
Distributable Cash Flow	$161.9	$146.3	$18.8	$281.1	$127.2
Add:					
Replacement and environmental capital expenditures [(1)]	44.2	31.8	64.2	28.3	23.7
Cash interest expense [(2)]	98.2	104.4	89.8	79.5	45.0
Turnaround costs	19.3	27.6	68.6	14.9	14.1
Loss from unconsolidated affiliates	(37.5)	(3.4)	(0.3)	—	—
Income tax expense (benefit)	(28.4)	(0.8)	0.4	0.8	1.0
Adjusted EBITDA	$257.7	$305.9	$241.5	$404.6	$211.0
Less:					
Unrealized (gain) loss on derivatives	$39.5	$0.6	$(25.7)	$3.8	$10.4
Realized gain (loss) on derivatives, not included in net income (loss) or settled in a prior period	(10.0)	6.6	(1.8)	(5.0)	10.9
Amortization of turnaround costs	29.0	24.5	15.9	13.4	11.4
Impairment charges [(3)]	58.1	36.0	10.5	1.6	—
Non-cash equity based compensation and other items	12.0	11.9	9.5	7.1	7.4
EBITDA	$129.1	$226.3	$233.1	$383.7	$170.9
Add:					
Unrealized (gain) loss on derivatives	39.5	0.6	(25.7)	3.8	10.4
Cash interest expense [(2)]	(98.2)	(104.4)	(89.8)	(79.5)	(45.0)
Asset impairment	33.8	36.0	10.5	1.6	—
Lower of cost or market inventory adjustment	81.8	74.1	(2.1)	6.1	1.9
Non-cash equity based compensation	9.8	6.5	4.8	6.5	4.9
Deferred income tax benefit	(28.5)	(1.2)	—	—	—
Loss from unconsolidated affiliates	61.5	3.4	0.3	—	—
Amortization of turnaround costs	29.0	24.5	15.9	13.4	11.4
Income tax (expense) benefit	28.4	0.8	(0.4)	(0.8)	(1.0)
Provision for doubtful accounts	1.1	0.5	0.1	—	0.4
Debt extinguishment costs	(37.5)	(70.9)	(11.2)	—	(0.7)
Changes in assets and liabilities:					
Accounts receivable	138.0	(0.4)	(32.3)	34.6	(54.5)
Inventories	47.3	43.9	16.4	11.8	(168.9)
Other current assets	3.4	3.9	6.8	15.8	(0.4)
Turnaround costs	(19.3)	(27.6)	(68.6)	(14.9)	(14.1)
Derivative activity	(7.0)	6.7	(1.8)	(5.0)	11.7
Other noncurrent assets	—	—	(0.1)	(4.0)	(0.4)
Accounts payable	(119.9)	(13.1)	6.8	11.1	131.3
Accrued interest payable	(6.5)	15.1	(1.0)	13.0	7.4
Accrued income taxes payable	—	—	(27.6)	(16.1)	0.4
Other liabilities	84.2	(2.1)	2.7	4.6	(2.5)
	6.4	4.2	2.3	(5.6)	0.6

Other, including changes in non-current liabilities					
Net cash provided by operating activities	$376.4	$226.8	$39.1	$380.1	$63.8

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

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

(3) Impairment charges for 2015 include a $33.8 million goodwill impairment charge related to the oilfield services segment and $24.3 million impairment charge related to our investment in Juniper.

Table of Contents

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The historical consolidated financial statements included in this Annual Report reflect all of the assets, liabilities and results of operations of the Company. The following discussion analyzes the financial condition and results of operations of the Company for the years ended December 31, 2015, 2014 and 2013. For the year ended December 31, 2014, the Company realigned its reportable segments for financial reporting purposes as a result of the Anchor and SOS Acquisitions in 2014 resulting in a new segment, oilfield services. This reporting change did not impact segment reporting for 2013 or the Company's consolidated results for any year. Unitholders should read the following discussion and analysis of the financial condition and results of operations of the Company in conjunction with the historical consolidated financial statements and notes of the Company included elsewhere in this Annual Report.

Overview

We are a leading independent producer of high-quality, specialty hydrocarbon products in North America. We are headquartered in Indianapolis, Indiana, and own specialty and fuel products facilities primarily located in northwest Louisiana, northwest Wisconsin, northern Montana, western Pennsylvania, Texas, New Jersey, eastern Missouri and North Dakota. We own and lease oilfield services locations in Texas, Oklahoma, Louisiana, Arkansas, Colorado, Utah, Wyoming, Montana, New Mexico, New York, North Dakota, Pennsylvania and Ohio. We own and lease additional facilities, primarily related to production and distribution of specialty, fuel and oilfield services products, throughout the United States ("U.S."). Our business is organized into three segments: specialty products, fuel products and oilfield services. In our specialty products segment, we process crude oil and other feedstocks into a wide variety of customized lubricating oils, white mineral oils, solvents, petrolatums and waxes. Our specialty products are sold to domestic and international customers who purchase them primarily as raw material components for basic industrial, consumer and automotive goods. We also blend and market specialty products through our Royal Purple, Bel-Ray, TruFuel and Quantum brands. In our fuel products segment, we process crude oil into a variety of fuel and fuel-related products, including gasoline, diesel, jet fuel, asphalt and heavy fuel oils, and from time to time resell purchased crude oil to third party customers. Our oilfield services segment manufactures and markets products and provides oilfield services including drilling fluids, completion fluids and solids control services to the oil and gas exploration industry throughout the U.S.

2015 Update

Financial Results

We reported a net loss of $139.4 million in 2015, versus a net loss of $112.2 million in 2014. We reported Adjusted EBITDA (as defined in Item 6 "Selected Financial Data — Non-GAAP Financial Measures") of $257.7 million in 2015, versus $305.9 million in 2014. We generated $376.4 million of cash flow from operations in 2015, versus $226.8 million in 2014. Distributable Cash Flow ("DCF") (as defined in Item 6 "Selected Financial Data — Non-GAAP Financial Measures") was $161.9 million in 2015, compared to $146.3 million in 2014. Our 2015 full-year Adjusted EBITDA results included a lower of cost or market ("LCM") inventory adjustment of $81.8 million; $24.3 million of losses related to liquidation of last-in, first-out ("LIFO") inventory layers; and $22.3 million of early settlements of select derivative instruments.

Our full year performance benefited from balanced contributions in our specialty products and fuel products segments, both of which benefited from a marked, progressive decline in crude oil prices during the past year. Strength within the specialty and fuel products segments was partially offset by weaker performances in our oilfield services segment and at Dakota Prairie Refining, LLC ("Dakota Prairie"), our joint venture with MDU Resources Group, Inc. ("MDU"). Total refinery throughputs increased to a record 123,051 bpd in 2015, versus 117,427 bpd in 2014, while total sales volumes increased to a record 126,216 bpd in 2015, versus 122,852 bpd in 2014.

Our specialty products segment generated Adjusted EBITDA of $201.7 million in 2015, a decrease of 8.7% versus the prior year period. Gross profit per barrel for our specialty products segment was $40.24 in 2015, versus $41.07 in the prior year.

During 2015, the decrease in the average selling price per barrel of specialty products lagged a significant decline in the average cost of crude oil, our primary input cost, resulting in margin expansion within the specialty products segment. The average price of New York Mercantile Exchange ("NYMEX") West Texas Intermediate ("WTI") crude oil

averaged approximately $49 per barrel in 2015 compared to $93 per barrel in 2014, with average selling prices per barrel of our specialty products declining to a lesser degree. Total specialty products segment sales volumes increased to 25,205 bpd in 2015, an increase of 1.2% when compared to 2014. Demand for lubricating oils, white oils and packaged and synthetic products all grew on a year over year basis, with the packaged and synthetic group generating record total sales of $316.6 million in 2015, an increase of 1.0% from the prior year.
Our fuel products segment generated Adjusted EBITDA of $81.9 million in 2015, an increase of 63.8% versus the prior year period. Gross profit per barrel for our fuel products segment was $4.51 in 2015, versus $0.96 in the prior year. In 2015, production within our fuel products segment reached a record high, as did our total annual fuel product sales volumes.

During 2015, a narrowing in crude oil price differentials served to partially offset strength in fuel products margins. On a volumetric basis, we currently purchase more Western Canadian Select (“WCS”) than any other grade of crude oil. Between 2014 and 2015, the WCS discount versus WTI narrowed from $19 per barrel to $12 per barrel, which served to erode some of the cost advantage realized by our northern fuels refineries in Wisconsin and Montana. We continue to believe a structurally wide WCS-WTI differential remains a significant advantage to the overall profitability of our fuel products segment. In 2016, we intend to increase the volumes of WCS-linked crude oil we process at our fuel products refineries to further capitalize on this advantage.

For benchmarking purposes, we compare our per barrel refined fuel products margin to the U.S. Gulf Coast 2/1/1 crack spread (“Gulf Coast crack spread”). The Gulf Coast crack spread represents the approximate gross margin per barrel that results from processing two barrels of crude oil into one barrel of gasoline and one barrel of ultra-low sulfur diesel fuel. The Gulf Coast crack spread is calculated using the near-month futures price of NYMEX WTI crude oil, the price of U.S. Gulf Coast Pipeline 87 Octane Conventional Gasoline and the price of U.S. Gulf Coast Pipeline Ultra-Low Sulfur Diesel (“ULSD”).

During 2015, the Gulf Coast crack spread averaged approximately $18 per barrel, versus approximately $17 per barrel in 2014. The market ULSD crack spread averaged approximately $17 per barrel during 2015, compared to approximately $21 per barrel in the prior year. The market gasoline crack spread averaged approximately $19 per barrel during 2015, compared to approximately $13 in the prior year.

Although the 2015 average Gulf Coast crack spread was above 2014 levels, the average Gulf Coast crack spread and the average ULSD crack spread significantly decreased in the fourth quarter of 2015. During the fourth quarter of 2015, the Gulf Coast crack spread averaged approximately $11 per barrel, versus approximately $12 per barrel in the 2014 period. The market ULSD crack spread averaged approximately $12 per barrel during the fourth quarter of 2015, compared to approximately $19 per barrel in the prior year period. The market gasoline crack spread averaged approximately $10 per barrel during the fourth quarter of 2015, compared to approximately $4 per barrel in the prior year period. During 2016, the average Gulf Coast crack spread has continued to decline to less than $10 per barrel, further impacting our fuel products refining margins.

We refer to our fuel products segment gross profit per barrel divided by the Gulf Coast crack spread as the “capture rate.” The capture rate is a means of measuring refinery system gross profit per barrel against the benchmark crack spread. During 2015, our capture rate was approximately 25%, versus approximately 6% in 2014.

Included within our fuel products segment gross profit per barrel calculation are the realized cost of crude oil and other feedstocks and other production-related expenses, the most significant portion of which includes labor, plant fuel, utilities, contract services, maintenance, depreciation and process materials. Our gross profit per barrel calculation may not be comparable to similar calculations published by our competitors.

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

Our oilfield services segment generated Adjusted EBITDA of $(25.9) million in 2015, a decrease of 173.8% versus the prior year period. The continued decline in crude oil prices that occurred during 2015 led to a significant reduction in crude oil exploration and production activity, contributing to a nearly 50% year over year decline in the domestic land-based rig count. The subsequent decline in drilling and completion activity had an adverse impact on our oilfield services segment throughout the year. In response to these market conditions, we took steps to significantly reduce costs in the oilfield services segment during 2015, including targeted workforce reductions to help right-size the

segment relative to the needs of our customers. While the oilfield services segment remains challenged in a lower commodity price environment, we continue to manage expenses within the segment.
For a reconciliation of EBITDA, Adjusted EBITDA and Distributable Cash Flow to net income (loss) and net cash provided by operating activities, our most directly comparable financial performance and liquidity measures calculated and presented in accordance with GAAP, please read Item 6 "Selected Financial Data — Non-GAAP Financial Measures."
Quarterly Cash Distribution
We aim to provide our unitholders a stable-to-growing quarterly cash distribution, consistent with our expectations for long-term growth in Adjusted EBITDA and DCF.
On January 19, 2016, we declared a regular quarterly cash distribution of $0.685 per unit, or $2.74 per unit on an annualized basis, for the quarter ended December 31, 2015, on all of our outstanding limited partner units. This distribution level is consistent

with the amount paid to unitholders in the previous quarter. The distribution was paid on February 12, 2016, to unitholders of record as of the close of business on February 2, 2016. For the full year 2015, we paid total cash distributions of $224.6 million, versus $210.2 million in 2014.

However, in light of the current volatility in market conditions and based on a desire to maintain the appropriate level of liquidity, we continue to evaluate whether it is appropriate to maintain our current distribution level. Our board of directors will review the distribution rate quarterly, and there can be no assurance that the current distribution level will be maintained. The actual distributions we will declare will be subject to our operating performance, prevailing market conditions (including crack spreads), the impact of unforeseen events and the approval of our board of directors and the actual distributions will be pursuant to our distribution policy described in Item 5 “Market for Registrant’s Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities — Cash Distribution Policy.”

2016 Capital Spending Forecast

We currently anticipate total capital expenditures to range between $125.0 million and $150.0 million in 2016. This decrease in anticipated capital expenditures is due mainly to the conclusion of a multi-year organic growth project campaign in late 2015.

Liquidity Update

On December 31, 2015, we had availability under our revolving credit facility of approximately $233.5 million, based on a $411.3 million borrowing base, $66.8 million in outstanding standby letters of credit and $111.0 million in outstanding borrowings. In addition, we had $5.6 million of cash on hand as of December 31, 2015. We believe we will continue to have sufficient liquidity from cash on hand, cash flow from operations, borrowing capacity and other means by which to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures. On a continuous basis, we focus on various initiatives, including working capital initiatives, to further enhance our liquidity over time, given current market conditions.

Renewable Fuel Standard Update

We, along with the broader refining industry, remain subject to compliance costs under the Renewable Fuel Standard (“RFS”). Under the regulation of the Environmental Protection Agency (“EPA”), the RFS provides annual requirements for the total volume of renewable transportation fuels which are mandated to be blended into finished petroleum fuels. If a refiner does not meet its required annual Renewable Volume Obligation (“RVO”), the refiner can purchase blending credits in the open market, referred to as Renewable Identification Numbers (“RINs”).

For the year ended December 31, 2015, our total cost to purchase RINs was $38.8 million, versus $9.4 million in 2014. Our gross RINs obligation, which includes RINs that are required to be secured through either blending or through the purchase of RINs in the open market, was 99 million RINs in 2015. For the full-year 2016, we anticipate our gross RINs obligation will increase to 120 million RINs, given recent production capacity expansions at two of our fuel products refineries.

We continue to anticipate that expenses related to RFS compliance have the potential to remain a significant expense for our fuel products segment, assuming current market prices for RINs. Estimated RINs obligations remain subject to fluctuations in fuels production volumes during the full-year 2016.

Organic Growth Projects Update

In early 2016, we concluded a series of organic growth projects requiring a total capital investment of more than $600 million during the past three years. We anticipate these projects will provide significant incremental Adjusted EBITDA over time. During the past twelve months, four major organic projects have commenced operations, including the 20,000 bpd Dakota Prairie refinery in North Dakota; a capacity expansion of our Great Falls, Montana, refinery that increased production capacity from 10,000 bpd to 25,000 bpd; a capacity expansion at our Louisiana, Missouri, esters plant that effectively doubles esters production at that facility and a project at our San Antonio, Texas, refinery that converted a portion of our diesel fuel production into higher-margin solvents.

CEO Succession

On September 14, 2015, our general partner’s Board of Directors named energy industry veteran Timothy Go as incoming chief executive officer (“CEO”), effective January 1, 2016. Mr. Go, 49, joins us with more than 25 years of

experience serving in executive-level roles at leading companies operating in the petroleum refining and specialty products markets. As CEO, Mr. Go will lead and execute our long-term strategy to become the premier global producer and distributor of specialty petroleum products.
Mr. Go joins us from Flint Hills Resources, L.P. (“Flint Hills Resources”), a wholly owned subsidiary of Koch Industries, Inc., where he most recently served as vice president - operations. Previously, Mr. Go spent nearly 20 years in various senior level operations and management roles at ExxonMobil Corporation. As a trained chemical engineer, Mr. Go brings a deep base of technical and operational knowledge to Calumet. In recent years, Mr. Go led the integration of Flint Hills Resources’ $2 billion acquisition of PetroLogistics’ propane dehydrogenation plant; managed the operations of multiple specialty chemical plants; and established centers of operational excellence for Flint Hills Resources. Earlier in his career, Mr. Go managed ExxonMobil’s 187,000

Table of Contents

barrels-per-day Strathcona refinery in Edmonton, Canada, while also serving in a variety of operations, crude logistics and strategic planning roles for ExxonMobil in the Gulf Coast and around the world.

Strategic Update

In early 2016, we introduced a revised vision designed to position our organization as the premier specialty petroleum products company in the world. As part of this vision, we have commenced a multi-year initiative that emphasizes a combination of operational excellence, opportunistic investments in "self-help," high-return internal projects and a targeted acquisition strategy that seeks to support the purchase of complementary, competitively advantaged assets in the global specialty products markets.

Operational Excellence. We will seek to optimize our existing asset base through a series of improvement initiatives that are expected to position us for sustained, profitable growth. We have identified key areas of opportunity within the business that carry "low/no" capital investment requirements and attractive return profiles. Key initiatives under evaluation as part of the operational excellence initiative include efforts to further optimize the procurement of feedstock, efforts to improve refinery yields, efforts to improve the efficiency of assets by operating at higher utilization rates and efforts to upgrade lower margin product streams into higher margin finished products.

"Self-Help" Project Investments. We expect to pursue a series of "self-help" projects characterized by high-return investment profiles and sub-$50 million capital investment requirements. We will evaluate projects that are smaller in size and scope than the prior organic growth campaign and that carry shorter durations to completion. These projects are expected to carry high-return investment profiles capable of supporting growth in Adjusted EBITDA and Distributable Cash Flow.

Targeted Asset Strategy. We seek to acquire complementary, immediately accretive businesses with sustainable competitive advantages that further entrench us as a global leader in the specialty products markets. Our acquisition focus will include specialty businesses (1) where we have an existing core competency; and (2) that have a sustainable competitive advantage. At the same time, we regularly evaluate our portfolio to identify potential asset divestiture candidates that may not fit our core asset portfolio criteria.

Acquisitions

Acquisition	Acquisition Date	Description	Aggregate Purchase Price (1)	
Specialty Oilfield Solutions, Ltd. assets ("SOS Acquisition")	August 1, 2014	A full-service drilling fluids and solids control company with primary operations in the Eagle Ford, Marcellus and Utica shale formations.	$29.6	
ADF Holdings, Inc. ("Anchor Acquisition")	March 31, 2014	An independent provider and marketer of drilling fluids and completion fluids to the oil and gas exploration industry.	$223.6	
United Petroleum, LLC assets ("United Petroleum Acquisition")	February 28, 2014	A marketer and distributor of high performance lubricants.	$10.4	
Bel-Ray Company, LLC ("Bel-Ray Acquisition")	December 10, 2013	A manufacturer and global distributor of high-performance lubricants and greases.	$53.6	(2)
Murphy Oil USA, Inc. logistics assets ("Crude Oil Logistics Acquisition")	August 9, 2013	Crude oil loading facilities and related assets in North Dakota.	$6.2	
NuStar Energy L.P.'s San Antonio, Texas refinery ("San Antonio Acquisition")	January 2, 2013	A refinery in San Antonio, Texas with total crude oil throughput capacity of 21,000 bpd and produces jet fuel, diesel, gasoline and other fuel products and solvents.	$117.9	

(1) Aggregate purchase price is net of cash acquired and includes working capital.
(2) Aggregate purchase price is net of cash acquired and excludes debt assumed.
Key Performance Measures
Our sales and net income are principally affected by the price of crude oil, demand for specialty products, fuel products and oilfield products and services, prevailing crack spreads for fuel products, the price of natural gas used as fuel in our operations and our results from derivative instrument activities.
Our primary raw materials are crude oil and other specialty feedstocks, and our primary outputs are specialty petroleum products, fuel products and oilfield services products. The prices of crude oil, specialty products, fuel products and oilfield products and services are subject to fluctuations in response to changes in supply, demand, market uncertainties and a variety of additional factors beyond our control. We monitor these risks and enter into derivative instruments designed to help mitigate the impact of commodity price fluctuations on our business. The primary purpose of our commodity risk management activities is to economically

hedge our cash flow exposure to commodity price risk so that we can meet our cash distribution, debt service and capital expenditure requirements despite fluctuations in crude oil and fuel products prices. We enter into derivative contracts for future periods in quantities that do not exceed our projected purchases of crude oil and natural gas and sales of fuel products. Please refer to Part II, Item 7A "Quantitative and Qualitative Disclosures About Market Risk — Commodity Price Risk" for detailed information regarding our derivative instruments and our commodity price risk.
As of December 31, 2015, we have hedged refining margins, or crack spreads, on approximately 0.9 million barrels of fuel products through the first quarter of 2016 at an average refining margin of $8.98 per barrel. Please refer to Note 8 "Derivatives" under Part II, Item 8 "Financial Statements and Supplementary Data — Notes to Consolidated Financial Statements" and Part II, Item 7A "Quantitative and Qualitative Disclosures About Market Risk — Commodity Price Risk" for detailed information regarding our derivative instruments and our commodity price risk.
Our management uses several financial and operational measurements to analyze our performance. These measurements include the following:

- sales volumes;
- production yields;
- specialty products, fuel products and oilfield services segment gross profit; and
- specialty products, fuel products and oilfield services segment Adjusted EBITDA.

Sales volumes. We view the volumes of specialty products and fuel products sold as an important measure of our ability to effectively utilize our operating assets. Our ability to meet the demands of our customers is driven by the volumes of crude oil and feedstocks that we run at our facilities. Higher volumes improve profitability both through the spreading of fixed costs over greater volumes and the additional gross profit achieved on the incremental volumes.
Production yields. In order to maximize our gross profit and minimize lower margin by-products, we seek the optimal product mix for each barrel of crude oil we refine, or feedstocks we, or third parties, process, which we refer to as production yield.
Specialty products, fuel products and oilfield services segment gross profit. Specialty products, fuel products and oilfield services gross profit are important measures of our ability to maximize the profitability of our specialty products, fuel products and oilfield services segments. We define gross profit as sales less the cost of crude oil and other feedstocks and other production-related and service-related expenses, the most significant portion of which includes labor, plant fuel, utilities, contract services, maintenance, depreciation and processing materials. We use gross profit as an indicator of our ability to manage our business during periods of crude oil and natural gas price fluctuations, as the prices of our specialty products and fuel products generally do not change immediately with changes in the price of crude oil and natural gas. The increase or decrease in selling prices typically lags behind the rising or falling costs, respectively, of crude oil feedstocks for specialty products. Other than plant fuel, production-related expenses generally remain stable across broad ranges of specialty products and fuel products throughput volumes, but can fluctuate depending on maintenance activities performed during a specific period.
Our fuel products segment gross profit per barrel may differ from standard U.S. Gulf Coast, Group 3, PADD 4 Billings, Montana or 3/2/1 and 2/1/1 market crack spreads due to many factors, including derivative activities to hedge both our fuel products segment sales and the cost of crude oil reflected in gross profit, our fuel products mix as shown in our production table being different than the ratios used to calculate such market crack spreads, LCM inventory adjustments reflected in gross profit, operating costs including fixed costs, actual crude oil costs differing from market indices and our local market pricing differentials for fuel products in the Shreveport, Louisiana, San Antonio, Texas, Superior, Wisconsin and Great Falls, Montana vicinities as compared to U.S. Gulf Coast, Group 3 and PADD 4 Billings, Montana postings.
Specialty products, fuel products and oilfield services segment Adjusted EBITDA. We believe that specialty products, fuel products and oilfield services segment Adjusted EBITDA measures are useful as they exclude transactions not related to our core cash operating activities and provide metrics to analyze our ability to pay distributions to our unitholders as Adjusted EBITDA is a component in the calculation of Distributable Cash Flow and allows us to meaningfully analyze the trends and performance of our core cash operations as well as make decisions regarding the allocation of resources to segments.

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

Table of Contents

Results of Operations

The following table sets forth information about our combined operations, excluding the results of operations of our oilfield services segment. Facility production volume differs from sales volume due to changes in inventories and the sale of purchased fuel product blendstocks, such as ethanol and biodiesel, and the resale of crude oil in our fuel products segment. The table includes the results of operations at our San Antonio refinery commencing January 2, 2013, Bel-Ray facility commencing December 10, 2013 and United Petroleum assets commencing February 28, 2014:

	Year Ended December 31,		
	2015	2014	2013
	(In bpd)		
Total sales volume (1)	126,216	122,852	116,477
Total feedstock runs (2)	123,051	117,427	110,237
Facility production: (3)			
Specialty products:			
Lubricating oils	13,325	11,836	13,247
Solvents	7,942	8,934	8,759
Waxes	1,460	1,510	1,443
Packaged and synthetic specialty products (4)	1,584	1,754	1,481
Other	1,355	1,829	2,192
Total specialty products	25,666	25,863	27,122
Fuel products:			
Gasoline	37,691	34,221	29,374
Diesel	30,204	27,074	26,015
Jet fuel	5,157	4,799	4,105
Asphalt, heavy fuel oils and other	24,077	22,189	19,976
Total fuel products	97,129	88,283	79,470
Total facility production (3)	122,795	114,146	106,592

(1) Total sales volume includes sales from the production at our facilities and certain third-party facilities pursuant to supply and/or processing agreements, sales of inventories and the resale of crude oil to third party customers. Total sales volume includes the sale of purchased fuel product blendstocks, such as ethanol and biodiesel, as components of finished fuel products in our fuel products segment sales.

The increase in total sales volume in 2015 compared to 2014 is due primarily to increased production at the Shreveport refinery due to increased reliability and extended turnaround activity in 2014 and increased production at the San Antonio refinery as a result of the crude oil unit expansion completed in December 2013 being fully operational, partially offset by decreased sales of solvents and crude oil sales to third parties as a result of market conditions.

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

(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 total feedstock runs in 2015 compared to 2014 is due primarily to increased feedstock runs at the Shreveport refinery due to increased reliability and extended turnaround activity in 2014 and increased feedstock runs at the San Antonio refinery as a result of the crude oil unit expansion completed in December 2013 being fully operational, partially offset by decreased feedstock runs of solvents as a result of market conditions.

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

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. The difference between total facility production and total feedstock runs is primarily a result of the time lag between the input of feedstocks and the production of finished products and volume loss.
The increases in total facility production in 2015 over 2014 and 2014 over 2013 are due primarily to the operational items discussed above in footnote 2 of this table.

(4) Represents production of packaged and synthetic specialty products, including the products from the Royal Purple, Bel-Ray, Calumet Packaging and Missouri facilities.

The following table reflects our consolidated results of operations and includes the non-GAAP financial measures EBITDA, Adjusted EBITDA and Distributable Cash Flow. For a reconciliation of EBITDA, Adjusted EBITDA and Distributable Cash Flow to net income (loss) and net cash provided by operating activities, our most directly comparable financial performance and liquidity measures calculated and presented in accordance with GAAP, please read Item 6 “Selected Financial Data — Non-GAAP Financial Measures.”

	Year Ended December 31,		
	2015	2014	2013
	(In millions)		
Sales	$4,212.8	$5,791.1	$5,421.4
Cost of sales	3,618.2	5,261.4	5,011.4
Gross profit	594.6	529.7	410.0
Operating costs and expenses:			
Selling	146.0	149.6	62.6
General and administrative	135.5	98.3	82.1
Transportation	175.5	171.4	142.7
Taxes other than income taxes	17.7	13.4	14.2
Asset impairment	33.8	36.0	10.5
Other	11.1	14.2	6.3
Operating income	75.0	46.8	91.6
Other income (expense):			
Interest expense	(104.9)	(110.8)	(96.8)
Debt extinguishment costs	(46.6)	(89.9)	(14.6)
Realized gain (loss) on derivative instruments	8.1	43.8	(4.7)
Unrealized gain (loss) on derivative instruments	(39.5)	(0.6)	25.7
Loss from unconsolidated affiliates	(61.5)	(3.4)	(0.3)
Other	1.6	1.1	3.0
Total other expense	(242.8)	(159.8)	(87.7)
Net income (loss) before income taxes	(167.8)	(113.0)	3.9
Income tax expense (benefit)	(28.4)	(0.8)	0.4
Net income (loss)	$(139.4)	$(112.2)	$3.5
EBITDA	$129.1	$226.3	$233.1
Adjusted EBITDA	$257.7	$305.9	$241.5
Distributable Cash Flow	$161.9	$146.3	$18.8

Table of Contents

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

Sales. Sales decreased $1,578.3 million, or 27.3%, to $4,212.8 million in 2015 from $5,791.1 million in 2014. The results of operations related to the United Petroleum Acquisition has been included in the specialty products segment since its date of acquisition, February 28, 2014. The results of operations related to the Anchor and SOS Acquisitions have been included in the oilfield services segment since their dates of acquisition, March 31, 2014, and August 1, 2014, respectively. Sales for each of our principal product categories in these periods were as follows:

	Year Ended December 31,		
	2015	2014	% Change
	(In millions, except barrel and per barrel data)		
Sales by segment:			
Specialty products:			
Lubricating oils	$575.6	$748.4	(23.1)%
Solvents	302.0	485.2	(37.8)%
Waxes	136.9	144.1	(5.0)%
Packaged and synthetic specialty products [1]	316.6	313.5	1.0%
Other [2]	36.7	38.0	(3.4)%
Total specialty products	$1,367.8	$1,729.2	(20.9)%
Total specialty products sales volume (in barrels)	9,200,000	9,087,000	1.2%
Average specialty products sales price per barrel	$148.67	$190.29	(21.9)%
Fuel products:			
Gasoline	$1,002.4	$1,444.5	(30.6)%
Diesel	773.2	1,205.3	(35.8)%
Jet fuel	136.5	199.0	(31.4)%
Asphalt, heavy fuel oils and other [3]	471.0	853.6	(44.8)%
Hedging activities gain (loss)	179.4	(9.0)	2,093.3%
Total fuel products	$2,562.5	$3,693.4	(30.6)%
Total fuel products sales volume (in barrels)	36,869,000	35,754,000	3.1%
Average fuel products sales price per barrel (excluding hedging activities)	$64.64	$103.55	(37.6)%
Average fuel products sales price per barrel (including hedging activities)	$69.50	$103.30	(32.7)%
Total oilfield services	$282.5	$368.5	(23.3)%
Total sales	$4,212.8	$5,791.1	(27.3)%
Total specialty and fuel products sales volume (in barrels)	46,069,000	44,841,000	2.7%

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

(2) Represents by-products, including fuels and asphalt, produced in connection with the production of specialty products at the Princeton and Cotton Valley refineries and Dickinson and Karns City facilities.

(3) Represents asphalt, heavy fuel oils and other products produced in connection with the production of fuels at the Shreveport, Superior, San Antonio and Montana refineries and crude oil sales from the Superior and San Antonio refineries to third party customers.

Table of Contents

The components of the $361.4 million specialty products segment sales decrease in 2015 were as follows:

	Dollar Change (In millions)
Sales price	$(385.4)
Volume	19.8
Acquisition	4.2
Total specialty products segment sales decrease	$(361.4)

Specialty products segment sales for 2015 decreased $361.4 million, or 20.9%, primarily due to a decrease in the average selling price per barrel, partially offset by higher sales volume and $4.2 million of incremental sales from the United Petroleum Acquisition. Legacy operations' sales decreased $385.4 million compared to 2014 due to a 22.0% decrease in the average selling price per barrel primarily as a result of decreased lubricating oils, solvents and packaged and synthetic specialty products average selling prices due to market conditions, while the average cost of crude oil per barrel decreased 46.2%. The increase in sales volume is due primarily to higher sales volume of lubricating oils at the Shreveport refinery due to increased production reliability in 2015 and extended turnaround activity in 2014 and increased sales volume of packaged and synthetic specialty products, partially offset by decreased sales volume of solvents due to market conditions.

The components of the $1,130.9 million fuel products segment sales decrease in 2015 were as follows:

	Dollar Change (In millions)
Sales price	$(1,440.9)
Hedging activities	188.4
Volume	121.6
Total fuel products segment sales decrease	$(1,130.9)

Fuel products segment sales for 2015 decreased $1,130.9 million, or 30.6%, due primarily to a decrease in the average selling price per barrel, partially offset by a $188.4 million decrease in realized derivative losses recorded in sales on our fuel products cash flow hedges and increased sales volume. The average selling price per barrel (excluding the impact of hedging activities reflected in sales) decreased $38.91, or 37.6%, resulting in a $1,440.9 million decrease in sales, compared to a 47.0% decrease in the average price of crude oil per barrel. The decrease in the average selling price per barrel is primarily due to market conditions. Sales volume increased 3.1% primarily due to increased production reliability in 2015 and extended turnaround activity in 2014 at the Shreveport refinery and increased production at the San Antonio refinery as a result of the crude oil unit expansion completed in December 2013 being fully operational, partially offset by decreased crude oil sales to third parties.

Oilfield services segment sales for 2015 decreased $86.0 million, or 23.3%, primarily due to decreased sales volume driven by a decline in rig count, partially offset by $93.4 million of incremental sales from the Anchor and SOS Acquisitions completed in 2014. Our rig count decreased 46.5% as a result of a 47.8% decrease in the U.S. land-based rig count. Currently, we sell to approximately 10% of the U.S. land-based rigs. Volatility in crude oil and natural gas prices impacted our customers' drilling and production activities during 2015, which resulted in an unfavorable impact on sales in 2015.

Table of Contents

Gross Profit. Gross profit increased $64.9 million, or 12.3%, to $594.6 million in 2015 from $529.7 million in 2014. Gross profit for our specialty, fuel products and oilfield services segments was as follows:

	Year Ended December 31,		
	2015	2014	% Change
	(Dollars in millions, except per barrel data)		
Gross profit by segment:			
Specialty products:			
Gross profit	$370.2	$373.2	(0.8)%
Percentage of sales	27.1%	21.6%	
Specialty products gross profit per barrel	$40.24	$41.07	(2.0)%
Fuel products:			
Gross profit excluding hedging activities	$157.1	$(0.7)	22,542.9%
Hedging activities	9.1	35.2	(74.1)%
Gross profit	$166.2	$34.5	381.7%
Percentage of sales	6.5%	0.9%	
Fuel products gross profit (loss) per barrel (excluding hedging activities)	$4.26	$(0.02)	21,400.0%
Fuel products gross profit per barrel (including hedging activities)	$4.51	$0.96	369.8%
Oilfield services:			
Gross profit	$58.2	$122.0	(52.3)%
Percentage of sales	20.6%	33.1%	
Total gross profit	$594.6	$529.7	12.3%
Percentage of sales	14.1%	9.1%	

The components of the $3.0 million decrease in the specialty products segment gross profit for 2015 were as follows:

	Dollar Change
	(In millions)
2014 reported gross profit	$373.2
Cost of materials	415.6
Volume	6.5
Acquisition	1.0
Sales price	(385.4)
LCM inventory adjustment	(34.9)
LIFO inventory layer adjustment	(5.8)
2015 reported gross profit	$370.2

The decrease in specialty products segment gross profit of $3.0 million year over year was due primarily to a decrease in the average selling price per barrel and a $34.9 million increase in the unfavorable LCM inventory adjustment primarily as a result of the lower crude oil prices, partially offset by decreased cost of materials and increased sales volume. Sales price and cost of materials, net, from our legacy operations increased gross profit by $30.2 million, as the average selling price per barrel decreased 22.0%, while the average cost of crude oil per barrel decreased 46.2%. Gross profit was also negatively impacted by increased losses of $5.8 million related to the liquidation of LIFO inventory layers.

Table of Contents

The components of the $131.7 million increase in the fuel products segment gross profit for 2015 were as follows:

	Dollar Change (In millions)
2014 reported gross profit	$34.5
Cost of materials	1,561.2
LCM inventory adjustment	42.0
LIFO inventory layer adjustment	12.5
Volume	10.8
Operating costs	1.6
Sales price	(1,440.9)
RINs, net	(29.4)
Hedging activities	(26.1)
2015 reported gross profit	$166.2

The increase in fuel products segment gross profit of $131.7 million year over year was due primarily to widening gasoline crack spreads and asphalt margins, a $42.0 million decrease in the unfavorable LCM inventory adjustment and decreased losses of $12.5 million related to the liquidation of LIFO inventory layers, partially offset by a $29.4 million unfavorable RINs adjustment and a $26.1 million decrease in realized gains on derivatives. During 2015, crack spreads widened as the average cost of crude oil per barrel decreased 47.0% and the average selling price per barrel decreased by 37.6%. The $29.4 million unfavorable RINs adjustment primarily resulted from increased RINs market pricing.

The decrease in oilfield services segment gross profit of $63.8 million year over year was due primarily to decreased sales volume driven by a decline in rig count and a $14.8 million unfavorable LCM adjustment, partially offset by $26.9 million of incremental gross profit from the Anchor and SOS Acquisitions completed in 2014. Volatility in crude oil and natural gas prices impacted our customers' drilling and production activities, which had an unfavorable impact on our gross profit in 2015. The continued decrease in crude oil prices created tighter market conditions in the basins in which we operate.

Selling. Selling expenses decreased $3.6 million, or 2.4%, to $146.0 million in 2015 from $149.6 million in 2014. The decrease was due primarily to a $5.6 million decrease in advertising expense and a $2.0 million decrease in travel and entertainment expense, partially offset by incremental selling expenses related to the Anchor and SOS Acquisitions and a $0.8 million increase in bad debt expense.

General and administrative. General and administrative expenses increased $37.2 million, or 37.8%, to $135.5 million in 2015 from $98.3 million in 2014. The increase was due primarily to incremental general and administrative expenses related to the Anchor and SOS Acquisitions, a $12.2 million increase in incentive compensation costs, an $8.5 million increase in professional fees expense, a $4.6 million legal settlement and a $2.9 million increase in severance expenses.

Transportation. Transportation expenses increased $4.1 million, or 2.4%, to $175.5 million in 2015 from $171.4 million in 2014. This increase is due primarily to increased sales of lubricating oils and packaged and synthetic specialty products and incremental transportation expenses related to the Anchor and SOS Acquisitions, partially offset by decreased crude oil sales to third parties and decreased freight rates.

Asset impairment. During 2015, we recorded an impairment charge of $33.8 million related to the oilfield services segment compared to an impairment charge of $36.0 million in 2014. The impairment charges were driven primarily by our reduced outlook on revenues and profitability as a result of the continued decline of crude oil prices.

Interest expense. Interest expense decreased $5.9 million, or 5.3%, to $104.9 million in 2015 from $110.8 million in 2014. The decrease is due primarily to increased capitalized interest and lower interest rates on outstanding senior notes, partially offset by increased outstanding long-term debt.

Debt extinguishment costs. Debt extinguishment costs decreased $43.3 million, or 48.2%, to $46.6 million in 2015, due primarily to the redemption of the 2020 Notes with a portion of the net proceeds from the issuance of the 2023 Notes in 2015 compared to the redemption of the remaining 9.375% senior notes due 2019 ("2019 Notes") with a portion of the net proceeds from the issuance of the 2021 Notes in 2014.

Table of Contents

Derivative activity. The following table details the impact of our derivative instruments on the consolidated statements of operations for 2015 and 2014:

	Year Ended December 31,	
	2015	2014
	(In millions)	
Derivative gain (loss) reflected in sales	$179.4	$(9.0)
Derivative gain (loss) reflected in cost of sales	(167.3)	46.0
Derivative gain reflected in gross profit	$12.1	$37.0
Realized gain on derivative instruments	$8.1	$43.8
Unrealized loss on derivative instruments	(39.5)	(0.6)
Derivative gain reflected in interest expense	0.5	3.3
Total derivative gain (loss) reflected in the consolidated statements of operations	$(18.8)	$83.5
Total gain on commodity derivative settlements	$10.2	$87.5

Realized gain on derivative instruments. Realized gain on derivative instruments decreased $35.7 million to $8.1 million in 2015 from $43.8 million in 2014. The change was due primarily to decreased realized gains of approximately $12.9 million related to settlements of derivative instruments used to economically hedge crack spreads and crude oil that are not classified as hedges for accounting purposes, decreased realized gains of approximately $11.8 million on natural gas swaps used to economically hedge natural gas purchases and decreased gain ineffectiveness of approximately $10.9 million, partially offset by a $1.7 million gain associated with premiums received for crude oil option contracts in the 2015 period.

Unrealized loss on derivative instruments. Unrealized loss on derivative instruments increased $38.9 million to $39.5 million in 2015 from $0.6 million in 2014. This change was due primarily to decreased unrealized gains of approximately $52.3 million related to derivative instruments used to economically hedge crack spreads, crude oil and natural gas that are not accounted for as hedges for accounting purposes, partially offset by ineffectiveness of approximately $13.4 million in 2014 with no comparable activity in the current period.

Loss from unconsolidated affiliates. Loss from unconsolidated affiliates increased $58.1 million to $61.5 million in 2015 from $3.4 million in 2014, due primarily to unfavorable operating results of Dakota Prairie, which commenced sales to third parties in May 2015 and a $24.3 million other-than-temporary impairment charge related to Juniper (defined below).

Income tax benefit. Income tax benefit increased $27.6 million to $28.4 million in 2015 from $0.8 million in 2014. The change was due primarily to weaker performance in our oilfield services segment, including a $33.8 million goodwill impairment charge and a $14.8 million LCM inventory adjustment, which increased the proportion of losses subject to federal, state and local income taxes and the conversion of ADF Holdings, Inc. to ADF Holdings, LLC and Anchor Drilling Fluids USA, Inc. to Anchor Drilling Fluids USA, LLC, which resulted in the writeoff of deferred taxes.

Table of Contents

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

Sales. Sales increased $369.7 million, or 6.8%, to $5,791.1 million in 2014 from $5,421.4 million in 2013. The results of operations related to the San Antonio and Crude Oil Logistics Acquisitions have been included in the fuel products segment since their dates of acquisition, January 2, 2013, and August 9, 2013, respectively. The results of operations related to the Bel-Ray and United Petroleum Acquisitions have been included in the specialty products segment since their dates of acquisition, December 10, 2013, and February 28, 2014, respectively. The results of operations related to the Anchor and SOS Acquisitions have been included in the oilfield services segment since their dates of acquisition, March 31, 2014, and August 1, 2014, respectively. Sales for each of our principal product categories in these periods were as follows:

	Year Ended December 31,		
	2014	2013	% Change
	(In millions, except barrel and per barrel data)		
Sales by segment:			
Specialty products:			
Lubricating oils	$748.4	$848.8	(11.8)%
Solvents	485.2	511.7	(5.2)%
Waxes	144.1	141.0	2.2%
Packaged and synthetic specialty products (1)	313.5	233.6	34.2%
Other (2)	38.0	39.8	(4.5)%
Total specialty products	$1,729.2	$1,774.9	(2.6)%
Total specialty products sales volume (in barrels)	9,087,000	9,630,000	(5.6)%
Average specialty products sales price per barrel	$190.29	$184.31	3.2%
Fuel products:			
Gasoline	$1,444.5	$1,409.8	2.5%
Diesel	1,205.3	1,263.2	(4.6)%
Jet fuel	199.0	190.1	4.7%
Asphalt, heavy fuel oils and other (3)	853.6	786.5	8.5%
Hedging activities loss	(9.0)	(3.1)	190.3%
Total fuel products	$3,693.4	$3,646.5	1.3%
Total fuel products sales volume (in barrels)	35,754,000	32,884,000	8.7%
Average fuel products sales price per barrel (excluding hedging activities)	$103.55	$110.98	(6.7)%
Average fuel products sales price per barrel (including hedging activities)	$103.30	$110.89	(6.8)%
Total oilfield services	$368.5	$—	—
Total sales	$5,791.1	$5,421.4	6.8%
Total specialty and fuel products sales volume (in barrels)	44,841,000	42,514,000	5.5%

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

(2) Represents by-products, including fuels and asphalt, produced in connection with the production of specialty products at the Princeton and Cotton Valley refineries and Dickinson and Karns City facilities.

(3) Represents asphalt, heavy fuel oils and other products produced in connection with the production of fuels at the Shreveport, Superior, San Antonio and Montana refineries and purchased crude oil sales from the Superior and San Antonio refineries to third party customers.

67

Table of Contents

The components of the $45.7 million specialty products segment sales decrease in 2014 were as follows:

	Dollar Change (In millions)
Acquisitions	$58.1
Sales price	17.8
Volume	(121.6)
Total specialty products segment sales decrease	$(45.7)

Specialty products segment sales for 2014 decreased $45.7 million, or 2.6%, primarily as a result of lower sales volume, partially offset by $58.1 million incremental sales from the Bel-Ray and United Petroleum Acquisitions and an increase in the average selling price per barrel. Legacy operations' sales increased $17.8 million compared to 2013 due to a 1.1% increase in the average selling price per barrel primarily as a result of higher lubricating oil sales prices and improved product mix. Legacy operations' sales volumes decreased 6.8% as compared to 2013, which resulted in a $121.6 million decrease in sales. The decrease in sales volume is due primarily to lower sales volumes of lubricating oils and solvents due to market conditions, partially offset by increased sales volumes of packaged and synthetic specialty products.

The components of the $46.9 million fuel products segment sales increase in 2014 were as follows:

	Dollar Change (In millions)
Volume	$318.5
Hedging activities	(5.9)
Sales price	(265.7)
Total fuel products segment sales increase	$46.9

Fuel products segment sales for 2014 increased $46.9 million, or 1.3%, due primarily to increased volume, partially offset by a decrease in the average selling price per barrel and a $5.9 million increase in realized derivative losses recorded in sales on our fuel products cash flow hedges. Sales volumes increased 8.7% primarily due to increased sales volume of gasoline, jet fuel and asphalt primarily as a result of increased production at the Superior and Montana refineries due to turnaround activity in 2013 and increased production at the San Antonio refinery as a result of the crude oil unit expansion completed in December 2013, partially offset by extended turnaround activity in 2014 at the Shreveport refinery. The average selling price per barrel (excluding the impact of hedging activities reflected in sales) decreased $7.43, or 6.7%, resulting in a $265.7 million decrease in sales, compared to a 6.3% decrease in the average price of crude oil per barrel. The average selling price per barrel decreased across all fuel products categories as a result of lower crude oil prices.

Oilfield services segment sales for 2014 increased $368.5 million as a result of the Anchor and SOS Acquisitions in 2014. Volatility in crude oil and natural gas prices impacted our customers' drilling and production activities, which resulted in an unfavorable impact to our sales late in 2014. The U.S. onshore rig count decreased 6% from the third quarter of 2014 to the fourth quarter of 2014. As of December 31, 2014, we sold to approximately 10% of the U.S. land-based rigs.

Table of Contents

Gross Profit. Gross profit increased $119.7 million, or 29.2%, to $529.7 million in 2014 from $410.0 million in 2013. Gross profit for our specialty, fuel products and oilfield services segments was as follows:

	Year Ended December 31,		
	2014	2013	% Change
	(Dollars in millions, except per barrel data)		
Gross profit by segment:			
Specialty products:			
Gross profit	$373.2	$322.3	15.8 %
Percentage of sales	21.6 %	18.2 %	
Specialty products gross profit per barrel	$41.07	$33.47	22.7 %
Fuel products:			
Gross profit excluding hedging activities	$(0.7)	$87.7	(100.8)%
Hedging activities	35.2	—	100.0 %
Gross profit	$34.5	$87.7	(60.7)%
Percentage of sales	0.9 %	2.4 %	
Fuel products gross profit (loss) per barrel (excluding hedging activities)	$(0.02)	$2.67	(100.7)%
Fuel products gross profit per barrel (including hedging activities)	$0.96	$2.67	(64.0)%
Oilfield services:			
Gross profit	$122.0	$—	—
Percentage of sales	33.1 %	—	
Total gross profit	$529.7	$410.0	29.2 %
Percentage of sales	9.1 %	7.6 %	

The components of the $50.9 million specialty products segment gross profit increase in 2014 were as follows:

	Dollar Change
	(In millions)
2013 reported gross profit	$322.3
Cost of materials	60.0
Sales price	17.8
Acquisitions	18.1
Operating costs	(3.0)
LCM inventory adjustment	(1.1)
LIFO inventory layer liquidation	(6.3)
Volume	(34.6)
2014 reported gross profit	$373.2

The increase in specialty products segment gross profit of $50.9 million year over year was due primarily to the decreased cost of feedstocks, higher sales price per barrel and incremental gross profit of $18.1 million generated from the Bel-Ray and United Petroleum Acquisitions, partially offset by decreased sales volume. Sales price and cost of materials, net, from our legacy operations increased gross profit by $77.8 million. The cost of materials decrease was primarily a result of the 7.8% decrease in the average cost of crude oil per barrel and decreased cost of base oil feedstocks per barrel. Gross profit was negatively impacted by a $1.1 million LCM inventory adjustment and decreased gains of $6.3 million related to the liquidation of LIFO inventory layers.

The components of the $53.2 million fuel products segment gross profit decrease in 2014 were as follows:

	Dollar Change (In millions)
2013 reported gross profit	$87.7
Sales price	(265.8)
LCM inventory adjustment	(75.0)
Operating costs	(31.5)
LIFO inventory layer liquidation	(29.8)
Cost of materials	257.9
Volume	35.6
Hedging activities	35.2
RINs, net	20.2
2014 reported gross profit	$34.5

The decrease in fuel products segment gross profit of $53.2 million year over year was due primarily to narrowing crack spreads and increased operating costs, partially offset by increased realized gains on derivatives of $35.2 million. Sales price and cost of materials, net, decreased gross profit by $7.9 million, as the average selling price per barrel decreased 6.7%, while the average cost of crude oil per barrel decreased 6.3%. Gross profit was negatively impacted by a $75.0 million LCM inventory adjustment and increased losses of $29.8 million related to the liquidation of LIFO inventory layers. Operating costs increased $31.5 million primarily as a result of higher repairs and maintenance, depreciation and natural gas costs, partially offset by an $18.2 million gain on RINs from the sale of approximately 31 million RINs as a result of receiving approval from the EPA of a one-year extension of the small refinery exemption from the requirements of the RFS for our Shreveport and San Antonio refineries for the 2013 calendar year.

The increase in oilfield services segment gross profit of $122.0 million year over year was due to the Anchor and SOS Acquisitions in 2014. Volatility in crude oil and natural gas prices impacted our customers' drilling and production activities, which resulted in an unfavorable impact to our gross profit late in 2014. The decrease in crude oil prices created tighter market conditions in the basins in which we operate.

Selling. Selling expenses increased $87.0 million, or 139.0%, to $149.6 million in 2014 from $62.6 million in 2013. This decrease was due primarily to incremental selling expenses related to the Anchor, Bel-Ray and SOS Acquisitions, a $1.7 million increase in advertising expense and a $0.7 million increase in professional fees expense.

General and administrative. General and administrative expenses increased $16.2 million, or 19.7%, to $98.3 million in 2014 from $82.1 million in 2013. The increase was due primarily to incremental general and administrative expenses related to the Anchor, Bel-Ray and SOS Acquisitions, a $6.1 million increase in incentive compensation costs, a $2.6 million increase in information technology related expenses and a $1.5 million increase in professional fees expense.

Transportation. Transportation expenses increased $28.7 million, or 20.1%, to $171.4 million in 2014 from $142.7 million in 2013. This increase is due primarily to incremental transportation expenses related to the Anchor, Bel-Ray and SOS Acquisitions and increased crude oil sales to third parties, partially offset by decreased lubricating oil sales.

Other operating costs and expenses. Other operating costs and expenses increased $7.9 million, or 125.4%, to $14.2 million in 2014 from $6.3 million in 2013. The increase was due primarily to increased environmental remediation expenses.

Interest expense. Interest expense increased $14.0 million, or 14.5%, to $110.8 million in 2014 from $96.8 million in 2013. The increase is due primarily to additional outstanding long-term debt in the form of 2022 Notes (as defined below), 2021 Notes (as defined below) and borrowings under our revolving credit facility, partially offset by lower interest expense resulting from the redemption of the 2019 Notes.

Asset impairment. During 2014, we recorded an impairment charge of $36.0 million related to the oilfield services segment. The impairment was driven primarily by our reduced outlook on revenues and profitability as a result of the extreme fluctuations in crude oil prices during the fourth quarter of 2014.

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

Table of Contents

Please read Note 7 “Long-Term Debt” to our consolidated financial statements in Part II, Item 8 “Financial Statements and Supplementary Data” for additional information.

Derivative activity. The following table details the impact of our derivative instruments on the consolidated statements of operations for 2014 and 2013:

	Year Ended December 31,	
	2014	2013
	(In millions)	
Derivative loss reflected in sales	$(9.0)	$(3.1)
Derivative gain reflected in cost of sales	46.0	3.6
Derivative gain reflected in gross profit	$37.0	$0.5
Realized gain (loss) on derivative instruments	$43.8	$(4.7)
Unrealized gain (loss) on derivative instruments	(0.6)	25.7
Derivative gain reflected in interest expense	3.3	—
Total derivative gain reflected in the consolidated statements of operations	$83.5	$21.5
Total gain (loss) on commodity derivative settlements	$87.5	$(6.0)

Realized gain (loss) on derivative instruments. Realized gain (loss) on derivative instruments decreased $48.5 million to a gain of $43.8 million in 2014 from a loss of $4.7 million in 2013. The change was due primarily to increased realized gains of approximately $22.8 million related to settlements of derivative instruments used to economically hedge crack spreads that are not classified as hedges for accounting purposes, increased realized gains of approximately $13.4 million on crude oil basis swaps used to economically hedge crude oil purchases and increased realized gains of $9.9 million related to ineffectiveness on settlements of cash flow hedges.

Unrealized gain (loss) on derivative instruments. Unrealized gain (loss) on derivative instruments decreased $26.3 million to a loss of $0.6 million in 2014 from a gain of $25.7 million in 2013. This change was due primarily to increased unrealized loss ineffectiveness of approximately $41.6 million, partially offset by increased unrealized gains of $15.5 million related to derivative instruments used to economically hedge crack spreads and natural gas that are not accounted for as hedges for accounting purposes.

Income tax expense (benefit). Income tax expense (benefit) decreased $1.2 million to a benefit of $0.8 million in 2014 from an expense of $0.4 million in 2013. The change was due primarily to the Anchor Acquisition, which increased the proportion of losses subject to federal, state and local income taxes.

Liquidity and Capital Resources

Our principal sources of cash have historically included cash flow from operations, proceeds from public equity offerings, proceeds from notes offerings and bank borrowings. Principal uses of cash have included capital expenditures, acquisitions, distributions to our limited partners and general partner and debt service. We expect that our principal uses of cash in the future will be for distributions to our 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, borrowings under our revolving credit facility and by accessing capital markets as necessary. Future internal growth projects or acquisitions may require expenditures in excess of our then-current cash flow from operations and borrowing availability under our existing revolving credit facility and may require us to issue debt or equity securities in public or private offerings or incur additional borrowings under bank credit facilities to meet those costs. We may from time to time seek to retire or purchase our outstanding debt through cash purchases and/or exchanges for equity securities, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

The borrowing base on our revolving credit facility declined from $575.9 million as of December 31, 2014, to $411.3 million at December 31, 2015, resulting in a corresponding decrease in our borrowing availability from $310.8 million at December 31, 2014, to $233.5 million at December 31, 2015. The decline in the borrowing base on our revolving credit facility was attributable to pronounced volatility in the price of crude oil, which declined by approximately 47% during the course of 2015, versus the prior year. As the price of crude oil declined, the value of crude oil and product inventories used as collateral under our revolving credit facility also declined, resulting in a reduction in the borrowing base.

In response to current commodity price volatility, we have taken or currently are taking the following steps to mitigate the impact of such volatility on our operating results:

- we entered into an agreement with The Heritage Group ("Heritage"), an affiliate of our general partner, in which Heritage made a $27.0 million uncommitted prepayment for the purchase of certain fuel products and entered into a $48.0 million unsecured note payable with us as the borrower;
- given the increased market value of certain of our derivative assets, our risk management committee approved the early settlement of select calendar year 2016 derivative instruments. As a result of the settlement of these derivative assets, we received approximately $22.3 million during the fourth quarter of 2015;
- we remain committed to an active hedging program to manage commodity price risk in our business. Due to the volatility of the price of crude oil and the impact such volatility has had on our short-term cash flows, we may use derivative instruments, primarily combinations of options or swaps, to mitigate our exposure to changes in crude oil prices and the impact to our borrowing base. We continue to consider current crude oil prices, specialty products and fuel products gross profit expectations and liquidity as the primary factors to determine the volume, time horizon and type of derivative instruments we may execute. Due to the current economic environment and the complexities around derivative instruments, we intend to maintain flexibility in the manner in which we hedge;
- we have deferred certain non-critical capital expenditures until the third and fourth quarters of 2016;
- we continue to implement strategies to reduce our working capital requirements across all of our operations and we expect to maintain prudent levels of working capital to enhance liquidity; and
- we have entered into certain leasing arrangements versus purchasing assets to improve our cash flows.

Cash Flows from Operating, Investing and Financing Activities

We believe that we have sufficient liquid assets, cash flow from operations, borrowing capacity and adequate access to capital markets to meet our financial commitments, debt service obligations and anticipated capital expenditures. However, we are subject to business and operational risks that could materially adversely affect our cash flows. A material decrease in our cash flow from operations including a significant, sudden decrease in crude oil prices would likely produce a corollary material adverse effect on our borrowing capacity under our revolving credit facility and potentially our ability to comply with the covenants under our revolving credit facility. A significant, sudden increase in crude oil prices, if sustained, would likely result in increased working capital requirements which would be funded by borrowings under our revolving credit facility. In addition, our cash flow from operations may be impacted by the timing of settlement of our derivative activities. Gains and losses from derivative instruments that qualify as effective cash flow hedges are deferred in accumulated other comprehensive income (loss), but may impact operating cash flow in the period settled. Gains and losses from derivative instruments that do not qualify as hedges are recorded in unrealized gain (loss) until settlement and will impact operating cash flow in the period settled.

The following table summarizes our primary sources and uses of cash in each of the most recent three years:

	Year Ended December 31,		
	2015	2014	2013
	(In millions)		
Net cash provided by operating activities	$376.4	$226.8	$39.1
Net cash used in investing activities	(389.0)	(658.8)	(370.3)
Net cash provided by financing activities	9.7	319.4	420.1
Net increase (decrease) in cash and cash equivalents	$(2.9)	$(112.6)	$88.9

Operating Activities. Operating activities provided cash of $376.4 million during 2015 compared to $226.8 million during 2014. The increase in cash provided by operating activities is due primarily to decreased working capital requirements in 2015 providing $117.9 million compared to 2014 working capital requirements providing $25.1 million as well as an increase in operating cash flows of $84.0 million, partially offset by an increased net loss of $27.2 million. Working capital improvements were primarily driven by decreased accounts receivable and inventories. Operating activities provided $226.8 million in cash during 2014 compared to $39.1 million during 2013. The increase in cash provided by operating activities is due primarily to decreased working capital requirements in 2014 providing $25.1 million, compared to 2013 working capital requirements using $101.4 million as well as an increase in operating cash flows of $176.9 million, partially offset by decreased net income of $115.7 million. Working capital improvements were primarily driven by decreased inventories, accounts receivable and turnaround costs, $44.8 million related to the early settlement of certain crack spread derivative instruments and a gain on sales of RINs of $18.2 million.

Investing Activities. Cash used in investing activities decreased to $389.0 million in 2015 compared to $658.8 million in 2014. The decrease is due primarily to the higher combined purchase price of $263.6 million for the Anchor, United Petroleum and SOS Acquisitions, which closed in 2014, with no similar activity in 2015, a decrease in net joint venture investments to the

Dakota Prairie Refining, LLC and Juniper GTL LLC joint ventures of $55.2 million, partially offset by an increase in capital expenditures of $49.4 million due primarily to the capital improvement projects discussed below.
Cash used in investing activities increased to $658.8 million in 2014 compared to $370.3 million in 2013. The increase is due primarily to the higher combined purchase price of $263.6 million for the United Petroleum, Anchor and SOS Acquisitions, which closed in 2014 compared to a combined purchase price of $177.7 million for the San Antonio, Crude Oil Logistics and Bel-Ray Acquisitions in 2013, an increase in capital expenditures of $129.1 million due primarily to the capital improvement projects discussed below and $105.4 million contributed to the Dakota Prairie Refining, LLC and Juniper GTL LLC joint ventures.
Financing Activities. Financing activities provided cash of $9.7 million during 2015 compared to $319.4 million during 2014. This decrease is due primarily to decreased net proceeds from the private placements of senior notes of $563.1 million, repayments of $39.8 million on the revolving credit facility in 2015 compared to use of $150.8 million of net proceeds from revolving credit facility borrowings in 2014 and increased distributions of $14.4 million. Partially offsetting these decreases are the redemption of the 2019 Notes of $500.0 million in 2014 compared to the redemption of the 2020 Notes of $275.0 million in 2015, an increase in net proceeds from public offerings of common units (including our general partner’s contributions) of $163.9 million and $75.0 million of proceeds from a related party note payable.
Financing activities provided cash of $319.4 million during 2014 compared to $420.1 million during 2013. The decrease is due primarily to the redemption of the remaining 2019 Notes of $500.0 million, a decrease in net proceeds from public offerings of common units (including our general partner’s contributions) of $397.2 million and increased distributions to our unitholders of $8.6 million. Partially offsetting these decreases are increased net proceeds from the private placement of senior notes of $555.3 million and increased revolving credit facility borrowings of $150.8 million.
Acquisitions
Acquisitions impact our results of operations commencing on the closing date of each acquisition. Our acquisitions are discussed further in Note 3 “Acquisitions” in the notes to our consolidated financial statements under Part II, Item 8 “Financial Statements and Supplementary Data.” Information regarding acquisitions completed in 2015, 2014 and 2013 is set forth in the table below (in millions):

Acquisition	Closing Date	Purchase Price	Funding Methods	Segment
United Petroleum	February 28, 2014	$10.4	Cash on hand	Specialty Products
Anchor	March 31, 2014	223.6	Net proceeds from our March 2014 private placement of 2021 Notes	Oilfield Services
SOS	August 1, 2014	29.6	Borrowings under our revolving credit facility	Oilfield Services
2014 Total		$263.6		
San Antonio	January 2, 2013	$117.9	Borrowings under our revolving credit facility	Fuel Products
Crude Oil Logistics Assets	August 9, 2013	6.2	Cash on hand	Fuel Products
Bel-Ray	December 10, 2013	53.6	Net proceeds from our November 2013 private placement of 2022 Notes	Specialty Products
2013 Total		$177.7		

Joint Ventures
Dakota Prairie Refining, LLC
On February 7, 2013, we entered into a joint venture agreement with MDU Resources Group, Inc. (“MDU”) to develop, build and operate a diesel refinery in southwestern North Dakota. The joint venture is named Dakota Prairie Refining, LLC (“Dakota Prairie”). The capitalization of the construction cost was funded through cash contributions from MDU,

cash contributions from us and proceeds of $75.0 million from a syndicated term loan facility with the joint venture as the borrower, which is expected to be repaid by us through our allocation of profits from the joint venture. The term loan facility was funded in April 2013. In addition to the $300.0 million commitment outlined in the joint venture agreement, we and MDU made additional cash contributions, net of distributions, in the amount of $88.6 million and $80.4 million, respectively, to fund construction costs and working capital needs. Additionally, we and MDU may make cash contributions to fund working capital needs. The joint venture allocates profits on a 50%/50% basis to us and MDU, except for the adjustments made to our share for repayment of the principle and interest of the $75.0 million term loan as noted above. The joint venture is governed by a board of managers comprised of representatives from both us and MDU. MDU is providing natural gas and electricity utility services. We are providing refinery operations, crude oil procurement and refined product marketing expertise to the joint venture. Dakota Prairie commenced sales of finished products in May 2015. As of December 31, 2015 and 2014, we have an investment of $124.7 million and $117.2 million, respectively, in Dakota Prairie.

Table of Contents

Juniper GTL LLC

On June 9, 2014, we entered into a joint venture agreement with Clean Fuels North America, LLC, which is owned by SGC Energia and Great Northern Project Development, to develop, build and operate a gas-to-liquids (“GTL”) plant in Lake Charles, Louisiana. The joint venture is named New Source Fuels, LLC, and it owns 100% of Juniper GTL LLC (“Juniper”). We invested $25.0 million in total in exchange for an equity interest of approximately 23% in the joint venture. During the third quarter of 2015, we determined the fair value of our investment in Juniper was less than its carrying value of $24.3 million. As a result, we recorded a $24.3 million impairment charge in loss from unconsolidated affiliates in the consolidated statement of operations for the year ended December 31, 2015.

Capital Expenditures

Our property, plant and equipment capital expenditure requirements consist of capital improvement expenditures, replacement capital expenditures and environmental capital expenditures. Capital improvement expenditures include expenditures to acquire assets to grow our business, to expand existing facilities, such as projects that increase operating capacity, or to reduce operating costs. Replacement capital expenditures replace worn out or obsolete equipment or parts. Environmental capital expenditures include asset additions to meet or exceed environmental and operating regulations. Turnaround capital expenditures represent capitalized costs associated with our periodic major maintenance and repairs.

The following table sets forth our capital improvement expenditures, replacement capital expenditures, environmental capital expenditures, turnaround capital expenditures and joint venture contributions in each of the periods shown (including capitalized interest):

	Year Ended December 31,		
	2015	2014	2013
	(In millions)		
Capital improvement expenditures	$311.7	$284.9	$109.7
Replacement capital expenditures	28.9	18.8	33.8
Environmental capital expenditures	15.3	13.0	30.4
Turnaround capital expenditures	19.3	27.6	68.6
Joint venture contributions, net of return of investment	50.2	105.4	31.8
Total	$425.4	$449.7	$274.3

We anticipate that future capital expenditure requirements will be provided primarily through cash flow from operations, cash on hand, available borrowings under our revolving credit facility and by accessing capital markets as necessary. If future capital expenditures require expenditures in excess of our then-current cash flow from operations and borrowing availability under our existing revolving credit facility, we may be required to issue debt or equity securities in public or private offerings or incur additional borrowings under bank credit facilities to meet those costs.

We estimate our replacement and environmental capital expenditures will be $50.0 million to $60.0 million in 2016. These estimated amounts for 2016 include a portion of the $3.0 million to $5.0 million in environmental projects to be spent as required by our settlement with the LDEQ under the “Small Refinery and Single Site Refining Initiative.” Please read Part I, Items 1 and 2 “Business and Properties — Environmental and Occupational Health and Safety Matters — Air Emissions” for additional information.

We estimate we will spend approximately $60.0 million to $70.0 million in 2016 on capital investment in growth projects. Our primary capital improvements projects in 2015 included the following:

- Montana Refinery Expansion — In February 2016, we completed an expansion project that increased production capacity at our Montana refinery by 15,000 bpd to 25,000 bpd.
- Dakota Prairie Refining, LLC — Dakota Prairie, a 20,000 bpd diesel refinery in southwestern North Dakota, was commissioned in April 2015 and commenced sales of finished products in May 2015.

We estimate turnaround spending requirements will be $5.0 million to $10.0 million for 2016 primarily related to scheduled turnaround activity at our Shreveport refinery. We expect these expenditures will be funded primarily through cash flow from operations. During 2015, we spent approximately $19.3 million primarily related to scheduled turnaround activities at our Shreveport, San Antonio and Princeton refineries, funded through cash flow from operations and borrowings under our revolving credit facility.

Table of Contents

Debt and Credit Facilities

As of December 31, 2015, our primary debt and credit instruments consisted of:

- a $1.0 billion senior secured revolving credit facility maturing in July 2019, subject to borrowing base limitations, with a maximum letter of credit sublimit equal to $600.0 million, which amount may be increased to 90% of revolver commitments in effect with the consent of the Agent (as defined in the revolving credit agreement) (“revolving credit facility”);
- $900.0 million of 6.50% senior notes due 2021 (“2021 Notes”);
- $350.0 million of 7.625% senior notes due 2022 (“2022 Notes”);
- $325.0 million of 7.75% senior notes due 2023 (“2023 Notes”); and
- $73.5 million related party note payable.

On April 27, 2015, we redeemed $96.2 million aggregate principal amount outstanding of 9.625% Senior Notes due August 1, 2020 (“2020 Notes”), with a portion of the net proceeds of the March 13, 2015, public offering of our common units in which we sold 6,000,000 common units. Additionally, on April 28, 2015, we redeemed the remaining $178.8 million aggregate principal amount outstanding of 2020 Notes with a portion of the net proceeds from the issuance of the 2023 Notes.

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

Short Term Liquidity

As of December 31, 2015, our principal sources of short-term liquidity were (i) $233.5 million of availability under our revolving credit facility and (ii) $5.6 million of cash. Borrowings under our revolving credit facility can be used for, among other things, working capital, capital expenditures, and other lawful partnership purposes including acquisitions.

Borrowings under the revolving credit facility are limited to a borrowing base that is determined based on advance rates of percentages of Eligible Accounts Receivable and Eligible Inventory (as defined in the revolving credit agreement). As such, the borrowing base can fluctuate based on changes in selling prices of our products and our current material costs, primarily the cost of crude oil. On December 31, 2015, we had availability on our revolving credit facility of $233.5 million, based on a $411.3 million borrowing base, $66.8 million in outstanding standby letters of credit and $111.0 million of outstanding borrowings. The borrowing base cannot exceed the revolving credit facility commitments then in effect. The lender group under our revolving credit facility is comprised of a syndicate of fifteen lenders with total commitments of $1.0 billion. The lenders under our revolving credit facility have a first priority lien on our accounts receivable, inventory and substantially all of our cash.

Amounts outstanding under our revolving credit facility fluctuate materially during each quarter mainly due to cash flow from operations, normal changes in working capital, payments of quarterly distributions to unitholders, capital expenditures and debt service costs. Specifically, the amount borrowed under our revolving credit facility is typically at its highest level after we pay for the majority of our crude oil supply on the 20th day of every month per standard industry terms. The maximum revolving credit facility borrowings during the quarter ended December 31, 2015, were $238.0 million. Our availability on our revolving credit facility during the peak borrowing days of the quarter has been ample to support our operations and service upcoming requirements. During the quarter ended December 31, 2015, availability for additional borrowings under our revolving credit facility was approximately $143.1 million at its lowest point.

The revolving credit facility currently bears interest at a rate equal to prime plus a basis points margin or LIBOR plus a basis points margin, at our option. As of December 31, 2015, this margin was 75 basis points for prime and 175 basis points for LIBOR; however, the margin can fluctuate quarterly based on our average availability for additional borrowings under the revolving credit facility in the preceding calendar quarter.

In addition to paying interest on outstanding borrowings under the revolving credit facility, we are required to pay a commitment fee to the lenders under the revolving credit facility with respect to the unutilized commitments thereunder at a rate equal to either 0.250% or 0.375% per annum depending on the average daily available unused borrowing capacity for the preceding month. We also pay a customary letter of credit fee, including a fronting fee of

0.125% per annum of the stated amount of each outstanding letter of credit, and customary agency fees.

Our revolving credit facility contains various covenants that limit, among other things, our ability to: incur indebtedness; grant liens; dispose of certain assets; make certain acquisitions and investments; redeem or prepay other debt or make other restricted payments such as distributions to unitholders; enter into transactions with affiliates; and enter into a merger, consolidation or sale of assets. The revolving credit facility generally permits us to make cash distributions to our unitholders as long as immediately after giving effect to such a cash distribution we have cash and availability under the revolving credit facility totaling at least the greater of (i) 15% of the Borrowing Base (as defined in the credit agreement) then in effect and (ii) $70.0 million. Further, the revolving credit facility contains one springing financial covenant which provides that only if our availability under the revolving credit facility falls below the greater of (a) 12.5% of the Borrowing Base (as defined in the credit agreement) then in effect and (b) $45.0 million, we will be required to maintain as of the end of each fiscal quarter a Fixed Charge Coverage Ratio (as defined in the credit agreement) of at least 1.0 to 1.0.

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

As of December 31, 2015, we were in compliance with all covenants under the revolving credit facility.

For additional information regarding our revolving credit facility, see Note 7 “Long-Term Debt” in Part II, Item 8 “Financial Statements and Supplementary Data.”

Long-Term Financing

In addition to our principal sources of short-term liquidity listed above, we can meet our cash requirements (other than distributions of Available Cash (as defined in our partnership agreement) to our common unitholders) through the issuance of long-term notes or additional common units.

From time to time we issue long-term debt securities, referred to as our senior notes. All of our outstanding senior notes are unsecured obligations that rank equally with all of our other senior debt obligations to the extent they are unsecured. As of December 31, 2015, we had $900.0 million in 2021 Notes, $350.0 million in 2022 Notes and $325.0 million in 2023 Notes outstanding. As of December 31, 2014, we had $275.0 million in 2020 Notes, $900.0 million in 2021 Notes and $350.0 million in 2022 Notes outstanding. In April 2015, we redeemed all of the $275.0 million aggregate principal amount of 2020 Notes.

The indentures governing our senior notes contain covenants that, among other things, restrict our ability and the ability of certain of our subsidiaries to: (i) sell assets; (ii) pay distributions on, redeem or repurchase our common units or redeem or repurchase its subordinated debt; (iii) make investments; (iv) incur or guarantee additional indebtedness or issue preferred units; (v) create or incur certain liens; (vi) enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us; (vii) consolidate, merge or transfer all or substantially all of our assets; (viii) engage in transactions with affiliates and (ix) create unrestricted subsidiaries. These covenants are subject to important exceptions and qualifications. At any time when the senior notes are rated investment grade by either Moody’s Investors Service, Inc. (“Moody’s”) or Standard & Poor’s Ratings Services (“S&P”) and no Default or Event of Default, each as defined in the indentures governing the senior notes, has occurred and is continuing, many of these covenants will be suspended. As of December 31, 2015, our Fixed Charge Coverage Ratio (as defined in the indentures governing the 2021, 2022 and 2023 Notes) was 1.9 to 1.0.

Upon the occurrence of certain change of control events, each holder of the senior notes will have the right to require that we repurchase all or a portion of such holder’s senior notes in cash at a purchase price equal to 101% of the principal amount thereof, plus any accrued and unpaid interest to the date of repurchase.

To date, our debt balances have not adversely affected our operations, our ability to grow or our ability to repay or refinance our indebtedness. Based on our historical record, we believe that our capital structure will continue to allow us to achieve our business objectives.

We are subject, however, to conditions in the equity and debt markets for our common units and long-term senior notes, and there can be no assurance we will be able or willing to access the public or private markets for our common units and/or senior notes in the future. If we are unable or unwilling to issue additional common units, we may be required to either restrict capital expenditures and/or potential future acquisitions or pursue debt financing alternatives, some of which could involve higher costs or negatively affect our credit ratings. Furthermore, our ability to access the public and private debt markets is affected by our credit ratings.

For additional information regarding our senior notes, see Note 7 “Long-Term Debt” in Part II, Item 8 “Financial Statements and Supplementary Data.”

Master Derivative Contracts and Collateral Trust Agreement

Under our credit support arrangements, our payment obligations under all of our master derivatives contracts for commodity hedging generally are secured by a first priority lien on our and our subsidiaries' real property, plant and equipment, fixtures, intellectual property, certain financial assets, certain investment property, commercial tort claims, chattel paper, documents, instruments and proceeds of the foregoing (including proceeds of hedge arrangements). We had no additional letters of credit or cash margin posted with any hedging counterparty as of December 31, 2015. Our master derivatives contracts and Collateral Trust Agreement (as defined below) continue to impose a number of covenant limitations on our operating and financing activities, including limitations on liens on collateral, limitations on dispositions of collateral and collateral maintenance and insurance requirements. For financial reporting purposes, we do not offset the collateral provided to a counterparty against the fair value of our obligation to that counterparty. Any outstanding collateral is released to us upon settlement of the related derivative instrument liability.

The fair value of our derivatives that were outstanding as of December 31, 2015, decreased by approximately $9.0 million subsequent to December 31, 2015, to a net liability of approximately $38.0 million. All credit support thresholds with our hedging counterparties are at levels such that it would take a substantial increase in fuel products crack spreads or interest rates to require significant additional collateral to be posted. As a result, we do not expect further increases in fuel products crack spreads or interest rates to significantly impact our liquidity.

Additionally, we have a collateral trust agreement (the "Collateral Trust Agreement") which governs how secured hedging counterparties will share collateral pledged as security for the payment obligations owed by us to secured hedging counterparties under their respective master derivatives contracts. The Collateral Trust Agreement limits to $100.0 million the extent to which forward purchase contracts for physical commodities are covered by, and secured under, the Collateral Trust Agreement. There is no such limit on financially settled derivative instruments used for commodity hedging. Subject to certain conditions set forth in the Collateral Trust Agreement, we have the ability to add secured hedging counterparties from time to time.

Equity Transactions

We have entered into an Equity Placement Agreement with various sales agents under which we may issue and sell, from time to time, common units representing limited partner interests, having an aggregate offering price of up to $300.0 million through one or more sales agents. The Equity Placement Agreement provides us the right, but not the obligation, to sell common units in the future, at prices we deem appropriate. These sales, if any, will be made pursuant to the terms of the Equity Placement Agreement between us and the sales agents. The net proceeds from any sales under this agreement will be used for general partnership purposes, which may include, among other things, repayment of indebtedness, working capital, capital expenditures and acquisitions. Our general partner contributed its proportionate capital contribution to retain its 2% general partner interest. For the years ended December 31, 2015 and 2014, we sold 432,167 and 134,955, respectively, common units under the Equity Placement Agreement for net proceeds of $10.2 million and $3.6 million, respectively. Underwriting discounts for 2015 and 2014 totaled $0.1 million and $0.1 million, respectively, and our general partner contributed $0.2 million and $0.1 million, respectively, to maintain its general partner interest.

During 2015, 2014 and 2013, we completed the following marketed public offerings of common units (in millions, except unit and per unit data):

Closing Date	Number of Common Units Offered		Price per Unit	Net Proceeds [1]	General Partner Contribution [2]	Underwriting Discount	Use of Proceeds
January 8, 2013	5,750,000	[3]	$31.81	$175.2	$3.8	$ 7.4	Net proceeds were used to repay borrowings under the revolving credit facility and for general partnership purposes.
April 1, 2013	6,037,500	[4]	$37.50	$217.3	$4.6	$ 9.1	

						Net proceeds were used for general partnership purposes.
March 13, 2015	6,000,000	$26.75	$153.9	$3.3	$ 6.4	Net proceeds were used to redeem a portion of the 2020 Notes and to repay borrowings under the revolving credit facility.

(1) Proceeds are net of underwriting discounts, commissions and expenses but before our general partner's capital contribution.
(2) Our general partner contributions were made to retain its 2% general partner interest.

77

Table of Contents

(3) Includes the full exercise of the overallotment option of 750,000 common units which closed concurrently with the 5,000,000 firm units on January 8, 2013.

(4) Includes the full exercise of the overallotment option of 787,500 common units which closed on April 4, 2013.

During 2015 and through February 2016, we have made the following cash distributions on all outstanding common units (including our general partner's incentive distribution rights) (in millions except per unit data):

Quarter Ended	Declaration Date	Record Date	Distribution Date	Quarterly Distribution per Unit	Aggregate Quarterly Distribution	Annualized Distribution per Unit	Aggregate Annualized Distribution
December 31, 2014	January 23, 2015	February 3, 2015	February 13, 2015	$ 0.685	$ 52.7	$ 2.74	$ 210.8
March 31, 2015	April 20, 2015	May 5, 2015	May 15, 2015	$ 0.685	$ 57.3	$ 2.74	$ 229.2
June 30, 2015	July 21, 2015	August 4, 2015	August 14, 2015	$ 0.685	$ 57.3	$ 2.74	$ 229.2
September 30, 2015	October 22, 2015	November 3, 2015	November 13, 2015	$ 0.685	$ 57.3	$ 2.74	$ 229.2
December 31, 2015	January 19, 2016	February 2, 2016	February 12, 2016	$ 0.685	$ 57.4	$ 2.74	$ 229.6

Seasonality Impacts on Liquidity

The operating results for the fuel products segment, including the selling prices of asphalt products we produce, generally follow seasonal demand trends. Asphalt demand is generally lower in the first and fourth quarters of the year, as compared to the second and third quarters, due to the seasonality of the road construction and roofing industries we supply. Demand for gasoline and diesel is generally higher during the summer months than during the winter months due to seasonal increases in highway traffic. In addition, our natural gas costs can be higher during the winter months, as demand for natural gas as a heating fuel increases during the winter. As a result, our operating results for the first and fourth calendar quarters may be lower than those for the second and third calendar quarters of each year due to seasonality related to these and other products that we produce and sell.

The operating results for the oilfield services segment follow seasonal changes in weather and significant weather events can temporarily affect the performance and delivery of our oilfield services and products. The severity and duration of the winter can have a significant impact on drilling activity. Additionally, customer spending patterns for other oilfield services and products can result in lower activity in the fourth calendar quarter.

Contractual Obligations and Commercial Commitments

A summary of our total contractual cash obligations as of December 31, 2015, at current maturities is as follows:

		Payments Due by Period			
	Total	Less Than 1 Year	1–3 Years	3–5 Years	More Than 5 Years
	(In millions)				
Operating Activities:					
Interest on long-term and short-term debt at contractual rates and maturities (1)	$794.1	$125.0	$244.3	$235.7	$189.1
Operating lease obligations (2)	180.1	42.8	71.3	39.0	27.0
Letters of credit (3)	66.8	66.8	—	—	—
Purchase commitments (4)	811.3	493.6	237.4	80.3	—
Pension obligations	8.5	1.9	1.3	1.6	3.7
Employment agreements	7.0	4.0	2.1	0.9	—
Financing Activities:					
Capital lease obligations	46.4	1.7	3.1	2.2	39.4
Note payable - related party	75.0	75.0	—	—	—
	1,686.0	—	—	111.0	1,575.0

Long-term debt obligations, excluding capital lease obligations					
Total obligations	$3,675.2	$810.8	$559.5	$470.7	$1,834.2

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

(2) We have various operating leases primarily for railcars, the use of land, storage tanks, compressor stations, equipment, precious metals and office facilities that extend through July 2055.

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

(4) Purchase commitments consist primarily of obligations to purchase fixed volumes of crude oil, other feedstocks, finished products for resale and renewable fuels from various suppliers based on current market prices at the time of delivery.

In connection with the closing of the acquisition of Penreco on January 3, 2008, we entered into a feedstock purchase agreement with Phillips 66 related to the LVT unit at its Lake Charles, Louisiana refinery (the "LVT Feedstock Agreement"). Pursuant to the LVT Feedstock Agreement, Phillips 66 is obligated to supply a minimum quantity (the "Base Volume") of feedstock for the LVT unit for a term of ten years. Based upon this minimum supply quantity, we expect to purchase $27.5 million of feedstock for the LVT unit in each fiscal year of the term based on pricing estimates as of December 31, 2015. This amount is not included in the table above.

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

Off-Balance Sheet Arrangements

We did not enter into any material off-balance sheet debt or operating lease transactions during the fiscal year 2015.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements for the years ended December 31, 2015, 2014 and 2013. These consolidated financial statements have been prepared in accordance with GAAP. The preparation of these financial statements requires us to make estimates and judgments that affect the amounts reported in those financial statements. On an ongoing basis, we evaluate estimates and base our estimates on historical experience and assumptions believed to be reasonable under the circumstances. Those estimates form the basis for our judgments that affect the amounts reported in the financial statements. Actual results could differ from our estimates under different assumptions or conditions. Our significant accounting policies, which may be affected by our estimates and assumptions, are more fully described in Note 2 "Summary of Significant Accounting Policies" in Part II, Item 8 "Financial Statements and Supplementary Data." We believe that the following are the more critical judgment areas in the application of our accounting policies that currently affect our financial condition and results of operations.

Revenue Recognition

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

We maintain an allowance for doubtful accounts for estimated losses in the collection of accounts receivable.

Inventory

The cost of inventory is recorded using the LIFO method. Costs include crude oil and other feedstocks, labor, processing costs and refining overhead costs. Inventories are valued at the lower of cost or market. Under the LIFO method, the most recently incurred costs are charged to cost of sales and inventories are valued at the earliest acquisition costs. In periods of rapidly declining prices, LIFO inventories may have to be written down to market value due to the higher costs assigned to LIFO layers in prior periods. Such write downs are subject to reversal in subsequent periods, not to exceed LIFO cost, if prices recover. In addition, the use of the LIFO inventory method may result in increases or decreases to cost of sales in years that inventory volumes decline as the result of charging cost of sales with LIFO inventory costs generated in prior periods. Accordingly, interim LIFO calculations are based on management's estimates of expected year-end inventory levels and are subject to the final year-end LIFO inventory valuation.

Significant Estimates and Assumptions

Judgment is required in determining the market value of inventory, as the geographic location impacts market prices, and quoted market prices may not be available for the particular location of our inventory. Because crude oil and refined products are essentially commodities, we have no control over the changing market value of these inventories. Because our inventory is valued at the lower of cost or market, if the market value of our inventory were to decline to an amount less than our cost, we would record a write-down of inventory and a charge to cost of sales. In a period of decreasing crude oil or refined product prices, our inventory valuation methodology may result in decreases in net income.

Sensitivity Analysis

We have not made any material changes in the accounting methodology we use to establish our markdown or inventory loss adjustments during the past three fiscal years.

The replacement cost of our inventory, based on current market values, would have been $41.0 million lower and $18.9 million lower at December 31, 2015 and 2014, respectively. During the years ended December 31, 2015 and 2014, we recorded $81.8 million and $74.1 million, respectively, of losses in cost of sales in the consolidated statements of operations due to the lower of cost or market inventory valuation. During the years ended December 31, 2015 and 2014, we recorded $24.3 million and $26.5 million, respectively, of losses in cost of sales in the consolidated statements of operations due to the liquidation of higher cost LIFO inventory layers.

Valuation of Definite Long-Lived Assets

Property, plant and equipment and intangible assets with finite lives are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of the asset may not be recoverable. If the estimated undiscounted future cash flows related to the asset are less than the carrying value, we recognize a loss equal to the difference between the carrying value and the estimated fair value, usually determined by the estimated discounted future cash flows of the asset. When a decision has been made to dispose of property and equipment prior to the end of the previously estimated useful life, depreciation estimates are revised to reflect the use of the asset over the shortened estimated useful life.

Significant Estimates and Assumptions

Estimated undiscounted future cash flows are used for the purpose of testing our definite long-lived assets for impairment. Fair values calculated for the purpose of measuring impairments on definite long-lived assets are estimated using the expected present value of future cash flows method and comparative market prices when appropriate. Significant judgment is involved in estimating undiscounted future cash flows and performing these fair value estimates since the results are based on forecasted assumptions. Significant assumptions include:

- Future margins on products produced and sold. Our estimates of future product margins are based on our analysis of various supply and demand factors, which include, among other things, industry-wide capacity, our planned utilization rate, end-user demand, capital expenditures and economic conditions. Such estimates are consistent with those used in our planning and capital investment reviews.
- Future capital requirements. These are based on authorized spending and internal forecasts.
- Discount rate commensurate with the risks involved. We apply a discount rate to our cash flows based on a variety of factors, including market and economic conditions, operational risk, regulatory risk and political risk. This discount rate is also compared to recent observable market transactions, if possible. A higher discount rate decreases the net present value of cash flows.

We base our estimated undiscounted future cash flows and fair value estimates on projected financial information which we believe to be reasonable. However, actual results may differ from these projections.

Sensitivity Analysis

An estimate of the sensitivity to net income resulting from impairment calculations is not practicable, given the numerous assumptions (e.g., pricing, volumes and discount rates) that can materially affect our estimates. That is, unfavorable adjustments to some of the above listed assumptions may be offset by favorable adjustments in other assumptions.

Valuation of Goodwill and Indefinite Lived Intangible Assets

We review goodwill for impairment annually on October 1 and whenever events or changes in circumstances indicate its carrying value may not be recoverable in accordance with ASC 350, Intangibles — Goodwill and Other (Topic 350): Testing Goodwill for Impairment (“ASU 2011-08”). Under ASU 2011-08, an entity has the option to first assess qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not that the fair value of a reporting unit is less than its carrying amount. If, after assessing the totality of events or circumstances, an entity determines it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, then performing the two-step impairment test is unnecessary.

In assessing the qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount, we assess relevant events and circumstances that may impact the fair value and the carrying amount of the reporting unit. The identification of relevant events and circumstances and how these may impact a reporting unit's fair value or carrying amount involve significant judgment and assumptions. The judgment and assumptions include the identification of macroeconomic conditions, industry and market considerations, cost factors, overall financial performance and Company specific events and the assessment on whether each relevant factor will impact the impairment test positively or negatively and the magnitude of any such impact.

If our qualitative assessment concludes that it is probable that an impairment exists or we skip the qualitative assessment, then we need to perform a quantitative assessment. In the first step of the quantitative assessment, our assets and liabilities, including existing goodwill and other intangible assets, are assigned to the identified reporting units to determine the carrying value of the reporting units. If the carrying value of a reporting unit is in excess of its fair value, an impairment may exist, and we must perform an impairment analysis, in which the implied fair value of the goodwill is compared to its carrying value to determine the impairment charge, if any.

When performing the quantitative assessment, 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.

Intangible assets with an indefinite life are not amortized but are subject to review each reporting period to determine whether events and circumstances continue to support an indefinite useful life as well as an annual impairment test.

Due to the continued decline in crude oil prices, we updated our goodwill impairment analysis through September 30, 2015, resulting in the fair value of one reporting unit to be less than its carrying value. The discount rate used in our reporting unit valuation was 15.5%. Revenue growth rates assumed for this reporting unit ranged from (17)% to 18% in 2015 through 2020 and 3% thereafter. A significant decline in our revenue and earnings or a significant decline in the price of common stock could result in an impairment charge in the future. An impairment charge of $33.8 million was recorded on goodwill as a result of this step 2 analysis.

Significant Estimates and Assumptions

Fair values calculated for the purpose of testing our goodwill and indefinite lived intangible assets for impairment is estimated using the expected present value of future cash flows method and comparative market prices when appropriate. Significant judgment is involved in performing these fair value estimates since the results are based on forecasted assumptions. Significant assumptions include:

- Future margins on products produced and sold. Our estimates of future product margins are based on our analysis of various supply and demand factors, which include, among other things, industry-wide capacity, our planned utilization rate, end-user demand, crack spreads, capital expenditures and economic conditions. Such estimates are consistent with those used in our planning and capital investment reviews and include recent historical prices and published forward prices.
- Discount rate commensurate with the risks involved. We apply a discount rate to our cash flows based on a variety of factors, including market and economic conditions, operational risk, regulatory risk and political risk. This discount rate is also compared to recent observable market transactions, if possible. A higher discount rate decreases the net present value of cash flows.
- Future capital requirements. These are based on authorized spending and internal forecasts.

We base our fair value estimates on projected financial information which we believe to be reasonable. However, actual results may differ from these projections.

Sensitivity Analysis

An estimate of the sensitivity to net income resulting from impairment calculations is not practicable, given the numerous assumptions (e.g., pricing, volumes and discount rates) that can materially affect our estimates. That is, unfavorable adjustments to some of the above listed assumptions may be offset by favorable adjustments in other assumptions.

Fair Value of Financial Instruments

As of December 31, 2015, approximately 28% of our recurring liabilities were measured at fair value and classified as Level 3 in the fair value hierarchy. As of December 31, 2015, we had no recurring assets measured at fair value and classified as Level 3 in the fair value hierarchy.

Derivative Instruments

In accordance with ASC 815-10, Derivatives and Hedging, we recognize all derivative instruments as either assets or liabilities at fair value on the consolidated balance sheets. Our derivative instruments are valued at Level 3 fair value measurement under ASC 820-10, Fair Value Measurements and Disclosures, depending upon the degree by which inputs are observable.

The decrease in the fair market value of our outstanding derivative instruments from a net asset of $17.6 million as of December 31, 2014, to a net liability of $33.9 million as of December 31, 2015, was due primarily to increases in the forward market values of fuel products margins, or crack spreads, relative to our hedged products margins and settlements of derivatives in 2015 that resulted in realized gains. We recorded realized gains of $8.1 million and unrealized losses of $39.5 million on derivative instruments for the year ended December 31, 2015.

The increase in the fair market value of our outstanding derivative instruments from a net liability of $54.8 million as of December 31, 2013, to a net asset of $17.6 million as of December 31, 2014, was due primarily to decreases in the forward market values of fuel products margins, or crack spreads, relative to our hedged products margins, partially offset by settlements of derivatives in 2014 that resulted in realized gains. We recorded realized gains of $43.8 million and unrealized losses of $0.6 million on derivative instruments for the year ended December 31, 2014.

Significant Estimates and Assumptions

Our derivative instruments consist of over-the-counter contracts, which are not traded on a public exchange. Substantially all of our derivative instruments are with counterparties that have long-term credit ratings of at least Baa1 and BBB+ by Moody’s and S&P, respectively.

To estimate the fair values of our derivative instruments, we use the forward rate, the strike price, contractual notional amounts, the risk free rate of return and contract maturity. Various analytical tests are performed to validate the counterparty data. The fair values of our derivative instruments are adjusted for nonperformance risk and creditworthiness of the hedging entities through our credit valuation adjustment (“CVA”). The CVA is calculated at the transaction level utilizing the fair value exposure at each payment date and applying a weighted probability of the appropriate survival and marginal default percentages. We use the counterparty’s marginal default rate and our survival rate when we are in a net asset position at the payment date and use our marginal default rate and the counterparty’s survival rate when we are in a net liability position at the payment date. As a result of applying the applicable CVA at December 31, 2015, our net liability was reduced by approximately $1.2 million. As a result of applying the CVA at December 31, 2014, our net asset was increased by approximately $2.0 million and net liability was reduced by approximately $0.1 million.

Observable inputs utilized to estimate the fair values of our derivative instruments were primarily based on inputs that are readily available in public markets or can be derived from information available in publicly quoted markets. Based on the use of various unobservable inputs, principally non-performance risk, creditworthiness of the hedging entities and unobservable inputs in the forward rate, we have 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. We believe we have obtained the most accurate information available for the types of derivative instruments we hold. See Note 8 “Derivatives” in Part II, Item 8 “Financial Statements and Supplementary Data” for further information on derivative instruments.

Sensitivity Analysis

We have not made any material changes in the accounting methodology we use to establish our derivative values or pension asset valuations during the past three fiscal years. We have consistently applied these valuation techniques in all periods presented and believe we obtained the most accurate information available for the types of derivative instruments and pension assets we hold.

We believe that the fair values of our derivative instruments may diverge materially from the amounts currently recorded at fair value at settlement due to the volatility of commodity prices. Holding all other variables constant, we expect a $1.00 increase in the applicable commodity prices would change our recorded mark-to-market valuation by the following amounts based upon the volumes hedged as of December 31, 2015:

	In millions
Crude oil swaps	$0.7
Crude oil basis swaps	$1.5
Crude oil percentage basis swaps	$3.7
Crude oil options	$0.4
Gasoline crack spread swaps	$(0.9)
Natural gas swaps	$13.4
Natural gas collars	$0.6

Recent Accounting Pronouncements

For a summary of recently issued and adopted accounting standards applicable to us, see Note 2 "Summary of Significant Accounting Policies" in Part II, Item 8 "Financial Statements and Supplementary Data."

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

Derivative Instruments

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

- crude oil purchases and sales;
- refined product sales and purchases;
- natural gas purchases;
- precious metals; and
- fluctuations in the value of crude oil between geographic regions and between the different types of crude oil such as NYMEX WTI, Light Louisiana Sweet ("LLS"), Western Canadian Select ("WCS"), Mixed Sweet Blend ("MSW") and ICE Brent ("Brent").

We manage our exposure to commodity markets, credit, volumetric and liquidity risks to manage our costs and volatility of cash flows as conditions warrant or opportunities become available. These risks may be managed in a variety of ways that may include the use of derivative instruments. Derivative instruments may be used for the purpose of mitigating risks associated with an asset, liability and anticipated future transactions and the changes in fair value of our derivative instruments will affect our earnings and cash flows; however, such changes should be offset by price or rate changes related to the underlying commodity or financial transaction that is part of the risk management strategy. We do not speculate with derivative instruments or other contractual arrangements that are not associated with our business objectives. Speculation is defined as increasing our natural position above the maximum position of our physical assets or trading in commodities, currencies or other risk bearing assets that are not associated with our business activities and objectives. Our positions are monitored routinely by a risk management committee and discussed with our board of directors quarterly to ensure compliance with our stated risk management policy and documented risk management strategies. All strategies are reviewed on an ongoing basis by our risk management committee, which will add, remove or revise strategies in anticipation of changes in market conditions and/or in risk profiles. These changes in strategies are to position us in relation to our risk exposures in an attempt to capture market opportunities as they arise.

The following table provides a summary of the implied crack spreads for our gasoline crack spread swaps as of December 31, 2015, in our fuel products segment:

Gasoline Crack Spread Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
First Quarter 2016	873,000	9,593	$8.98
Total	873,000		
Average price			$8.98

79

Table of Contents

The following table provides a summary of crude oil swaps as of December 31, 2015, in our fuel products segment:

Crude Oil Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Swap ($/Bbl)
First Quarter 2016	29,120	320	$44.06
Second Quarter 2016	29,120	320	$44.06
Third Quarter 2016	29,440	320	$44.06
Fourth Quarter 2016	29,440	320	$44.06
Calendar Year 2017	630,720	1,728	$54.94
Total	747,840		
Average price			$53.24

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

Crude Oil Percentage Basis Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Fixed Percentage of NYMEX WTI (Average % of WTI/Bbl)	
First Quarter 2016	728,000	8,000	73.5	%
Second Quarter 2016	728,000	8,000	73.5	%
Third Quarter 2016	736,000	8,000	73.5	%
Fourth Quarter 2016	736,000	8,000	73.5	%
Calendar Year 2017	730,000	2,000	73.0	%
Total	3,658,000			
Average percentage			73.4	%

We entered into derivative instruments to mitigate the risk of future changes in the price of NYMEX WTI crude oil. The following table provides a summary of crude oil call option purchases as of December 31, 2015, in our fuel products segment:

Crude Oil Option Contracts by Expiration Dates	Barrels Purchased	BPD	Average Bought Call ($/Bbl)
Fourth Quarter 2016	350,000	11,290	$55.00
Total	350,000		
Average price			$55.00

We entered into derivative instruments to mitigate the risk of future changes in pricing differentials between LLS and NYMEX WTI. The following table provides a summary of crude oil basis swap contracts as of December 31, 2015, in our fuel products segment:

Crude Oil Basis Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Differential to NYMEX WTI ($/Bbl)
First Quarter 2016	182,000	2,000	$2.40
Second Quarter 2016	182,000	2,000	$2.40
Third Quarter 2016	184,000	2,000	$2.40
Fourth Quarter 2016	184,000	2,000	$2.40
Total	732,000		
Average differential			$2.40

Table of Contents

We entered into crude oil basis swaps to mitigate the risk of future changes in pricing differentials between WCS and NYMEX WTI. The following table provides a summary of crude oil basis swap contracts as of December 31, 2015, in our fuel products segment:

Crude Oil Basis Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Differential to NYMEX WTI ($/Bbl)
First Quarter 2016	91,000	1,000	$(14.10)
Second Quarter 2016	91,000	1,000	$(14.10)
Third Quarter 2016	92,000	1,000	$(14.10)
Fourth Quarter 2016	92,000	1,000	$(14.10)
Calendar Year 2017	365,000	1,000	$(13.70)
Total	731,000		
Average differential			$(13.90)

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

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

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

Natural Gas Swap Contracts by Expiration Dates	MMBtu	$/MMBtu
First Quarter 2016	1,580,000	$4.24
Second Quarter 2016	1,380,000	$4.26
Third Quarter 2016	1,380,000	$4.26
Fourth Quarter 2016	1,540,000	$4.14
Calendar Year 2017	4,950,000	$3.85
Total	10,830,000	
Average price		$4.05

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

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

Please read Note 8 “Derivatives” in the notes to our consolidated financial statements under Part II, Item 8 “Financial Statements and Supplementary Data” for a discussion of the accounting treatment for the various types of derivative instruments, for a further discussion of our hedging policies and for more information relating to our implied crack spreads of crude oil, diesel, gasoline and jet fuel derivative instruments.

Table of Contents

Our derivative instruments and overall specialty products segment and fuel products segment hedging positions are monitored regularly by our risk management committee, which includes executive officers. The risk management committee reviews market information and our hedging positions regularly to determine if additional derivatives activity is advised. A summary of derivative positions and a summary of hedging strategy are presented to our general partner's board of directors quarterly.

The following table illustrates how a change in market price (holding all other variables constant and excluding the impact of our current hedges) would affect our sales and cost of sales in the consolidated statements of operations:

	Sales		Cost of Sales	
	Year Ended December 31,		Year Ended December 31,	
	2015	2014	2015	2014
	(In millions)			
Specialty Products:				
$1.00 change in per barrel price of crude oil [1]			$9.2	$9.1
$0.50 change in MMBtu (one million British Thermal Units) of natural gas [2]			$6.0	$6.0
Fuel Products:				
$1.00 change in per barrel price of crude oil [1]			$28.2	$25.7
$1.00 change in per barrel selling price of gasoline, diesel and jet fuel [1]	$28.2	$25.7		

(1) Based on our 2015 and 2014 sales volumes.

(2) Based on our results for the years ended December 31, 2015 and 2014.

Revolving Credit Facility

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. Our inventory is based on local crude oil prices at period end, which can materially fluctuate period to period.

Pension Assets Volatility and Investment Policy

Our Pension Plan assets are also subject to volatility that can be caused by fluctuation in general economic conditions. Plan assets are invested by the Plan's fiduciaries, which direct investments according to specific policies. Our consolidated statement of operations is currently shielded from volatility in plan assets due to the way accounting standards are applied for pension plans, although favorable or unfavorable investment performance over the long term will impact our pension expense if it deviates from our assumption related to the future rate of return. Please read Note 12 "Employee Benefit Plans" under Part II, Item 8 "Financial Statements and Supplementary Data" for a further discussion of our investment policies.

Compliance Price Risk

Renewable Identification Numbers

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

Holding other variables constant (RINs requirements), a $1.00 change in the price of RINs as of December 31, 2015, would be expected to have an impact on net income for 2015 of approximately $125.4 million.

Interest Rate Risk

We use various strategies to reduce our exposure to interest rate risk, including the use of financially settled derivative instruments, such as interest rate swaps and options, to minimize significant unplanned fluctuations in earnings that are caused by interest rate volatility. Our goal is to manage interest rate sensitivity by modifying the pricing characteristics of certain debt instruments so that earnings are not adversely affected by movement in interest rates. During 2014, we entered into an interest rate swap agreement that converted a portion of our senior notes from a fixed interest rate to a variable rate that fluctuates based on changes in the one-month London Interbank Offered Rate (“LIBOR”). During the first quarter 2015, we terminated this interest rate swap agreement. We have disclosed this interest rate swap designated as a fair value hedge in Note 8 “Derivatives” under Part II, Item 8 “Financial Statements and Supplementary Data.”

Our exposure to interest rate changes is limited to the fair value of the debt issued, which would not have a material impact on our earnings or cash flows. The following table provides information about the fair value of our fixed rate debt obligations as of December 31, 2015 and 2014, which we disclose in Note 7 “Long-Term Debt” and Note 9 “Fair Value Measurements” under Part II, Item 8 “Financial Statements and Supplementary Data.”

	December 31, 2015		December 31, 2014	
	Fair Value	Carrying Value	Fair Value	Carrying Value
	(In millions)			
Financial Instrument:				
2020 Notes	$—	$—	$290.5	$265.4
2021 Notes	$798.3	$888.0	$803.3	$885.3
2022 Notes	$297.5	$342.8	$339.5	$341.2
2023 Notes	$294.1	$317.6	$—	$—

For our variable rate debt, if any, changes in interest rates generally do not impact the fair value of the debt instrument, but may impact our future earnings and cash flows. We had a $1.0 billion revolving credit facility as of December 31, 2015, with borrowings bearing interest at the prime rate or LIBOR, at our option, plus the applicable margin. Borrowings under this facility are variable. We had $111.0 million of variable rate debt as of December 31, 2015. Holding other variables constant (such as debt levels), a 100 basis point change in interest rates on our variable rate debt as of December 31, 2015, would be expected to have an impact on net income and cash flows for 2015 of approximately $1.1 million. We had $150.8 million of variable rate debt outstanding as of December 31, 2014.

Foreign Currency Risk

We have minimal exposure to foreign currency risk and as such the cost of hedging this risk is viewed to be in excess of the benefit of further reductions in our exposure to foreign currency exchange rate fluctuations.

Table of Contents

Item 8. Financial Statements and Supplementary Data

Management's Report on Internal Control Over Financial Reporting

The management of Calumet Specialty Products Partners, L.P. (the "Company") is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles. Internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of the financial statements in accordance with U.S. generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies and procedures may deteriorate.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2015, based on criteria for effective internal control over financial reporting described in "Internal Control — Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) ("COSO"). Based on this assessment, we have concluded that internal control over financial reporting was effective as of December 31, 2015.

Ernst & Young LLP, an independent registered public accounting firm, has audited the Company's consolidated financial statements and has issued an attestation report on the effectiveness of internal control over financial reporting which appears on the following page.

February 29, 2016	/s/ Timothy Go Timothy Go Chief Executive Officer of Calumet GP, LLC, general partner of Calumet Specialty Products Partners, L.P. (Principal Executive Officer)
February 29, 2016	/s/ R. Patrick Murray, II R. Patrick Murray, II Executive Vice President, Chief Financial Officer and Secretary of Calumet GP, LLC (Principal Accounting and Financial Officer)

Table of Contents

Report of Independent Registered Public Accounting Firm

The Board of Directors of Calumet GP, LLC
General Partner of Calumet Specialty Products Partners, L.P.

We have audited Calumet Specialty Products Partners, L.P.'s internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). Calumet Specialty Products Partners, L.P.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion Calumet Specialty Products Partners, L.P. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Calumet Specialty Products Partners, L.P. as of December 31, 2015 and 2014, and the related consolidated statements of operations and comprehensive income (loss), partners' capital and cash flows for each of the three years in the period ended December 31, 2015, of Calumet Specialty Products Partners, L.P. and our report dated February 29, 2016, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Indianapolis, Indiana
February 29, 2016

Table of Contents

Report of Independent Registered Public Accounting Firm

The Board of Directors of Calumet GP, LLC
General Partner of Calumet Specialty Products Partners, L.P.

We have audited the accompanying consolidated balance sheets of Calumet Specialty Products Partners, L.P. as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income (loss), partners' capital and cash flows for each of the three years in the period ended December 31, 2015. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We did not audit the financial statements of Dakota Prairie Refining, LLC a company in which Calumet Specialty Products Partners, L.P. has a 50% interest. In the consolidated financial statements, Calumet Specialty Products Partners, L.P's investment in Dakota Prairie Refining, LLC is stated at $124.7 million as of December 31, 2015 and Calumet Specialty Products Partners, L.P.'s equity in the net loss of Dakota Prairie Refining, LLC is stated at $36.1 million for the year ended December 31, 2015. Those statements were audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to the 2015 amounts included for Dakota Prairie Refining, LLC, is based solely on the report of the other auditors.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits and the report of other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the report of other auditors, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Calumet Specialty Products Partners, L.P. at December 31, 2015 and 2014, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Calumet Specialty Products Partners, L.P.'s internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 29, 2016, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Indianapolis, Indiana
February 29, 2016

Table of Contents

CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
CONSOLIDATED BALANCE SHEETS

	Year Ended December 31,	
	2015	2014
	(In millions, except unit data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$5.6	$8.5
Accounts receivable:		
Trade, less allowance for doubtful accounts of $2.0 million and $1.6 million, respectively	195.3	326.0
Other	15.4	23.8
	210.7	349.8
Inventories	384.4	513.5
Derivative assets	—	23.2
Prepaid expenses and other current assets	8.3	9.2
Total current assets	609.0	904.2
Property, plant and equipment, net	1,719.2	1,464.4
Investment in unconsolidated affiliates	126.0	137.3
Goodwill	212.0	245.8
Other intangible assets, net	214.1	257.5
Noncurrent deferred income taxes	—	2.3
Other noncurrent assets, net	64.4	73.6
Total assets	$2,944.7	$3,085.1
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$316.6	$419.9
Accrued interest payable	31.1	37.6
Accrued salaries, wages and benefits	32.9	21.9
Other taxes payable	17.9	17.9
Other current liabilities	119.0	40.0
Current portion of long-term debt	1.7	0.6
Note payable - related party	73.5	—
Derivative liabilities	33.9	5.6
Total current liabilities	626.6	543.5
Noncurrent deferred income taxes	2.1	32.3
Pension and postretirement benefit obligations	13.0	20.0
Other long-term liabilities	0.9	0.9
Long-term debt, less current portion	1,698.2	1,678.2
Total liabilities	2,340.8	2,274.9
Commitments and contingencies		
Partners' capital:		
Limited partners' interest (75,884,400 units and 69,452,233 units, issued and outstanding at December 31, 2015 and 2014, respectively)	578.0	765.9
General partner's interest	27.5	30.6
Accumulated other comprehensive income (loss)	(1.6)	13.7
Total partners' capital	603.9	810.2
Total liabilities and partners' capital	$2,944.7	$3,085.1

See accompanying notes to consolidated financial statements.

Table of Contents

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

	Year Ended December 31,		
	2015	2014	2013
	(In millions, except unit and per unit data)		
Sales	$4,212.8	$5,791.1	$5,421.4
Cost of sales	3,618.2	5,261.4	5,011.4
Gross profit	594.6	529.7	410.0
Operating costs and expenses:			
Selling	146.0	149.6	62.6
General and administrative	135.5	98.3	82.1
Transportation	175.5	171.4	142.7
Taxes other than income taxes	17.7	13.4	14.2
Asset impairment	33.8	36.0	10.5
Other	11.1	14.2	6.3
Operating income	75.0	46.8	91.6
Other income (expense):			
Interest expense	(104.9)	(110.8)	(96.8)
Debt extinguishment costs	(46.6)	(89.9)	(14.6)
Realized gain (loss) on derivative instruments	8.1	43.8	(4.7)
Unrealized gain (loss) on derivative instruments	(39.5)	(0.6)	25.7
Loss from unconsolidated affiliates	(61.5)	(3.4)	(0.3)
Other	1.6	1.1	3.0
Total other expense	(242.8)	(159.8)	(87.7)
Net income (loss) before income taxes	(167.8)	(113.0)	3.9
Income tax expense (benefit)	(28.4)	(0.8)	0.4
Net income (loss)	$(139.4)	$(112.2)	$3.5
Allocation of net income (loss):			
Net income (loss)	$(139.4)	$(112.2)	$3.5
Less:			
General partner’s interest in net income (loss)	(2.8)	(2.2)	0.1
General partner’s incentive distribution rights	16.8	15.4	14.7
Non-vested share based payments	—	—	0.2
Net loss available to limited partners	$(153.4)	$(125.4)	$(11.5)
Weighted average limited partner units outstanding:			
Basic	74,896,096	69,671,827	67,938,784
Diluted	74,896,096	69,671,827	67,938,784
Limited partners’ interest basic and diluted net loss per unit	$(2.05)	$(1.80)	$(0.17)
Cash distributions declared per limited partner unit	$2.74	$2.74	$2.70

See accompanying notes to consolidated financial statements.

Table of Contents

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

	Year Ended December 31,		
	2015	2014	2013
	(In millions)		
Net income (loss)	$(139.4)	$(112.2)	$3.5
Other comprehensive income (loss):			
Cash flow hedges:			
Cash flow hedge gain reclassified to net income (loss)	(12.1)	(37.0)	(0.5)
Change in fair value of cash flow hedges	(7.3)	114.2	(36.9)
Defined benefit pension and retiree health benefit plans	4.7	(9.6)	9.6
Foreign currency translation adjustment	(0.6)	(0.5)	(0.1)
Total other comprehensive income (loss)	(15.3)	67.1	(27.9)
Comprehensive loss attributable to partners’ capital	$(154.7)	$(45.1)	$(24.4)

See accompanying notes to consolidated financial statements.

Table of Contents

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

	Accumulated Other Comprehensive Income (Loss)	Partners' Capital		
		General Partner	Limited Partners	Total
	(In millions)			
Balance at December 31, 2012	$(25.5)	$30.5	$884.8	$889.8
Other comprehensive loss	(27.9)	—	—	(27.9)
Net income (loss)	—	14.8	(11.3)	3.5
Common units repurchased for phantom unit grants	—	—	(5.0)	(5.0)
Issuance of phantom units, net of taxes withheld	—	—	(0.3)	(0.3)
Amortization of vested phantom units	—	—	3.2	3.2
Proceeds from public offerings of common units, net	—	—	392.5	392.5
Contributions from Calumet GP, LLC	—	8.4	—	8.4
Distributions to partners	—	(17.1)	(184.3)	(201.4)
Balance at December 31, 2013	$(53.4)	$36.6	$1,079.6	$1,062.8
Other comprehensive income	67.1	—	—	67.1
Net income (loss)	—	13.2	(125.4)	(112.2)
Common units repurchased for phantom unit grants	—	—	(2.2)	(2.2)
Issuance of phantom units, net of taxes withheld	—	—	(1.2)	(1.2)
Cash settlement of unit based compensation	—	—	(0.9)	(0.9)
Amortization of vested phantom units	—	—	3.0	3.0
Proceeds from public offerings of common units, net	—	—	3.6	3.6
Contributions from Calumet GP, LLC	—	0.1	—	0.1
Distributions to partners	—	(19.3)	(190.6)	(209.9)
Balance at December 31, 2014	$13.7	$30.6	$765.9	$810.2
Other comprehensive loss	(15.3)	—	—	(15.3)
Net income (loss)	—	14.0	(153.4)	(139.4)
Common units repurchased for phantom unit grants	—	—	(3.6)	(3.6)
Issuance of phantom units, net of taxes withheld	—	—	(1.5)	(1.5)
Reclassification of Liability Awards to equity	—	—	7.9	7.9
Amortization of vested phantom units	—	—	2.4	2.4
Proceeds from public offerings of common units, net	—	—	164.1	164.1
Contributions from Calumet GP, LLC	—	3.5	—	3.5
Distributions to partners	—	(20.6)	(203.8)	(224.4)
Balance at December 31, 2015	$(1.6)	$27.5	$578.0	$603.9

See accompanying notes to consolidated financial statements.

Table of Contents

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

	Year Ended December 31,		
	2015	2014	2013
	(In millions)		
Operating activities			
Net income (loss)	$(139.4)	$(112.2)	$3.5
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	145.4	138.6	117.8
Amortization of turnaround costs	29.0	24.5	15.9
Non-cash interest expense	6.6	6.4	7.0
Non-cash debt extinguishment costs	9.1	19.0	3.4
Provision for doubtful accounts	1.1	0.5	0.1
Unrealized (gain) loss on derivative instruments	39.5	0.6	(25.7)
Asset impairment	33.8	36.0	10.5
Loss on disposal of fixed assets	2.9	4.8	15.2
Non-cash equity based compensation	9.8	6.5	4.8
Deferred income tax benefit	(28.5)	(1.2)	—
Lower of cost or market inventory adjustment	81.8	74.1	(2.1)
Loss from unconsolidated affiliates	61.5	3.4	0.3
Other non-cash activities	5.9	0.7	(10.2)
Changes in assets and liabilities:			
Accounts receivable	138.0	(0.4)	(32.3)
Inventories	47.3	43.9	16.4
Prepaid expenses and other current assets	3.4	3.9	6.8
Derivative activity	(7.0)	6.7	(1.8)
Turnaround costs	(19.3)	(27.6)	(68.6)
Other assets	—	—	(0.1)
Accounts payable	(119.9)	(13.1)	6.8
Accrued interest payable	(6.5)	15.1	(1.0)
Accrued salaries, wages and benefits	10.2	(14.7)	(7.1)
Accrued income taxes payable	—	—	(27.6)
Other taxes payable	0.2	(1.1)	3.0
Other liabilities	73.8	13.7	6.8
Pension and postretirement benefit obligations	(2.3)	(1.3)	(2.7)
Net cash provided by operating activities	376.4	226.8	39.1
Investing activities			
Additions to property, plant and equipment	(339.3)	(289.9)	(160.8)
Investment in unconsolidated affiliates	(58.6)	(105.4)	(31.8)
Cash paid for acquisitions, net of cash acquired	—	(263.6)	(177.7)
Return of investment from unconsolidated affiliate	8.4	—	—
Proceeds from sale of property, plant and equipment	0.5	0.1	—
Net cash used in investing activities	(389.0)	(658.8)	(370.3)
Financing activities			
Proceeds from borrowings — revolving credit facility	1,390.0	1,625.1	865.6
Repayments of borrowings — revolving credit facility	(1,429.8)	(1,474.3)	(865.6)

Repayments of borrowings — senior notes	(275.0)	(500.0)	(100.0)
Repayments of borrowings — acquisition debt assumed	—	—	(11.9)
Proceeds from borrowings — related party	75.0	—	—
Payments on capital lease obligations	(8.0)	(1.9)	(1.1)
Proceeds from other financing obligations	1.1	—	3.5
Proceeds from public offerings of common units, net	164.1	3.6	392.5
Proceeds from senior notes offerings	322.6	900.0	344.7
Debt issuance costs	(5.6)	(19.9)	(7.3)
Contributions from Calumet GP, LLC	3.5	0.1	8.4
Common units repurchased and taxes paid for phantom unit grants	(3.6)	(2.2)	(7.1)
Cash settlement of unit based compensation	—	(0.9)	—
Distributions to partners	(224.6)	(210.2)	(201.6)
Net cash provided by financing activities	9.7	319.4	420.1
Net increase (decrease) in cash and cash equivalents	(2.9)	(112.6)	88.9
Cash and cash equivalents at beginning of year	8.5	121.1	32.2
Cash and cash equivalents at end of year	$5.6	$8.5	$121.1
Supplemental disclosure of cash flow information			
Interest paid, net of capitalized interest	$120.6	$107.8	$91.4
Income taxes paid	$1.1	$0.5	$29.8
Supplemental disclosure of non-cash investing and financing activities			
Non-cash property, plant and equipment additions	$56.5	$39.9	$13.1
Non-cash capital lease	$4.4	$39.4	$—

See accompanying notes to consolidated financial statements.

Table of Contents

CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Description of the Business

Calumet Specialty Products Partners, L.P. (the "Company") is a publicly traded Delaware limited partnership listed on the NASDAQ Global Select Market ("NASDAQ") under the ticker symbol "CLMT." The general partner of the Company is Calumet GP, LLC, a Delaware limited liability company. As of December 31, 2015, the Company had 75,884,400 limited partner common units and 1,548,660 general partner equivalent units outstanding. The general partner owns 2% of the Company and all of the incentive distribution rights (as defined in the Company's partnership agreement), while the remaining 98% is owned by limited partners. The general partner employs all of the Company's employees and the Company reimburses the general partner for certain of its expenses.

The Company is engaged in the production and marketing of crude oil-based specialty products including lubricating oils, white mineral oils, solvents, petrolatums, waxes, and fuel and fuel related products including gasoline, diesel, jet fuel, asphalt and heavy fuel oils, in addition to oilfield services and products. The Company is based in Indianapolis, Indiana and owns specialty and fuel products facilities. The Company owns and leases oilfield services locations and leases additional facilities, primarily related to production and distribution of specialty, fuel and oilfield services products, throughout the United States ("U.S.").

2. Summary of Significant Accounting Policies

Consolidation

The consolidated financial statements reflect the accounts of the Company and its wholly-owned and majority-owned subsidiaries. All intercompany profits, transactions and balances have been eliminated.

Reclassifications

Certain amounts in the prior years' consolidated financial statements have been reclassified to conform to the current year presentation.

Use of Estimates

The Company's consolidated financial statements are prepared in conformity with U.S. generally accepted accounting principles ("U.S. GAAP") which require management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Cash and Cash Equivalents

Cash and cash equivalents include all highly liquid investments with a maturity of three months or less at the time of purchase.

Accounts Receivable

The Company performs periodic credit evaluations of customers' financial condition and generally does not require collateral. Accounts receivable are carried at their face amounts. The Company maintains an allowance for doubtful accounts for estimated losses in the collection of accounts receivable. The Company makes estimates regarding the future ability of its customers to make required payments based on historical experience, the age of the accounts receivable balances, credit quality of the Company's customers, current economic conditions, expected future trends and other factors that may affect customers' ability to pay. Individual accounts are written off against the allowance for doubtful accounts after all reasonable collection efforts have been exhausted.

The activity in the allowance for doubtful accounts was as follows (in millions):

	December 31,		
	2015	2014	2013
Beginning balance	$1.6	$1.2	$1.2
Provision	1.1	0.5	0.1
Write-offs, net	(0.7)	(0.1)	(0.1)
Ending balance	$2.0	$1.6	$1.2

Inventories

The cost of inventory is recorded using the last-in, first-out (“LIFO”) method. Costs include crude oil and other feedstocks, labor, processing costs and refining overhead costs. Inventories are valued at the lower of cost or market value. The replacement cost of these inventories, based on current market values, would have been $41.0 million lower and $18.9 million lower as of

December 31, 2015 and 2014, respectively. At December 31, 2015 and 2014, the Company had $1.4 million and $1.7 million, respectively, of consigned inventory.

Inventories consisted of the following (in millions):

	December 31,	
	2015	2014
Raw materials	$47.9	$77.8
Work in process	64.0	75.4
Finished goods	272.5	360.3
	$384.4	$513.5

Under the LIFO method, the most recently incurred costs are charged to cost of sales and inventories are valued at the earliest acquisition costs. For each of the years ended December 31, 2015, 2014 and 2013, the Company recorded gains and (losses) of $(24.3) million, $(26.5) million and $4.2 million, respectively, in cost of sales in the consolidated statements of operations due to the liquidation of inventory layers.

In addition, the use of the LIFO inventory method may result in increases or decreases to cost of sales in years that inventory volumes decline as the result of charging cost of sales with LIFO inventory costs generated in prior periods. In periods of rapidly declining prices, LIFO inventories may have to be written down to market value due to the higher costs assigned to LIFO layers in prior periods. Such write downs are subject to reversal in subsequent periods, not to exceed LIFO cost, if prices recover. During the years ended December 31, 2015 and 2014 the Company recorded $81.8 million and $74.1 million, respectively, of losses in cost of sales in the consolidated statements of operations due to the lower of cost or market valuation. During the year ended December 31, 2013, the Company recorded $2.1 million of gains in cost of sales in the consolidated statements of operations due to the lower of cost or market valuation.

Derivatives

The Company is exposed to fluctuations in the price of numerous commodities, such as crude oil (its principal raw material) and natural gas, as well as the sales prices of gasoline, diesel and jet fuel. Given the historical volatility of commodity prices, these fluctuations can significantly impact sales, gross profit and net income. Therefore, the Company utilizes derivative instruments primarily to minimize its price risk and volatility of cash flows associated with the purchase of crude oil and natural gas and the sale of fuel products. The Company employs various hedging strategies and does not hold or issue derivative instruments for trading purposes. For further information, please refer to Note 8.

Property, Plant and Equipment

Property, plant and equipment are stated on the basis of cost. Depreciation is calculated generally on composite groups, using the straight-line method over the estimated useful lives of the respective groups. Assets under capital leases are amortized over the lesser of the useful life of the asset or the term of the lease.

Property, plant and equipment, including depreciable lives, consisted of the following (in millions):

	December 31,	
	2015	2014
Land	$19.5	$18.3
Buildings and improvements (10 to 40 years)	70.2	66.8
Machinery and equipment (10 to 20 years)	1,629.7	1,420.7
Furniture and fixtures (5 to 10 years)	28.5	21.8
Assets under capital leases (4 to 26 years)	49.0	48.9
Construction-in-progress	466.4	354.0
	2,263.3	1,930.5
Less accumulated depreciation	(544.1)	(466.1)

	$1,719.2	$1,464.4

Under the composite depreciation method, the cost of partial retirements of a group is charged to accumulated depreciation. However, when there are dispositions of complete groups or significant portions of groups, the cost and related accumulated depreciation are retired, and any gain or loss is reflected in earnings.

During 2015, 2014 and 2013, the Company incurred $133.5 million, $122.8 million and $101.2 million, respectively, of interest expense of which $28.6 million, $12.0 million and $4.4 million, respectively, was capitalized as a component of property, plant and equipment.

The Company has not recorded an asset retirement obligation as of December 31, 2015 or 2014 because such potential obligations cannot be measured since it is not possible to estimate the settlement dates.

During the years ended December 31, 2015, 2014 and 2013, the Company recorded $102.0 million, $98.3 million and $92.0 million, respectively, of depreciation expense on its property, plant and equipment. Depreciation expense included $2.6 million, $0.8 million and $0.7 million for the years ended 2015, 2014 and 2013, respectively, related to the Company’s capital lease assets.

The Company capitalizes the cost of computer software developed or obtained for internal use. Capitalized software is amortized using the straight-line method over five years. As of December 31, 2015 and 2014, the Company had $17.4 million and $17.4 million, respectively, of capitalized software costs. As of December 31, 2015 and 2014, the Company had $13.1 million and $8.9 million, respectively of accumulated depreciation related to the capitalized software costs. During the years ended December 31, 2015, 2014 and 2013, the Company recorded $4.2 million, $3.4 million, and $3.3 million, respectively, of amortization expense on capitalized computer software. Capitalized software is included in furniture and fixtures.

Investment in Unconsolidated Affiliates

The Company accounts for its ownership in its Dakota Prairie Refining, LLC and Juniper GTL LLC joint ventures in accordance with ASC 323, Investments — Equity Method and Joint Ventures. The equity method of accounting is applied when the investor has an ownership interest of less than 50% and/or has significant influence over the operating or financial decisions of the investee. Under the equity method, the Company’s proportionate share of net income (loss) is reflected as a single-line item in the consolidated statements of operations and as increases or decreases, as applicable, in the carrying value of the Company’s investment in the consolidated balance sheets. In addition, the proportionate share of net income (loss) is reflected as a non-cash activity in operating activities in the consolidated statements of cash flows. Contributions increase the carrying value of the investment and are reflected as an investing activity in the consolidated statements of cash flows.

Equity method investments are assessed for other-than-temporary impairment when the investment generates net losses. The Company recorded a $24.3 million impairment charge in loss from unconsolidated affiliates in the consolidated statement of operations for the year ended December 31, 2015. No impairment was recognized in 2014 and 2013. For further information on investment in unconsolidated affiliates, refer to Note 4.

Goodwill and Indefinite Lived Intangible Assets

Goodwill represents the excess of purchase price over fair value of the net assets acquired in various acquisitions. See Note 3 for more information. The Company reviews goodwill for impairment annually on October 1 and whenever events or changes in circumstances indicate its carrying value may not be recoverable in accordance with ASC 350, Intangibles — Goodwill and Other (Topic 350): Testing Goodwill for Impairment (“ASU 2011-08”). Under ASU 2011-08, an entity has the option to first assess qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not that the fair value of a reporting unit is less than its carrying amount. If, after assessing the totality of events or circumstances, an entity determines it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, then performing the two-step impairment test is unnecessary.

In assessing the qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount, the Company assesses relevant events and circumstances that may impact the fair value and the carrying amount of the reporting unit. The identification of relevant events and circumstances and how these may impact a reporting unit’s fair value or carrying amount involve significant judgment and assumptions. The judgment and assumptions include the identification of macroeconomic conditions, industry and market considerations, cost factors, overall financial performance and Company specific events and making the assessment on whether each relevant factor will impact the impairment test positively or negatively and the magnitude of any such impact.

If the Company's qualitative assessment concludes that it is probable that an impairment exists or the Company skips the qualitative assessment then the Company needs to perform a quantitative assessment. In the first step of the quantitative assessment, the Company's assets and liabilities, including existing goodwill and other intangible assets, are assigned to the identified reporting units to determine the carrying value of the reporting units. If the carrying value of a reporting unit is in excess of its fair value, an impairment may exist, and the Company must perform an impairment analysis, in which the implied fair value of the goodwill is compared to its carrying value to determine the impairment charge, if any.

When performing the quantitative assessment, 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.

Intangible assets with an indefinite life are not amortized but are subject to review each reporting period to determine whether events and circumstances continue to support an indefinite useful life as well as an annual impairment test. Due to the continued decline in crude oil prices, the Company updated its goodwill impairment analysis as of September 30, 2015, resulting in the fair value of one reporting unit to be less than its carrying value. An impairment charge of $33.8 million was recorded on goodwill as a result of this step 2 analysis. An impairment charge of $36.0 million was recorded on goodwill in 2014. No impairment was recognized on goodwill in 2013 based upon the quantitative and qualitative assessments.

Definite Lived Intangible Assets

Definite lived intangible assets consist of intangible assets associated with customer relationships, supplier agreements, tradenames, trade secrets, patents, non-competition agreements, distributor agreements and royalty agreements that were acquired in various acquisitions. The majority of these assets are being amortized using discounted estimated future cash flows over the term of the related agreements. Intangible assets associated with customer relationships are being amortized using the discounted estimated future cash flows method based upon assumed rates of annual customer attrition. For more information, refer to Note 5.

Other Noncurrent Assets

Other noncurrent assets include turnaround costs. Turnaround costs represent capitalized costs associated with the Company’s periodic major maintenance and repairs and were $60.4 million and $70.1 million as of December 31, 2015 and 2014, respectively. The Company capitalizes these costs and amortizes the costs on a straight-line basis over the lives of the turnaround assets. These amounts are net of accumulated amortization of $71.6 million and $46.2 million at December 31, 2015 and 2014, respectively.

Other Current Liabilities

Other current liabilities consisted of the following at December 31, 2015 and 2014 (in millions):

	December 31,	
	2015	2014
RINs Obligation	$88.4	$16.3
Other	30.6	23.7
Total	$119.0	$40.0

The Company’s Renewable Identification Numbers obligation (“RINs Obligation”) represents a liability for the purchase of RINs to satisfy the U.S. Environmental Protection Agency (“EPA”) requirement to blend biofuels into the fuel products it produces pursuant to the EPA’s Renewable Fuel Standard (“RFS”). RINs are assigned to biofuels produced in the U.S. as required by the EPA. The EPA sets annual quotas for the percentage of biofuels that must be blended into transportation fuels consumed in the U.S., and as a producer of motor fuels from petroleum, the Company is required to blend biofuels into the fuel products it produces at a rate that will meet the EPA’s annual quota. To the extent the Company is unable to blend biofuels at that rate, it must purchase RINs in the open market to satisfy the annual requirement. The Company’s RINs Obligation is based on the amount of RINs it must purchase and the price of those RINs as of the balance sheet date. The Company uses the inventory model to account for RINs, measuring acquired RINs at weighted-average cost. The cost of RINs used each period is charged to cost of sales with cash inflows and outflows recorded in the operating cash flow section of the consolidated statements of cash flows. Excess RINs are classified as inventory in the consolidated balance sheets. The Company recognizes a liability at the end of each reporting period in which the Company does not have sufficient RINs to cover the RINs Obligation. The liability is calculated by multiplying the RINs shortage (based on actual results) by the period end RIN spot price.

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

Impairment of Long-Lived Assets

The Company periodically evaluates the carrying value of long-lived assets to be held and used, including definite-lived intangible assets, when events or circumstances warrant such a review. The carrying value of a long-lived asset to be held and used is considered impaired when the anticipated separately identifiable undiscounted cash flows from such an asset are less than the carrying value of the asset. In such an event, a write-down of the asset would be recorded through a charge to operations, based on the amount by which the carrying value exceeds the fair value of the long-lived asset. Fair value is determined primarily using anticipated cash flows assumed by a market participant discounted at a rate commensurate with the risk involved. Long-lived assets to be disposed of other than by sale are considered held and used until disposal.

During 2013, the Company recorded write-downs related to idle fixed assets within its specialty products segment. The non-cash charges of $10.5 million were recorded in asset impairment on the consolidated statements of operations and loss on disposal of fixed assets in the consolidated statements of cash flows for the year ended December 31, 2013. No impairments of long-lived assets were recorded in 2015 and 2014.

Business Combinations and Related Business Acquisition Costs

Assets and liabilities associated with business acquisitions are recorded at fair value, using the acquisition method of accounting. The Company allocates the purchase price of acquisitions based upon the fair value of each component, which may be derived from various observable or unobservable inputs and assumptions. The Company may utilize third-party valuation specialists to assist the Company in this allocation. Initial purchase price allocations are preliminary and subject to revision within the measurement period, not to exceed one year from the date of acquisition. 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 identifiable assets acquired and liabilities assumed.

Business acquisition costs are expensed as incurred, and are reported as general and administrative expenses in the consolidated statements of operations. The Company defines these costs to include finder’s fees, advisory, legal, accounting, valuation, and other professional or consulting fees, as well as travel associated with the evaluation and effort to acquire specific businesses. For further information, refer to Note 3.

Revenue Recognition

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

Concentrations of Credit Risk

The Company performs periodic credit evaluations of its customers’ financial condition and in some instances requires cash in advance or letters of credit prior to shipment for domestic orders. For international orders, letters of credit are generally required and the Company maintains insurance policies which cover certain export orders. The Company maintains an allowance for doubtful customer accounts for estimated losses resulting from the inability of its customers to make required payments. The allowance for doubtful accounts is developed based on several factors including historical experience, the age of the accounts receivable balances, credit quality of the Company’s customers, current economic conditions, expected future trends and other factors that may affect customers’ ability to pay, which exist as of the balance sheet dates. If the financial condition of the Company’s customers were to deteriorate, resulting in an impairment of their ability to make payments, additional allowances may be required. In addition, from time to time the Company has significant derivative assets with a limited number of counterparties. The evaluation of these counterparties is performed quarterly in connection with the Company's ASC 820-10, Fair Value Measurements and Disclosures, valuations to determine the impact of the counterparty credit risk on the valuation of its derivative instruments.

Income Taxes

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

In the event that the Company’s taxable income does not meet certain qualification requirements, the Company would be taxed as a corporation. Interest and penalties related to income taxes, if any, would be recorded in income tax expense. Generally, tax returns remain subject to examination by taxing authorities for three years. The Company had no unrecognized tax benefits as of December 31, 2015 and 2014.

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

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

Excise and Sales Taxes

The Company assesses, collects and remits excise taxes associated with the sale of certain of its fuel products. Furthermore, the Company collects and remits sales taxes associated with certain sales of its products to non-exempt customers. Excise taxes and sales taxes assessed and collected from customers are recorded on a net basis within sales in the Company’s consolidated statements of operations.

Earnings per Unit

The Company calculates earnings per unit under ASC 260-10, Earnings per Share. The Company treats incentive distribution rights (“IDRs”) as participating securities for the purposes of computing earnings per unit in the period that the general partner becomes contractually obligated to receive IDRs. Also, the undistributed earnings are allocated to the partnership interests based on the allocation of earnings to the Company’s partners’ capital accounts as specified in the Company’s partnership agreement. When distributions exceed earnings, net income is reduced by the actual distributions with the resulting net loss being allocated to capital accounts as specified in the Company’s partnership agreement.

Unit Based Compensation

For unit based compensation awards granted, compensation expense is recognized in the Company’s consolidated financial statements on a straight line basis over the awards’ vesting periods based on their fair values on the dates of grant. The unit based compensation awards vest over a period not exceeding four years. The amount of compensation expense recognized at any date is at least equal to the portion of the grant date value of the award that is vested at that date.

Unit based compensation liability awards are awards that are expected to be settled in cash on their vesting dates, rather than in equity units (“Liability Awards”). Liability Awards are recorded in accrued salaries, wages and benefits based on the vested portion of the fair value of the awards on the balance sheet date. The fair values of Liability Awards are updated at each balance sheet date and changes in the fair values of the vested portions of the awards are recorded as increases or decreases to compensation expense. See Note 11 for more information on Liability Awards.

Shipping and Handling Costs

The Company complies with ASC 605-45, Revenue Recognition — Principal Agent Considerations. ASC 605-45 requires the classification of shipping and handling costs billed to customers in sales and the classification of shipping and handling costs incurred in cost of sales, or to be disclosed if classified elsewhere. The Company has reflected $175.5 million, $171.4 million and $142.7 million, respectively, for the years ended December 31, 2015, 2014, and 2013, in transportation expense in the consolidated statements of operations, the majority of which is billed to customers.

Table of Contents

Advertising Expenses

The Company expenses advertising costs as incurred which totaled $14.2 million, $20.5 million and $14.6 million in 2015, 2014 and 2013, respectively. Advertising expenses are reported as selling expenses in the consolidated statements of operations.

Foreign Currency Translation and Transactions

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

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

New Accounting Pronouncements

In January 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-01, Financial Instruments — Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities ("ASU 2016-01"). ASU 2016-01 requires that (i) equity investments in unconsolidated entities that are not accounted for under the equity method of accounting generally be measured at fair value with changes recognized in net income and (ii) when the fair value option has been elected for financial liabilities, changes in fair value due to instrument-specific credit risk be recognized separately in other comprehensive income. Additionally, ASU 2016-01 changes the presentation and disclosure requirements for financial instruments. The amendments in this standard are effective for fiscal years (including interim periods) beginning after December 15, 2017, with early adoption not permitted. The Company is currently evaluating the impact of this standard on its consolidated financial statements.

In November 2015, the FASB issued ASU No. 2015-17, Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes ("ASU 2015-17"). ASU 2015-17 requires that businesses classify deferred tax liabilities and assets on their balance sheets as noncurrent. Under existing accounting, a business must separate deferred income tax liabilities and assets into current and noncurrent. The amendments in this standard may be applied retrospectively or prospectively and are effective for fiscal years (including interim periods) beginning after December 15, 2016, with early adoption permitted. The Company adopted ASU 2015-17 retrospectively, which resulted in the Company reclassifying approximately $2.3 million, as of December 31, 2014, of deferred income taxes from current assets to noncurrent deferred income taxes in the consolidated balance sheets.

In September 2015, the FASB issued ASU No. 2015-16, Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments ("ASU 2015-16"). ASU 2015-16 requires that an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. The amendments in this standard are effective prospectively for fiscal years (including interim periods) beginning after December 15, 2015, with early adoption permitted. The adoption of ASU 2015-16 is not expected to have an impact on the Company's consolidated financial statements.

In June 2015, the FASB issued ASU No. 2015-10, Technical Corrections and Improvements ("ASU 2015-10"). With regard to fair value measurement disclosures, ASU 2015-10 clarified that, for nonrecurring measurements estimated at a date during the reporting period other than the end of the reporting period, an entity should clearly indicate that the fair value information presented is not as of the period's end as well as the date or period that the measurement was taken. The Company adopted ASU 2015-10, effective June 12, 2015, as the change was effective upon issuance. The adoption did not have an impact on the Company's consolidated financial statements.

In May 2015, the FASB issued ASU No. 2015-08, Business Combinations (Topic 805): Pushdown Accounting — Amendments to SEC Paragraphs Pursuant to Staff Bulletin No. 115 ("ASU 2015-08"). The amendments in ASU 2015-08 amend various SEC paragraphs included in the FASB's Accounting Standards Codification to reflect the issuance of Staff Accounting Bulletin No. 115 ("SAB 115"). SAB 115 rescinds portions of the interpretive guidance included in the SEC's Staff Accounting Bulletins series and brings existing guidance into conformity with ASU No. 2014-17, "Business Combinations (Topic 805): Pushdown Accounting," which provides an acquired entity with an option to apply pushdown accounting in its separate financial statements upon occurrence of an event in which an acquirer obtains control of the acquired entity. The Company adopted the amendments in ASU 2015-08, effective May 8, 2015, as the amendments in the update are effective upon issuance. The adoption did not have an impact on the Company's consolidated financial statements.

Table of Contents
CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

In May 2015, the FASB issued ASU No. 2015-07, Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent) ("ASU 2015-07"). ASU 2015-07 provides guidance that amends the required disclosure of investments for which fair value is measured at net asset value ("NAV") per share (or its equivalent). The amendments remove the requirement to make certain disclosures for all investments that are eligible to be measured at fair value using the NAV per share practical expedient. ASU 2015-07 is effective for fiscal periods (including interim periods) beginning after December 15, 2015, with early adoption permitted. ASU 2015-07 should be applied retrospectively. The adoption of ASU 2015-07 is not expected to have an impact on the Company's consolidated financial statements.

In April 2015, the FASB issued ASU No. 2015-06, Earnings per Share (Topic 260): Effects on Historical Earnings per Unit of Master Limited Partnership Dropdown Transactions ("ASU 2015-06"). ASU 2015-06 provides guidance for calculating historical earnings per unit under the two-class method, stating that the earnings or losses of a transferred business before the date of a dropdown transaction should be allocated entirely to the general partner interest. ASU 2015-06 is effective for fiscal periods (including interim periods) beginning after December 15, 2015, with early adoption permitted. ASU 2015-06 should be applied retrospectively. The adoption of ASU 2015-06 is not expected to have an impact on the Company's consolidated financial statements.

In April 2015, the FASB issued ASU No. 2015-05, Intangibles — Goodwill and Other — Internal-Use Software (Subtopic 350-40): Customer's Accounting for Fees Paid in a Cloud Computing Arrangement ("ASU 2015-05"). ASU 2015-05 provides guidance to determine whether a cloud computing agreement includes a software license or should be considered as a service agreement. ASU 2015-05 is effective for fiscal periods (including interim periods) beginning after December 15, 2015, with early adoption permitted. An entity can elect to adopt the amendments either (1) prospectively to all arrangements entered into or materially modified after the effective date or (2) retrospectively. The adoption of ASU 2015-05 is not expected to have an impact on the Company's consolidated financial statements.

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

In April 2015, the FASB issued ASU No. 2015-03, Interest — Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs ("ASU 2015-03"). ASU 2015-03 requires debt issuance costs to be recognized in the balance sheet as a direct deduction from the related debt liability rather than as an asset. ASU 2015-03 also requires the amortization of debt issuance costs to be reported as interest expense. ASU 2015-03 is effective for fiscal periods (including interim periods) beginning after December 15, 2015, with early adoption permitted. ASU 2015-03 must be applied retrospectively, where the balance sheet of each presented individual period is adjusted to indicate the period-specific impact of using the new guidance. In August 2015, the FASB issued ASU 2015-15, Interest — Imputation of Interest (Subtopic 835-30): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements ("ASU 2015-15"), which states that an entity can defer and present debt issuance costs as an asset and subsequently amortize the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. The Company adopted ASU 2015-03, which resulted in the Company reclassifying approximately $34.7 million, as of December 31, 2014, of deferred debt issuance costs from other noncurrent assets to long-term debt in the consolidated balance sheets.

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

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606) ("ASU 2014-09"), which supersedes the revenue recognition requirements in Accounting Standards Codification 605, Revenue Recognition. ASU 2014-09 is based on the principle that revenue is recognized to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 also requires additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts, including significant judgments and changes in judgments and assets recognized from costs incurred to obtain or fulfill a contract. ASU 2014-09 was originally effective for fiscal periods (including interim periods) beginning after December 15, 2016. In August 2015, the FASB issued ASU 2015-14, Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date, which defers the effective date by one year, with early adoption permitted as of the original effective date. ASU 2014-09 allows for either a full retrospective or a modified retrospective transition method. The Company is currently evaluating the impact of this standard on its consolidated financial statements.

3. Acquisitions

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

On March 31, 2014, the Company completed the acquisition of 100% of the capital stock of ADF Holdings, Inc., the parent company of Anchor Drilling Fluids USA, Inc. (“Anchor”), an independent provider and marketer of drilling fluids and completion fluids to the oil and gas exploration industry (the “Anchor Acquisition”). Total consideration was approximately $223.6 million, net of cash acquired. In connection with the Anchor Acquisition, the Company is required to pay the sellers 50% of the amount of taxes paid in a post-closing tax period that are reduced (or a refund is actually received or credited) as a result of the utilization of post-closing transaction tax deductions in the 2014 taxable year (but, for the avoidance of doubt, no other taxable year), which is estimated to be $1.1 million as of December 31, 2015. Anchor designs, manufactures and packages drilling fluid products at its locations in Texas, Oklahoma, Louisiana, Arkansas, Colorado, Utah, Wyoming, Montana, New Mexico, New York, North Dakota, Pennsylvania and Ohio. The Anchor Acquisition was financed by using a portion of the net proceeds of approximately $884.0 million from the Company’s March 2014 private placement of 6.50% Senior Notes due 2021. The Company believes the Anchor Acquisition further expands its specialty products offering, increases its sales into the oilfield services market, expands its geographic reach and increases its asset diversity.

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

On December 10, 2013, the Company completed the acquisition of 100% of the membership interests of Bel-Ray Company, LLC (“Bel-Ray”), a manufacturer and global distributor of high-performance lubricants and greases, for aggregate consideration of approximately $53.6 million, net of cash acquired and excluding debt assumed (“Bel-Ray Acquisition”). Bel-Ray distributes, both domestically and internationally, a wide array of high-end specialty synthetic lubricants and greases which are used in the aerospace, automotive, energy, food, marine, military, mining, motorcycle, powersports, steel and textiles industries. The Bel-Ray Acquisition was financed by using a portion of the net proceeds of $337.4 million from the Company’s November 2013 private placement of 7.625% senior notes due January 15, 2022. The Company believes the Bel-Ray Acquisition increases its position in the specialty lubricants market, expands its geographic reach and increases its asset diversity. At closing, the Company repaid the $11.9 million of debt assumed in connection with the Bel-Ray Acquisition.

On August 9, 2013, the Company completed the acquisition of seven crude oil loading facilities and related assets in North Dakota and Montana from Murphy Oil USA, Inc. (“Murphy”) for aggregate consideration of approximately $6.2 million (“Crude Oil Logistics Acquisition”). The Crude Oil Logistics Acquisition was funded with cash on hand. As part of this acquisition, the Company assumed pipeline space on the Enbridge Pipeline System (“Enbridge Pipeline”) previously held by Murphy. The Company has the ability to transport crude oil directly from the point of lease, into the Company’s acquired crude oil loading facilities and then onto the Enbridge Pipeline where it can be routed to the Company’s Superior refinery and/or third party customers. As part of this transaction, the Company and Murphy jointly consented to terminate an existing crude oil purchase agreement wherein Murphy supplied the Company’s

Superior refinery with up to 10,000 bpd of crude oil. The Company believes this acquisition expands its growing portfolio of crude oil logistics assets, while positioning the Company to purchase increased volumes of price-advantaged feedstock directly from the producers that operate in the major shale oil plays encompassing certain of the Company's refineries.

On January 2, 2013, the Company completed the acquisition of NuStar Energy L.P.'s ("NuStar") San Antonio, Texas, refinery, together with related assets and the assumption of certain liabilities and obligations ("San Antonio Acquisition"). Total consideration for the San Antonio Acquisition was approximately $117.9 million, net of cash acquired. The refinery has total crude oil throughput capacity of 21,000 bpd and primarily produces diesel, jet fuel, gasoline, other fuel products and solvents. The San Antonio Acquisition was funded with borrowings under the Company's revolving credit facility with the balance through cash on hand. The Company believes the San Antonio Acquisition further diversifies the Company's crude oil feedstock slate, operating asset base and geographic presence.

Table of Contents
CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Purchase Price Allocation

The assets and results of the operations from such assets acquired as a result of the San Antonio and Crude Oil Logistics Acquisitions have been included in the fuel products segments since their dates of acquisition, January 2, 2013, and August 9, 2013, respectively. The assets and results of operations from such assets acquired as a result of the Bel-Ray and United Petroleum Acquisitions have been included in the specialty products segment since their dates of acquisition, December 10, 2013, and February 28, 2014, respectively. The assets and results of operations from such assets acquired as a result of the Anchor and SOS Acquisitions have been included in the oilfield services segment since their dates of acquisition, March 31, 2014, and August 1, 2014, respectively.

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

	2014 Acquisitions			2013 Acquisitions		
	SOS	Anchor	United Petroleum	Bel-Ray	Crude Oil Logistics	San Antonio
Accounts receivable	$11.6	$75.0	$—	$4.3	$—	$—
Inventories	2.7	61.2	0.2	11.1	—	17.0
Prepaid expenses and other current assets	0.1	0.4	—	0.6	0.1	—
Deposits	—	0.6	—	—	—	—
Deferred tax asset	—	0.9	—	—	—	—
Property, plant and equipment, net	15.1	35.9	—	6.5	0.9	100.7
Investment in unconsolidated affiliates	—	1.9	—	—	—	—
Goodwill	0.8	69.0	5.0	9.1	5.2	5.7
Other intangible assets, net	5.7	74.0	5.2	41.4	—	—
Other noncurrent assets, net	—	—	—	0.3	—	—
Accounts payable	(6.2)	(44.2)	—	(3.9)	—	—
Accrued salaries, wages and benefits	—	(18.2)	—	(1.3)	—	(0.1)
Accrued income taxes payable	—	—	—	—	—	—
Other taxes payable	(0.2)	(1.8)	—	(1.7)	—	—
Other current liabilities	—	(0.4)	—	(0.8)	—	(5.4)
Current portion of long-term debt	—	—	—	(11.9)	—	—
Long-term debt	—	—	—	—	—	—
Deferred income tax liability	—	(30.7)	—	—	—	—
Other long-term liabilities	—	—	—	(0.1)	—	—
Pension and postretirement benefit obligations	—	—	—	—	—	—
Total purchase price, net of cash acquired	$29.6	$223.6	$10.4	$53.6	$6.2	$117.9

Table of Contents
CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Intangible Assets

The components of intangible assets listed in the table above were as follows (in millions):

	SOS August 1, 2014		Anchor March 31, 2014		United Petroleum February 28, 2014		Bel-Ray December 10, 2013	
	Amount	Life (Years)	Amount	Life (Years)	Amount	Life (Years)	Amount	Life (Years)
Customer relationships	$4.3	15	$52.7	20	$3.8	20	$28.6	30
Tradenames	1.4	20	18.4	21	1.4	20	4.2	18
Trade secrets	—	—	—	—	—	—	8.5	18
Non-competition agreements	—	—	2.9	2	—	—	0.1	3
Totals	$5.7		$74.0		$5.2		$41.4	
Weighted average amortization period		16		20		20		26

Goodwill

The Company recorded the following goodwill (in millions):

	Amount	Business Segment
SOS Acquisition (1)	$0.8	Oilfield Services
Anchor Acquisition (1) (3)	$69.0	Oilfield Services
United Petroleum Acquisition (1)	$5.0	Specialty Products
Bel-Ray Acquisition (1)	$9.1	Specialty Products
Crude Oil Logistics Acquisition (2)	$5.2	Fuel Products
San Antonio Acquisition (1)	$5.7	Fuel Products

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

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

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

Acquisition Expenses

In connection with the respective acquisitions, the Company incurred the following expenses, which are reflected in general and administrative expenses in the consolidated statements of operations for the years ended December 31, 2015, 2014 and 2013 (in millions):

	Year Ended December 31,		
	2015	2014	2013
SOS Acquisition	$—	$0.1	$—
Anchor Acquisition	$—	$0.6	$—
United Petroleum Acquisition	$—	$0.1	$—
Bel-Ray Acquisition	$—	$0.3	$0.4
Crude Oil Logistics Acquisition	$—	$—	$0.2
San Antonio Acquisition	$—	$—	$0.5
Montana Acquisition	$—	$—	$0.1

Table of Contents

Results of Sales and Earnings

The following financial information reflects sales and operating income (loss) of the Anchor Acquisition that are included in the consolidated statements of operations (in millions):

	Year Ended December 31,		
	2015	2014	2013
Sales	$259.8	$349.1	$—
Operating loss	$(74.5)	$(19.1)	$—

Unaudited Pro Forma Financial Information

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

	Year Ended December 31, 2014
Sales	$5,873.6
Net loss	$(124.6)
Limited partners' interest basic and diluted net loss per unit	$(1.97)

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

4. Investment in Unconsolidated Affiliates

The following table summarizes the Company's investments in unconsolidated affiliates for the years ended of December 31, 2015 and 2014 (in millions):

	Year Ended December 31, 2015		Year Ended December 31, 2014	
	Investment	Percent Ownership	Investment	Percent Ownership
Dakota Prairie Refining, LLC	$124.7	50%	$117.2	50%
Juniper GTL LLC	—	—%	18.5	23%
Other	1.3		1.6	
Total	$126.0		$137.3	

Dakota Prairie Refining, LLC

On February 7, 2013, the Company entered into a joint venture agreement with MDU Resources Group, Inc. ("MDU") to develop, build and operate a diesel refinery in southwestern North Dakota. The joint venture is named Dakota Prairie Refining, LLC ("Dakota Prairie"). The capitalization of the construction cost was funded through cash contributions from MDU, cash contributions from the Company and proceeds of $75.0 million from a syndicated term loan facility with the joint venture as the borrower, which is expected to be repaid by the Company through its allocation of profits from the joint venture. The term loan facility was funded in April 2013. In addition to the $300.0 million commitment outlined in the joint venture agreement, MDU and the Company made additional cash contributions, net of distributions, in the amount of $80.4 million and $88.6 million, respectively, to fund construction costs and working capital needs. Additionally, MDU and the Company may make cash contributions to fund working capital needs. The joint venture allocates profits on a 50%/50% basis to the Company and MDU, except for the adjustments made to the Company's share for repayment of the principal and interest of the $75.0 million term loan as noted above. The joint venture is governed by a board of managers comprised of representatives from both the Company and MDU. MDU is providing natural gas and electricity utility services to the joint venture. The Company is providing refinery operations, crude oil procurement and refined product marketing expertise to the joint venture. Dakota Prairie commenced sales of finished products in May 2015.

On September 30, 2015, the Company entered into an agreement with MDU and Dakota Prairie, under which Dakota Prairie can borrow up to $25.0 million from each of the Company and MDU through June 30, 2016, (the “Subordinated Loan”). The

Subordinated Loan is subordinated in right of payment to Dakota Prairie's obligations under its revolving credit facility pursuant to the terms of a Subordination Agreement between the Company, MDU, Dakota Prairie and Wells Fargo Bank, N.A., as representative of the lenders under the revolving credit facility. As of December 31, 2015, there are no amounts outstanding under the Subordinated Loan.

On September 30, 2015, the Company issued a $39.4 million letter of credit supporting Dakota Prairie's $75.0 million revolving credit agreement, which expires July 6, 2016.

During the year ended December 31, 2015, the Company purchased $2.6 million of crude oil and other feedstocks at cost from Dakota Prairie. Accounts payable to Dakota Prairie at December 31, 2015, were $1.4 million for crude oil and other feedstock purchases.

During the year ended December 31, 2015, the Company purchased $4.6 million of crude oil on behalf of Dakota Prairie and sold it to Dakota Prairie at cost, which resulted in an immaterial gain. Other receivables from Dakota Prairie at December 31, 2015, were $0.4 million.

In the event Dakota Prairie is unable to sell atmospheric towers bottoms ("ATB's") to a third party at or above acquisition costs, or in the event third party sales do not cover crude oil acquisition costs, the joint venture agreement requires the Company to either buy the ATB's or cover any shortfall between the third party sales and the crude oil acquisition cost. During the year ended December 31, 2015, the Company paid $1.1 million of shortfall under the agreement. Accounts payable to Dakota Prairie at December 31, 2015, were $0.7 million related to the shortfall agreement.

The Company subleased railcars from Dakota Prairie in 2015 and 2014. The amount charged for these subleases totaled $0.6 million in 2015 and 2014. There were no accounts payable as of December 31, 2015 related to the railcar subleases. Accounts payable were $0.5 million as of December 31, 2014 related to the railcar subleases.

On January 1, 2015, the Company entered into an agreement with Dakota Prairie to provide administrative services to Dakota Prairie. The amount charged for these services during the year ended December 31, 2015 was $0.4 million. Other accounts receivable from Dakota Prairie at December 31, 2015 were immaterial.

The Company provides certain services to Dakota Prairie, which include costs for payroll and certain other employee benefits. The amount related to such services was $0.2 million in 2015 and $0.4 million in 2014.

The Company's membership interest in Dakota Prairie is significant as defined by the Securities and Exchange Commission's ("SEC") Regulation S-X Rule 1-02(w). Accordingly, as required by Regulation S-X Rule 3-09, the Company has included the audited financial statements of Dakota Prairie as of and for the year ended December 31, 2015, as an exhibit to this Annual Report on Form 10-K.

Juniper GTL LLC

On June 9, 2014, the Company entered into a joint venture agreement with Clean Fuels North America, LLC, which is owned by SGC Energia and Great Northern Project Development, to develop, build and operate a gas-to-liquids ("GTL") plant in Lake Charles, Louisiana. The joint venture is named New Source Fuels, LLC, and it owns 100% of Juniper GTL LLC ("Juniper"). The Company invested $25.0 million in total in exchange for an equity interest of approximately 23% in the joint venture. During September 2015, the Company determined the fair value of its investment in Juniper was less than its carrying value of $24.3 million. As a result, the Company recorded a $24.3 million impairment charge in loss from unconsolidated affiliates in the consolidated statement of operations for the year ended December 31, 2015. Inputs used to estimate the fair value of Juniper was considered Level 3 of the fair value hierarchy.

5. Goodwill and Other Intangible Assets

During September 2015, the Company determined that the expected operating results for one of its reporting units was projected to be substantially lower than previous forecasts due to the continued decline in crude oil prices. As a result, the Company determined that these recent events constituted a triggering event that required the Company to update its goodwill impairment assessment through September 30, 2015. An impairment charge of $33.8 million for goodwill related to the oilfield services segment has been recorded in the consolidated statements of operations within asset impairment. The impairment charge was primarily driven by the reduced outlook on revenues and profitability as a result of falling crude oil prices driving declines in U.S. land based rig counts.

To derive the fair value of the reporting units, as required in step one of the impairment test, the Company used the income approach, specifically the discounted cash flow method, to determine the fair value of each reporting unit and the associated amount of the impairment charge. The income approach focuses on the income-producing capability of an asset, measuring the current value of the asset by calculating the present value of its future economic benefits such as cash earnings, cost savings, corporate tax structure and product offerings. Value indications are developed by discounting expected cash flows to their present value at a rate of return that incorporates the risk-free rate for the use of funds, the expected rate of inflation, and risks associated with the reporting unit.

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

- The Company's financial projections for its reporting units are based on its analysis of various supply and demand factors, which include, among other things, industry-wide capacity, planned utilization rate, end-user demand, crack spreads, capital expenditures and economic conditions. Such estimates are consistent with those used in the Company's planning and capital investment reviews and include recent historical prices and published forward prices. Revenue growth rates assumed for the Company's reporting unit where impairment was recognized were approximately (17)% for 2015 and ranged from (3)% to 18% for 2016 and beyond.
- The discount rate used to measure the present value of the projected future cash flows is based on a variety of factors, including market and economic conditions, operational risk, regulatory risk and political risk. This discount rate is also compared to recent observable market transactions, if possible. The discount rate used for the Company's reporting unit where impairment was recognized was approximately 15.5% per year.

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

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

	Specialty Products	Fuel Products	Oilfield Services	Total
Net balance as of December 31, 2013	$168.5	$38.5	$—	$207.0
Acquisitions [1]	5.0	—	69.8	74.8
Impairment [2]	—	—	(36.0)	(36.0)
Net balance as of December 31, 2014	$173.5	$38.5	$33.8	$245.8
Impairment [2]	—	—	(33.8)	(33.8)
Net balance as of December 31, 2015	$173.5	$38.5	$—	$212.0

(1) See Note 3 for discussion of the acquisitions completed during 2014.

(2) Total accumulated goodwill impairment as of December 31, 2015 and 2014, is $69.8 million and $36.0 million, respectively.

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

	Weighted Average Life (Years)	December 31, 2015 Gross Amount	December 31, 2015 Accumulated Amortization	December 31, 2014 Gross Amount	December 31, 2014 Accumulated Amortization
Customer relationships	21	$243.7	$(97.5)	$243.7	$(68.4)
Supplier agreements	4	21.5	(21.5)	21.5	(21.5)
Tradenames	16	46.6	(10.7)	46.6	(4.9)
Trade secrets	13	52.7	(23.4)	52.7	(16.7)
Patents	12	1.6	(1.4)	1.6	(1.3)
Non-competition agreements	4	8.8	(8.8)	8.8	(7.3)
Distributor agreements	3	2.0	(2.0)	2.0	(2.0)
Royalty agreements	19	4.5	(2.0)	4.5	(1.8)
	18	$381.4	$(167.3)	$381.4	$(123.9)

Supplier agreements, tradenames (other than indefinite lived), trade secrets, patents, non-competition agreements, distributor agreements and royalty agreements are being amortized to properly match expenses with the undiscounted estimated future cash flows over the terms of the related agreements or the period expected to be benefited. The costs of agreements with terms allowing for the potential extension of such agreements are being amortized based on the initial term only. Customer relationships are being amortized using undiscounted estimated future cash flows based upon assumed rates of annual customer attrition. For the years ended December 31, 2015, 2014 and 2013, the Company recorded amortization expense of intangible assets of $43.4 million, $40.3 million and $25.6 million, respectively.

As of December 31, 2015, the Company estimates that amortization of intangible assets for the next five years will be as follows (in millions):

Year	Amortization Amount
2016	$37.2
2017	$32.3
2018	$27.3
2019	$22.8
2020	$18.8

6. Commitments and Contingencies

Operating Leases

The Company has various operating leases primarily for the use of land, storage tanks, railcars, equipment, precious metals and office facilities that extend through July 2055. Renewal options are available on certain of these leases in which the Company is the lessee. Rent expense for the years ended December 31, 2015, 2014 and 2013 was $67.8 million, $59.9 million and $35.3 million, respectively.

As of December 31, 2015, the Company had estimated minimum commitments for the payment of rentals under leases which, at inception, had a noncancelable term of more than one year, as follows (in millions):

Year	Operating Leases
2016	$42.8
2017	37.9
2018	33.3
2019	22.2
2020	16.9
Thereafter	27.0
Total	$180.1

Crude Oil Supply, Other Feedstocks and Finished Products

The Company is currently purchasing a majority of its crude oil under month-to-month evergreen contracts or on a spot basis.

The Company entered into a Crude Oil Purchase Agreement (the “BP Purchase Agreement”) with BP Products North America Inc. (“BP”), pursuant to which BP supplies the Superior refinery with a portion of its daily crude oil requirements, utilizing a market-based pricing mechanism, plus transportation and handling costs. Total crude oil requirements for the Superior refinery are estimated to be between 35,000 and 45,000 bpd. The BP Purchase Agreement, as amended and restated, had an initial term of one year ending April 1, 2014, and automatically renews for successive one-year terms unless terminated by either party upon 90 days’ notice prior to the end of any renewal term. To secure a portion of the Company’s payment obligations under the BP Purchase Agreement, the Company and its affiliates have granted a limited interest, capped at $100.0 million, for physical forwards in the collateral pledged as security under the Collateral Trust Agreement to BP as a “Forward Purchase Secured Hedge Counterparty” under its Collateral Trust Agreement, as such term is defined therein.

Certain other feedstocks are purchased under long-term supply contracts. The Company also purchases finished products from Houston Refining. The Company is required to purchase all of the naphthenic lubricating oils produced at Houston Refining’s refinery in Houston, Texas, up to 3,100 bpd, and has a right of first refusal to purchase any additional naphthenic lubricating oils (above the 3,100 bpd) produced at the refinery. In addition, Houston Refining is required to toll-process a minimum of approximately 600 bpd of white mineral oil for the Company at Houston Refining's Houston, Texas refinery. The annual purchase commitment under these agreements is approximately $87.5 million.

As of December 31, 2015, the estimated minimum purchase commitments under the Company's crude oil, other feedstock supply and finished product agreements were as follows (in millions):

Year	Commitment
2016	$493.6
2017	149.8
2018	87.6
2019	80.3
2020	—
Thereafter	—
Total	$811.3

The Company has a feedstock purchase agreement with Phillips 66 related to the LVT unit at its Lake Charles, Louisiana refinery (the "LVT Feedstock Agreement"). Pursuant to the LVT Feedstock Agreement, Phillips 66 is obligated to supply a minimum quantity (the "Base Volume") of feedstock for the LVT unit for a term of ten years. Based upon this minimum supply quantity, the Company expects to purchase approximately $27.5 million of feedstock for the LVT unit in each fiscal year of the term of the contract expiring January 1, 2018, based on pricing estimates as of December 31, 2015. This amount is not included in the table above.

Contingencies

From time to time, the Company is a party to certain claims and litigation incidental to its business, including claims made by various taxation and regulatory authorities, such as the EPA, various state environmental regulatory bodies, the Internal Revenue Service, various state and local departments of revenue and the federal Occupational Safety and Health Administration ("OSHA"), as the result of audits or reviews of the Company's business. In addition, the Company has property, business interruption, general liability and various other insurance policies that may result in certain losses or expenditures being reimbursed to the Company.

Environmental

The Company conducts crude oil and specialty hydrocarbon refining, blending and terminal operations in addition to providing oilfield services and products, which activities are subject to stringent federal, state, regional and local laws and regulations governing worker health and safety, the discharge of materials into the environment and environmental protection. These laws and regulations impose obligations that are applicable to the Company's operations, such as requiring the acquisition of permits to conduct regulated activities, restricting the manner in which the Company may release materials into the environment, requiring remedial activities or capital expenditures to mitigate pollution from former or current operations, requiring the application of specific health and safety criteria addressing worker protection and imposing substantial liabilities for pollution resulting from its operations. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil and criminal penalties; the imposition of investigatory, remedial or corrective action obligations or the incurrence of capital expenditures; the occurrence of delays in the permitting, development or expansion of projects, and the issuance of injunctive relief limiting or prohibiting Company activities. Moreover, certain of these laws impose joint and several, strict liability for costs required to remediate and restore sites where petroleum hydrocarbons, wastes or other materials have been released or disposed. In addition, new laws and regulations, new interpretations of existing laws and regulations, increased governmental enforcement or other developments, some of which legal requirements are discussed below, could significantly increase the Company's operational or compliance expenditures.

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

San Antonio Refinery

In connection with the San Antonio Acquisition (see Note 3), the Company agreed to indemnify NuStar for an unlimited term and without consideration of a monetary deductible or cap from any environmental liabilities associated with the San Antonio refinery, except for any governmental penalties or fines that may result from NuStar's actions or inactions during NuStar's 20-month period of ownership of the San Antonio refinery. Anadarko Petroleum Corporation ("Anadarko") and Age Refining, Inc. ("Age Refining"), a third party that has since entered bankruptcy, are subject to a 1995 Agreed Order from the Texas Natural Resource Conservation Commission, now known as the Texas Commission on Environmental Quality, pursuant to which Anadarko and Age Refining are obligated to assess and remediate certain contamination at the San Antonio refinery that predates the Company's acquisition of the facility. The Company does not expect this pre-existing contamination at the San Antonio refinery to have a material adverse effect on its financial position or results of operations.

Montana Refinery

In connection with the acquisition of the Montana refinery from Connacher Oil and Gas Limited ("Connacher"), the Company became a party to an existing 2002 Refinery Initiative Consent Decree (the "Montana Consent Decree") with the EPA and the Montana Department of Environmental Quality (the "MDEQ"). The material obligations imposed by the Montana Consent Decree have been completed. On September 27, 2012, Montana Refining Company, Inc. received a final Corrective Action Order on Consent, replacing the refinery's previously held hazardous waste permit. This Corrective Action Order on Consent governs the investigation and remediation of contamination at the Montana refinery. The Company believes the majority of damages related to such contamination at the Montana refinery are covered by a contractual indemnity provided by HollyFrontier Corporation ("Holly"), the owner and operator of the Montana refinery prior to its acquisition by Connacher, under an asset purchase agreement between Holly and Connacher, pursuant to which Connacher acquired the Montana refinery. Under this asset purchase agreement, Holly agreed to indemnify Connacher and Montana Refining Company, Inc., subject to timely notification, certain conditions and certain monetary baskets and caps, for environmental conditions arising under Holly's ownership and operation of the Montana refinery and existing as of the date of sale to Connacher. During 2014, Holly provided the Company a notice challenging the Company's position that Holly is obligated to indemnify the Company's remediation expenses for environmental conditions to the extent arising under Holly's ownership and operation of the refinery and existing as of the date of sale to Connacher, which expenses totaled approximately $17.6 million as of December 31, 2015, of which $14.4 million was capitalized into the cost of the Company's recently completed expansion project and $3.2 million was expensed. The Company continues to believe that Holly is responsible to indemnify the Company for these remediation expenses disputed by Holly, and on September 22, 2015, the Company initiated a lawsuit against Holly and the sellers of the Montana refinery under the asset purchase agreement. On November 24, 2015, Holly and the sellers of the Montana refinery under the asset purchase agreement filed a motion to dismiss the case pending arbitration. The Company is opposing the motion. In the event the Company is unsuccessful, the Company will be responsible for those remediation expenses. The Company expects that it may incur some costs to remediate other environmental conditions at the Montana refinery; however, the Company believes at this time that these other costs it may incur will not be material to its financial position or results of operations.

Superior Refinery

In connection with the acquisition of the Superior refinery, the Company became a party to an existing Refinery Initiative Consent Decree ("Superior Consent Decree") with the EPA and the Wisconsin Department of Natural Resources ("WDNR") that applies, in part, to its Superior refinery. Under the Superior Consent Decree, the Company must complete certain reductions in air emissions at the Superior refinery as well as report upon certain emissions from the refinery to the EPA and the WDNR. The Company estimates costs of up to $4.0 million to make known equipment upgrades and conduct other discrete tasks in compliance with the Superior Consent Decree. Failure to perform these required tasks under the Superior Consent Decree could result in the imposition of stipulated penalties, which could be material. The Company is currently assessing certain past actions at the refinery for compliance with the terms of the Superior Consent Decree, which actions may be subject to stipulated penalties under the Superior Consent Decree but, in any event, the Company does not currently believe that the imposition of such penalties for those actions, should they be imposed, would be material. In addition, the Company is pursuing certain additional environmental and safety-related projects at the Superior refinery. Completion of these additional projects will result in the Company incurring additional costs, which could be substantial. During 2015, the Company incurred no costs related to installing process equipment at the Superior refinery pursuant to the EPA fuel content regulations. During 2014, the Company incurred approximately $0.7 million of costs related to installing process equipment at the

Superior refinery pursuant to the EPA fuel content regulations.

On June 29, 2012, the EPA issued a Finding of Violation/Notice of Violation to the Superior refinery, which included a proposed penalty amount of $0.1 million. This finding is in response to information provided to the EPA by the Company in response to an information request. The EPA alleges that the efficiency of the flares at the Superior refinery is lower than regulatory requirements. The Company is contesting the allegations and is in settlement discussions with the EPA to resolve this issue. The Company has not yet received formal action from the EPA. The Company does not believe that the resolution of these allegations will have a material adverse effect on the Company’s financial position or results of operations.

The Company is contractually indemnified by Murphy Oil Corporation (“Murphy Oil”) under an asset purchase agreement between the Company and Murphy Oil for specified environmental liabilities arising from the operation of the Superior refinery including: (i) certain obligations arising out of the Superior Consent Decree (including payment of a civil penalty required under the Superior Consent Decree), (ii) certain liabilities arising in connection with Murphy Oil’s transport of certain wastes and other materials to specified offsite real properties for disposal or recycling prior to the Superior Acquisition and (iii) certain liabilities for certain third party actions, suits or proceedings alleging exposure, prior to the Superior Acquisition, of an individual to wastes or other materials at the specified on-site real property, which wastes or other materials were spilled, released, emitted or otherwise discharged by Murphy Oil. The Company believes contractual indemnity by Murphy Oil for such specified environmental liabilities is unlimited in duration and not subject to any monetary deductibles or maximums. The amount of any damages payable by Murphy Oil pursuant to the contractual indemnities under the asset purchase agreement are net of any amount recoverable under an environmental insurance policy that the Company obtained in connection with the Superior Acquisition, which named the Company and Murphy Oil as insureds and covers environmental conditions existing at the Superior refinery prior to the Superior Acquisition.

Shreveport, Cotton Valley and Princeton Refineries

On December 23, 2010, the Company entered into a settlement agreement with the Louisiana Department of Environmental Quality ("LDEQ") under LDEQ's "Small Refinery and Single Site Refinery Initiative," covering the Shreveport, Princeton and Cotton Valley refineries. This settlement agreement became effective on January 31, 2012. The settlement agreement, termed the "Global Settlement," resolved alleged violations of the federal Clean Air Act and federal Clean Water Act regulations that arose prior to December 23, 2010. Among other things, the Company agreed to complete beneficial environmental programs and implement emissions reduction projects at the Company's Shreveport, Cotton Valley and Princeton refineries on an agreed-upon schedule. During 2015 and 2014, the Company incurred approximately $6.8 million and $0.6 million, respectively, of such expenditures and estimates additional expenditures of approximately $3.0 million to $5.0 million of capital expenditures and expenditures related to additional personnel and environmental studies through 2016 as a result of the implementation of these requirements. These capital investment requirements 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 position or results of operations.

The Company is contractually indemnified by Shell Oil Company ("Shell"), as successor to Pennzoil-Quaker State Company, and Atlas Processing Company, under an asset purchase agreement between the Company and Shell, for specified environmental liabilities arising from the operations of the Shreveport refinery prior to the Company's acquisition of the facility. The Company believes the contractual indemnity is unlimited in amount and duration, but requires the Company to contribute $1.0 million of the first $5.0 million of indemnified costs for certain of the specified environmental liabilities.

Bel-Ray Facility

Bel-Ray executed an Administrative Consent Order ("ACO") with the New Jersey Department of Environmental Protection, effective January 4, 1994, which required investigation and remediation of contamination at or emanating from the Bel-Ray facility. In 2000, Bel-Ray entered into a fixed price remediation contract with Weston Solutions ("Weston"), a large remediation contractor, whereby Weston agreed to be fully liable for the remediation of the soil and groundwater issues at the facility, including an offsite groundwater plume pursuant to the ACO ("Weston Agreement"). The Weston Agreement set up a trust fund to reimburse Weston, administered by Bel-Ray's environmental counsel. As of December 31, 2015, the trust fund contained approximately $0.8 million. In addition, Weston has remediation cost containment insurance, should Weston be unable to complete the work required under the Weston Agreement. In connection with the Bel-Ray Acquisition, the Company became a party to the Weston Agreement.

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

Occupational Health and Safety

The Company is subject to various laws and regulations relating to occupational health and safety, including OSHA and comparable state laws. These laws and regulations strictly govern the protection of the health and safety of employees. In addition, OSHA's hazard communication standard requires that information be maintained about hazardous materials used or produced in the Company's operations and that this information be provided to employees, contractors, state and local government authorities and customers. The Company maintains safety and training programs as part of its ongoing efforts to ensure compliance with applicable laws and regulations. The Company conducts periodic audits of Process Safety Management ("PSM") systems at each of its locations subject to the PSM standard. The Company's compliance with applicable health and safety laws and regulations has required, and continues to require, substantial expenditures. Changes in occupational safety and health laws and regulations or a finding of non-compliance with current laws and regulations could result in additional capital expenditures or operating expenses, as well as civil penalties and, in the event of a serious injury or fatality, criminal charges.

The Company has completed studies to assess the adequacy of its PSM practices at its Shreveport refinery with respect to certain consensus codes and standards. During the years ended December 31, 2015 and 2014, the Company incurred approximately $0.6 million and $1.1 million, respectively, of PSM related capital expenditures and expects to incur up to $1.4 million of capital expenditures during 2016 to address OSHA compliance issues identified in these studies. The Company expects these capital expenditures will enhance its equipment such that the equipment maintains compliance with applicable consensus codes and standards.

In the first quarter of 2011, OSHA conducted an inspection of the Cotton Valley refinery's PSM program. On March 14, 2011, OSHA issued a Citation and Notification of Penalty (the "Cotton Valley Citation") to the Company as a result of the Cotton Valley inspection, which included a proposed penalty amount of $0.2 million. The Company has contested the Cotton Valley Citation and the parties have reached a tentative settlement with OSHA on the matter, which the Company does not believe will have a material adverse effect on its financial position or results of operations.

Labor Matters

The Company has approximately 613 employees covered by various collective bargaining agreements, or approximately 28% of its total workforce of approximately 2,175 employees. These agreements have expiration dates of March 31, 2016, April 30, 2016, June 30, 2017, October 31, 2017, and January 31, 2019. The Company has approximately 241 employees, or approximately 11% of its total workforce, covered by collective bargaining agreements that expire in less than one year and does not expect any work stoppages.

Legal Proceedings

The Company is involved in the legal proceedings described below and is subject to other claims and litigation arising in the normal course of its business. The Company has recorded accruals with respect to certain of these matters, where appropriate, that are reflected in its consolidated financial statements but are not, individually or in the aggregate, considered material. For other matters, the Company has not recorded accruals because it has not yet determined that a loss is probable or because the amount of loss cannot be reasonably estimated. While the ultimate outcome of the matters described below and other claims and litigation currently pending cannot be determined, the Company currently does not expect that these proceedings and claims, individually or in the aggregate, will have a material adverse effect on its financial position, results of operations or cash flows. The outcome of any litigation is inherently uncertain, however, and if decided adversely to the Company, or if the Company determines that settlement of particular litigation is appropriate, the Company may be subject to liability that could have a material adverse effect on its financial position, results of operations, or cash flows. Accordingly, the Company discloses matters below for which a material loss is reasonably possible. In each case, however, the Company has either determined that the range of loss is not reasonably estimable or that any reasonably estimable range of loss is not material to its consolidated financial statements.

On November 12, 2014, a nationwide collective action lawsuit alleging that Anchor, a wholly owned subsidiary of the Company, failed to pay drilling fluid engineers overtime in compliance with the Fair Labor Standards Act ("FLSA") was filed titled Jonathan Wolfe v. Anchor Drilling Fluids USA, Inc. in the U.S. District Court for the Western District of Pennsylvania ("Wolfe"). The Company filed its answer to the complaint on January 9, 2015 and the Wolfe plaintiff filed an amended complaint on February 26, 2015, adding that Anchor's failure to pay overtime to a subclass of drilling fluid engineers violated the Pennsylvania Minimum Wage Act (the "Pennsylvania Act"). For this subclass, the Wolfe plaintiff seeks certification of a class action under the Pennsylvania Act. The Wolfe plaintiff seeks to recover overtime pay, liquidated damages and attorneys' fees and costs. The portion of the potential liability that relates to the period prior to March 31, 2014, the date on which the Company acquired Anchor, is eligible for indemnification under the securities purchase agreement that effected that transaction; however, the right to indemnification under the securities purchase agreement for the potential Wolfe liability is subject to a deductible and limitations otherwise set forth in the securities purchase agreement. On May 1, 2015, the parties engaged in mediation and agreed to a tentative settlement of this litigation. On September 3, 2015, the U.S. District Court entered an order granting preliminary approval of the settlement as well as attorneys' fees and costs. On January 6, 2016, a final judgment was entered by the U.S. District Court approving the settlement. The settlement amount is not material to the consolidated financial statements.

On November 21, 2014, a nationwide collective action lawsuit alleging that Anchor and the Company, as well as SOS, failed to pay solids control technicians overtime in compliance with the FLSA was filed titled Timothy Niver v. Specialty Oilfield Solutions, Ltd., et al. in the U.S. District Court for the Western District of Pennsylvania ("Niver"). The Niver plaintiff filed an amended complaint on January 21, 2015, adding that defendants' failure to pay overtime to a subclass of solids control technicians violated the Pennsylvania Act. For this subclass, the Niver plaintiff seeks certification of a class action under the Pennsylvania Act. The Niver plaintiff seeks to recover overtime pay, liquidated damages and attorneys' fees and costs. Anchor and the Company filed their answer to the amended complaint on February 2, 2015. The Company consented to conditional certification in the case, and notice of the collective action has been issued to potential class members. The portion of the potential liability that relates to the period prior to August 1, 2014, the date on which the Company acquired the assets of SOS, was retained by, and is the responsibility of, SOS. To the extent Anchor or the Company is found liable for damages relating to the period prior to the acquisition of the assets of SOS, Anchor and the Company are eligible for indemnification under the asset purchase agreement that effected that transaction, and no deductible is applicable; however, the right to indemnification is subject to limitations otherwise set forth in the asset purchase agreement. On June 1, 2015, the parties engaged in mediation and agreed to a tentative settlement of this litigation. On October 7, 2015, the U.S. District Court entered an order approving the settlement and dismissing the case with prejudice. The settlement amount was not material to the consolidated financial statements.

Standby Letters of Credit

The Company has agreements with various financial institutions for standby letters of credit which have been issued primarily to vendors. As of December 31, 2015 and 2014, the Company had outstanding standby letters of credit of $66.8 million and $114.3 million, respectively, under its senior secured revolving credit facility, which was amended and restated on July 14, 2014 (the "revolving credit facility"). Refer to Note 7 for additional information regarding the Company's revolving credit facility. At December 31, 2015 and 2014, the maximum amount of letters of credit the Company could issue under its revolving credit facility was subject to borrowing base limitations, with a maximum letter of credit sublimit equal to $600.0 million, which amount may be increased to 90% of revolver commitments in effect ($1.0 billion at December 31, 2015) with the consent of the Agent (as defined in the revolving credit facility agreement).

As of December 31, 2015 and 2014, the Company had availability to issue letters of credit of $233.5 million and $310.8 million, respectively, under its revolving credit facility.

7. Long-Term Debt

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

	December 31, 2015	December 31, 2014
Borrowings under amended and restated senior secured revolving credit agreement with third-party lenders, interest payments quarterly, borrowings due July 2019, weighted average interest rates of 3.3% and 2.6% at December 31, 2015 and 2014, respectively	$111.0	$150.8
Borrowings under 2020 Notes, interest at a fixed rate of 9.625%, interest payments semiannually, borrowings due August 2020, effective interest rate of 10.1% for each year ended December 31, 2015 and 2014	—	275.0
Borrowings under 2021 Notes, interest at a fixed rate of 6.50%, interest payments semiannually, borrowings due April 2021, effective interest rates of 6.8% and 6.7% for the year ended December 31, 2015 and 2014, respectively	900.0	900.0
Borrowings under 2022 Notes, interest at a fixed rate of 7.625%, interest payments semiannually, borrowings due January 2022, effective interest rate of 8.0% for each year ended December 31, 2015 and 2014 (1)	352.9	352.5
Borrowings under 2023 Notes, interest at a fixed rate of 7.75%, interest payments semiannually, borrowings due April 2023, effective interest rate of 8.0% for the year ended December 31, 2015	325.0	—
Related party note payable, interest at a fixed rate of 6.0% on a portion of the note, interest payments at various dates, borrowings due July 2016, weighted average interest rate of 6% for the year ended December 31, 2015	73.5	—
Capital lease obligations, at various interest rates, interest and principal payments monthly through October 2034	46.4	43.6
Less unamortized debt issuance costs (2)	(28.9)	(34.7)
Less unamortized discounts	(6.5)	(8.4)
Total long-term debt	1,773.4	1,678.8
Less current portion of note payable - related party	73.5	—
Less current portion of long-term debt	1.7	0.6
	$1,698.2	$1,678.2

(1) The balance includes a fair value interest rate hedge adjustment, which increased the debt balance by $2.9 million and $2.5 million as of December 31, 2015 and 2014, respectively (refer to Note 8 for additional information on the interest rate swap designated as a fair value hedge).

(2) Deferred debt issuance costs are being amortized by the effective interest rate method over the lives of the related debt instruments. These amounts are net of accumulated amortization of $8.1 million and $4.3 million at December 31, 2015 and 2014, respectively.

Senior Notes

7.75% Senior Notes (the “2023 Notes”)

On March 27, 2015, the Company issued and sold $325.0 million in aggregate principal amount of 7.75% Senior Notes due April 15, 2023 in a private placement pursuant to Section 4(a)(2) of the Securities Act of 1933, as amended (the “Securities Act”), to eligible purchasers at a discounted price of 99.257 percent of par. The 2023 Notes were resold to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to persons outside the U.S. pursuant to Regulation S under the Securities Act. The Company received net proceeds of approximately $317.0 million net of discount, initial purchasers’ fees and expenses, which the Company used to fund the redemption of $178.8 million in aggregate principal amount of outstanding 2020 Notes (defined below) on April 28, 2015, to repay borrowings outstanding under its revolving credit facility and for general partnership purposes, including planned capital expenditures at the Company’s facilities and working capital. Interest on the 2023 Notes is paid semiannually in arrears on April 15 and October 15 of each year, beginning on October 15, 2015.

At any time prior to April 15, 2018, the Company may on any one or more occasions redeem up to 35% of the aggregate principal amount of the 2023 Notes with the net proceeds of a public or private equity offering at a redemption price of 107.75% of the principal amount, plus any accrued and unpaid interest to the date of redemption, provided that: (1) at least 65% of the aggregate principal amount of 2023 Notes issued remains outstanding immediately after the occurrence of such redemption and (2) the redemption occurs within 180 days of the date of the closing of such public or private equity offering.

On and after April 15, 2018, the Company may on any one or more occasions redeem all or a part of the 2023 Notes at the redemption prices (expressed as percentages of principal amount) set forth below, plus accrued and unpaid interest to the applicable redemption date on such 2023 Notes, if redeemed during the twelve-month period beginning on April 15 of the years indicated below:

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

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

On March 27, 2015, in connection with the issuance and sale of the 2023 Notes, the Company entered into a registration rights agreement with the initial purchasers of the 2023 Notes obligating the Company to use reasonable best efforts to file an exchange offer registration statement with the SEC, so that holders of the 2023 Notes can offer to exchange the 2023 Notes for registered notes having substantially the same terms as the 2023 Notes and evidencing the same indebtedness as the 2023 Notes. On December 11, 2015, the Company filed an exchange offer registration statement for the 2023 Notes with the SEC, which was declared effective on January 28, 2016. The exchange offer is expected to be completed on February 29, 2016, thereby fulfilling all of the requirements of the 2023 Notes registration rights agreement.

6.50% Senior Notes (the “2021 Notes”)

On March 31, 2014, the Company issued and sold $900.0 million in aggregate principal amount of 6.50% senior notes due April 15, 2021 in a private placement pursuant to Section 4(a)(2) of the Securities Act of 1933, as amended (the “Securities Act”), to eligible purchasers at par. The Company received net proceeds of approximately $884.0 million, net of initial purchasers’ fees and expenses, which the Company used to fund the purchase price of the Anchor Acquisition (refer to Note 3 for additional information), the redemption of $500.0 million in aggregate principal

amount outstanding of 9.375% senior notes due 2019 (“2019 Notes”) and for general partnership purposes, including planned capital expenditures at the Company’s facilities. Interest on the 2021 Notes is paid semiannually in arrears on April 15 and October 15 of each year, beginning on October 15, 2014.
At any time prior to April 15, 2017, the Company may on any one or more occasions redeem up to 35% of the aggregate principal amount of the 2021 Notes with the net proceeds of a public or private equity offering at a redemption price of 106.5% of the principal amount, plus any accrued and unpaid interest to the date of redemption, provided that: (1) at least 65% of the aggregate principal amount of 2021 Notes issued remains outstanding immediately after the occurrence of such redemption and (2) the redemption occurs within 180 days of the date of the closing of such public or private equity offering.

Table of Contents

On and after April 15, 2017, the Company may on any one or more occasions redeem all or a part of the 2021 Notes at the redemption prices (expressed as percentages of principal amount) set forth below, plus any accrued and unpaid interest to the applicable redemption date on such 2021 Notes, if redeemed during the twelve-month period beginning on April 15 of the years indicated below:

Year	Percentage	
2017	103.250	%
2018	101.625	%
2019 and thereafter	100.000	%

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

On March 31, 2014, in connection with the issuance and sale of the 2021 Notes, the Company entered into a registration rights agreement with the initial purchasers of the 2021 Notes obligating the Company to use reasonable best efforts to file an exchange offer registration statement with the SEC, so that holders of the 2021 Notes can offer to exchange the 2021 Notes for registered notes having substantially the same terms as the 2021 Notes and evidencing the same indebtedness as the 2021 Notes. On March 24, 2015, the Company filed an exchange offer registration statement for the 2021 Notes with the SEC, which was declared effective on April 3, 2015. The exchange offer was completed on April 30, 2015, thereby fulfilling all of the requirements of the 2021 Notes registration rights agreement.

7.625% Senior Notes (the “2022 Notes”)

On November 26, 2013, the Company issued and sold $350.0 million in aggregate principal amount of 7.625% senior notes due January 15, 2022, in a private placement pursuant to Section 4(a)(2) of the Securities Act, to eligible purchasers at a discounted price of 98.494 percent of par. The 2022 Notes were resold to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to persons outside the U.S. pursuant to Regulation S under the Securities Act. The Company received net proceeds of $337.4 million, net of discount, initial purchasers’ fees and expenses, which the Company used for general partnership purposes, to fund previously announced organic growth projects, to fund the purchase price of the Bel-Ray Acquisition and the redemption of $100.0 million in aggregate principal amount outstanding of 2019 Notes. Refer to Note 3 for additional information regarding the Bel-Ray Acquisition. Interest on the 2022 Notes is paid semiannually in arrears on January 15 and July 15 of each year, beginning on July 15, 2014.

At any time prior to January 15, 2017, the Company may on any one or more occasions redeem up to 35% of the aggregate principal amount of the 2022 Notes with the net proceeds of a public or private equity offering at a redemption price of 107.625% 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 2022 Notes issued remains outstanding immediately after the occurrence of such redemption and (2) the redemption occurs within 180 days of the date of the closing of such public or private equity offering.

On and after January 15, 2018, the Company may on any one or more occasions redeem all or a part of the 2022 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 2022 Notes, if redeemed during the twelve-month period beginning on January 15 of the years indicated below:

Year	Percentage	
2018	103.813	%
2019	101.906	%
2020 and thereafter	100.000	%

Prior to January 15, 2018, the Company may on any one or more occasions redeem all or part of the 2022 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 2022 Notes) at the redemption date, plus any accrued and unpaid interest to the applicable redemption date.

On November 26, 2013, in connection with the issuance and sale of the 2022 Notes, the Company entered into a registration rights agreement with the initial purchasers of the 2022 Notes obligating the Company to use reasonable best efforts to file an exchange offer registration statement with the SEC, so that holders of the 2022 Notes can offer to exchange the 2022 Notes for registered notes having substantially the same terms as the 2022 Notes and evidencing the same indebtedness as the 2022 Notes.

On November 27, 2013, the Company filed an exchange offer registration statement for the 2022 Notes with the SEC, which was declared effective on December 10, 2013. The exchange offer was completed on January 13, 2014, thereby fulfilling all of the requirements of the 2022 Notes registration rights agreement.

9.625% Senior Notes (the "2020 Notes")

On June 29, 2012, in connection with the acquisition of Royal Purple, the Company issued and sold $275.0 million in aggregate principal amount of 9.625% senior notes due August 1, 2020 in a private placement pursuant to Section 4(a)(2) of the Securities Act, to eligible purchasers at a discounted price of 98.25 percent of par. The 2020 Notes were resold to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to persons outside the U.S. pursuant to Regulation S under the Securities Act. The Company received net proceeds of $262.5 million, net of discount, initial purchasers' fees and expenses, which the Company used to fund a portion of the purchase price of Royal Purple.

On April 27, 2015, the Company redeemed $96.2 million aggregate principal amount of 2020 Notes with a portion of the net proceeds of the March 13, 2015 public offering of its common units in which it sold 6,000,000 common units. Additionally, on April 28, 2015, the Company redeemed the remaining $178.8 million aggregate principal amount of 2020 Notes with a portion of the net proceeds from the issuance of the 2023 Notes. In conjunction with the redemptions, the Company incurred debt extinguishment costs of $46.6 million.

2021 Notes, 2022 Notes and 2023 Notes

In accordance with SEC Rule 3-10 of Regulation S-X, condensed consolidated financial statements of non-guarantors are not required. The Company has no assets or operations independent of its subsidiaries. Obligations under its 2021, 2022 and 2023 Notes are fully and unconditionally and jointly and severally guaranteed on a senior unsecured basis by the Company's current 100%-owned operating subsidiaries and certain of the Company's future operating subsidiaries, with the exception of the Company's "minor" subsidiaries (as defined by Rule 3-10 of Regulation S-X), including Calumet Finance Corp. (100%-owned Delaware corporation that was organized for the sole purpose of being a co-issuer of certain of the Company's indebtedness, including the 2021, 2022 and 2023 Notes). There are no significant restrictions on the ability of the Company or subsidiary guarantors for the Company to obtain funds from its subsidiary guarantors by dividend or loan. None of the subsidiary guarantors' assets represent restricted assets pursuant to SEC Rule 4-08(e)(3) of Regulation S-X.

The 2021, 2022 and 2023 Notes are subject to certain automatic customary releases, including the sale, disposition, or transfer of capital stock or substantially all of the assets of a subsidiary guarantor, designation of a subsidiary guarantor as unrestricted in accordance with the applicable indenture, exercise of legal defeasance option or covenant defeasance option, liquidation or dissolution of the subsidiary guarantor and a subsidiary guarantor ceases to both guarantee other Company debt and to be an obligor under the revolving credit facility. The Company's operating subsidiaries may not sell or otherwise dispose of all or substantially all of their properties or assets to, or consolidate with or merge into, another company if such a sale would cause a default under the indentures governing the 2021, 2022 and 2023 Notes.

The indentures governing the 2021, 2022 and 2023 Notes contain covenants that, among other things, restrict the Company's ability and the ability of certain of the Company's subsidiaries to: (i) sell assets; (ii) pay distributions on, redeem or repurchase the Company's common units or redeem or repurchase its subordinated debt; (iii) make investments; (iv) incur or guarantee additional indebtedness or issue preferred units; (v) create or incur certain liens; (vi) enter into agreements that restrict distributions or other payments from the Company's restricted subsidiaries to the Company; (vii) consolidate, merge or transfer all or substantially all of the Company's assets; (viii) engage in transactions with affiliates and (ix) create unrestricted subsidiaries. These covenants are subject to important exceptions and qualifications. At any time when the 2021, 2022 and 2023 Notes are rated investment grade by either Moody's Investors Service, Inc. ("Moody's") or Standard & Poor's Ratings Services ("S&P") and no Default or Event of Default, each as defined in the indentures governing the 2021, 2022 and 2023 Notes, has occurred and is continuing, many of these covenants will be suspended. As of December 31, 2015, the Company’s Fixed Charge Coverage Ratio (as defined in the indentures governing the 2021, 2022 and 2023 Notes) was 1.9 to 1.0.

Second Amended and Restated Senior Secured Revolving Credit Facility

The Company has a $1.0 billion senior secured revolving credit facility, subject to borrowing base limitations, which includes a $500.0 million incremental uncommitted expansion feature. The revolving credit facility is the Company’s primary source of liquidity for cash needs in excess of cash generated from operations. The revolving credit facility matures in July 2019 and currently bears interest at a rate equal to prime plus a basis points margin or London Interbank Offered Rate (“LIBOR”) plus a basis points margin, at the Company’s option. As of December 31, 2015, the margin was 75 basis points for prime and 175 basis points for LIBOR; however, the margin can fluctuate quarterly based on the Company’s average availability for additional borrowings under the revolving credit facility in the preceding calendar quarter as follows:

Table of Contents

CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

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

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

The borrowing capacity at December 31, 2015, under the revolving credit facility was $411.3 million. As of December 31, 2015, the Company had $111.0 million in outstanding borrowings under the revolving credit facility and outstanding standby letters of credit of $66.8 million, leaving $233.5 million available for additional borrowings based on specified availability limitations. Lenders under the revolving credit facility have a first priority lien on the Company’s accounts receivable, inventory and substantially all of its cash.

The revolving credit facility contains various covenants that limit, among other things, the Company’s ability to: incur indebtedness; grant liens; dispose of certain assets; make certain acquisitions and investments; redeem or prepay other debt or make other restricted payments such as distributions to unitholders; enter into transactions with affiliates and enter into a merger, consolidation or sale of assets. Further, the revolving credit facility contains one springing financial covenant which provides that only if the Company’s availability under the revolving credit facility falls below the greater of (a) 12.5% of the Borrowing Base (as defined in the revolving credit agreement) then in effect and (b) $45.0 million, then the Company will be required to maintain as of the end of each fiscal quarter a Fixed Charge Coverage Ratio (as defined in the revolving credit agreement) of at least 1.0 to 1.0.

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

Master Derivative Contracts

The Company’s payment obligations under all of the Company’s master derivatives contracts for commodity hedging generally are secured by a first priority lien on the Company’s 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). The Company had no additional letters of credit or cash margin posted with any hedging counterparty as of December 31, 2015. The Company’s master derivatives contracts and Collateral Trust Agreement (as defined below) continue to impose a number of covenant limitations on the Company’s operating and financing activities, including limitations on liens on collateral, limitations on dispositions of collateral and collateral maintenance and insurance requirements.

Collateral Trust Agreement

The Company has a collateral sharing agreement (the “Collateral Trust Agreement”) with each of its secured hedging counterparties and an administrative agent for the benefit of the secured hedging counterparties, which governs how the secured hedging counterparties will share collateral pledged as security for the payment obligations owed by the Company to the 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, the Company has the ability to add secured hedging counterparties from time to time.

Related Party Note Payable

On December 30, 2015, the Company entered into an agreement with The Heritage Group ("Heritage"), an affiliate of the Company's general partner, in which Heritage made a $27.0 million uncommitted prepayment for the purchase of certain finished products and entered into a $48.0 million unsecured note payable with the Company as the borrower. Imputed interest on the prepayment totaled $1.5 million. The note bears interest at 6.0%, with interest payments due on March 31, 2016, June 30, 2016, and July 31, 2016. Principal payments of $15.0 million each are due on May 31, 2016 and June 30, 2016, with the remaining principal amount due before July 31, 2016. The proceeds were used for general partnership purposes.

Capital Leases

Assets recorded under these capital lease obligations are included in property, plant and equipment and total $49.0 million and $48.9 million as of December 31, 2015 and 2014, respectively. As of December 31, 2015 and 2014, the Company had recorded $3.9 million and $5.7 million, respectively, in accumulated depreciation for these capital lease assets.

On July 7, 2014, the Company entered into a capital lease agreement with TexStar Midstream Logistics, L.P. (“TexStar”) under which TexStar constructed, owns and operates a 30,000 bpd crude oil pipeline system supplying significant volumes of Eagle Ford crude oil to the Company’s San Antonio refinery for a term of 20 years. Thereafter, the agreement will continue on a month-to-month basis unless terminated by either party. Under the terms of the agreement, TexStar installed and operates the Karnes North Pipeline System (“KNPS”), a pipeline that transports crude oil from Karnes City, Texas, to the San Antonio refinery’s Elmendorf, Texas, terminal, a key supply hub for the San Antonio refinery. The Company expects to receive deliveries of at least 12,000 bpd of crude oil through the KNPS-Elmendorf terminal supply route. The pipeline became fully operational on November 1, 2014. The total obligation and asset under the capital lease agreement as of December 31, 2015 and 2014, was $39.4 million and $39.3 million, respectively. Total depreciation expense for this lease during the years ended December 31, 2015 and 2014, was $2.0 million and $0.3 million, respectively.

As of December 31, 2015, the Company had estimated minimum commitments for the payment of total rentals under capital leases as follows (in millions):

Year	Capital Leases
2016	$8.2
2017	7.9
2018	7.8
2019	7.4
2020	6.9
Thereafter	96.2
Total minimum lease payments	134.4
Less amount representing interest	88.0
Capital lease obligations	46.4
Less obligations due within one year	1.7
Long-term capital lease obligations	$44.7

Maturities of Long-Term Debt

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

Year	Maturity
2016	$76.7
2017	1.6
2018	1.5
2019	112.3
2020	0.9
Thereafter	1,614.4
Total	$1,807.4

8. Derivatives

The Company is exposed to price risks due to fluctuations in the price of crude oil, refined products (primarily in the Company’s fuel products segment), natural gas and precious metals. The Company uses various strategies to reduce its exposure to commodity price risk. The strategies to reduce the Company’s risk utilize both physical forward contracts and financially settled derivative instruments, such as swaps, collars and options, to attempt to reduce the Company’s exposure with respect to:

- crude oil purchases and sales;

Table of Contents

- fuel product sales and purchases;
- natural gas purchases;
- precious metals purchases: and
- fluctuations in the value of crude oil between geographic regions and between the different types of crude oil such as NYMEX West Texas Intermediate ("NYMEX WTI"), Light Louisiana Sweet ("LLS"), Western Canadian Select ("WCS"), Mixed Sweet Blend ("MSW") and ICE Brent ("Brent").

The Company manages its exposure to commodity markets, credit, volumetric and liquidity risks to manage its costs and volatility of cash flows as conditions warrant or opportunities become available. These risks may be managed in a variety of ways that may include the use of derivative instruments. Derivative instruments may be used for the purpose of mitigating risks associated with an asset, liability and anticipated future transactions. The changes in fair value of the Company's derivative instruments will affect its earnings and cash flows; however, such changes should be offset by price or rate changes related to the underlying commodity or financial transaction that is part of the risk management strategy. The Company does not speculate with derivative instruments or other contractual arrangements that are not associated with its business objectives. Speculation is defined as increasing the Company's natural position above the maximum position of its physical assets or trading in commodities, currencies or other risk bearing assets that are not associated with the Company's business activities and objectives. The Company's positions are monitored routinely by a risk management committee to ensure compliance with its stated risk management policy and documented risk management strategies. All strategies are reviewed on an ongoing basis by the Company's risk management committee, which will add, remove or revise strategies in anticipation of changes in market conditions and/or in risk profiles. These changes in strategies are to position the Company in relation to its risk exposures in an attempt to capture market opportunities as they arise.

The Company recognizes all derivative instruments at their fair values (see Note 9) as either current assets or current liabilities in the consolidated balance sheets. Fair value includes any premiums paid or received and unrealized gains and losses. Fair value does not include any amounts receivable from or payable to counterparties, or collateral provided to counterparties. Derivative asset and liability amounts with the same counterparty are netted against each other for financial reporting purposes. The Company's financial results are subject to the possibility that changes in a derivative's fair value could result in significant ineffectiveness and potentially no longer qualify portions or all of its derivative instruments for hedge accounting.

Table of Contents
CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following tables summarize the Company's gross fair values of its derivative instruments, presenting the impact of offsetting derivative assets in the Company's consolidated balance sheets as of December 31, 2015 and 2014 (in millions):

	December 31, 2015			December 31, 2014		
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts of Assets Presented in the Consolidated Balance Sheets	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts of Assets Presented in the Consolidated Balance Sheets
Derivative instruments designated as hedges:						
Fuel products segment:						
Crude oil swaps	$—	$—	$—	$—	$(10.0)	$(10.0)
Gasoline swaps	—	—	—	15.9	(4.4)	11.5
Swaps not allocated to a specific segment:						
Interest rate swaps	—	—	—	2.5	—	2.5
Total derivative instruments designated as hedges	—	—	—	18.4	(14.4)	4.0
Derivative instruments not designated as hedges:						
Specialty products segment:						
Natural gas swaps	—	—	—	—	(7.2)	(7.2)
Natural gas collars	—	—	—	0.1	(0.6)	(0.5)
Platinum swaps	—	—	—	—	(0.1)	(0.1)
Fuel products segment:						
Crude oil swaps	—	—	—	31.4	(111.2)	(79.8)
Crude oil basis swaps	0.4	(0.4)	—	0.8	—	0.8
Crude oil percentage basis swaps	0.2	(0.2)	—	—	(0.2)	(0.2)
Crude oil options	0.8	(0.8)	—	—	—	—
Gasoline swaps	—	—	—	2.4	(0.4)	2.0
Diesel swaps	—	—	—	116.1	(19.1)	97.0
Diesel crack spread swaps	—	—	—	4.5	—	4.5
Jet fuel swaps	—	—	—	7.9	(5.2)	2.7
Total derivative instruments not designated as hedges	1.4	(1.4)	—	163.2	(144.0)	19.2
Total derivative instruments	$1.4	$(1.4)	$—	$181.6	$(158.4)	$23.2

118

The following tables summarize the Company's gross fair values of its derivative instruments, presenting the impact of offsetting derivative liabilities in the Company's consolidated balance sheets as of December 31, 2015 and 2014 (in millions):

	December 31, 2015			December 31, 2014		
	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts of Liabilities Presented in the Consolidated Balance Sheets	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts of Liabilities Presented in the Consolidated Balance Sheets
Derivative instruments designated as hedges:						
Fuel products segment:						
Crude oil swaps	$—	$—	$—	$(13.8)	$10.0	$(3.8)
Gasoline swaps	—	—	—	—	4.4	4.4
Total derivative instruments designated as hedges	—	—	—	(13.8)	14.4	0.6
Derivative instruments not designated as hedges:						
Specialty products segment:						
Natural gas swaps	(14.9)	—	(14.9)	(12.1)	7.2	(4.9)
Natural gas collars	(0.9)	—	(0.9)	(1.1)	0.6	(0.5)
Platinum swaps	—	—	—	(0.1)	0.1	—
Fuel products segment:						
Crude oil swaps	(5.2)	—	(5.2)	(102.4)	111.2	8.8
Crude oil basis swaps	(0.7)	0.4	(0.3)	—	—	—
Crude oil percentage basis swaps	(6.9)	0.2	(6.7)	(0.2)	0.2	—
Crude oil options	(1.1)	0.8	(0.3)	—	—	—
Gasoline swaps	—	—	—	(1.0)	0.4	(0.6)
Gasoline crack spread swaps	(4.3)	—	(4.3)	—	—	—
Diesel swaps	—	—	—	(28.1)	19.1	(9.0)
Jet fuel swaps	—	—	—	(5.2)	5.2	—
Natural gas swaps	(1.3)	—	(1.3)	—	—	—
Total derivative instruments not designated as hedges	(35.3)	1.4	(33.9)	(150.2)	144.0	(6.2)
Total derivative instruments	$(35.3)	$1.4	$(33.9)	$(164.0)	$158.4	$(5.6)

The Company is exposed to credit risk in the event of nonperformance by its counterparties on these derivative transactions. The Company does not expect nonperformance on any derivative instruments, however, no assurances can be provided. The Company's credit exposure related to these derivative instruments is represented by the fair value of contracts reported as derivative assets. As of December 31, 2015, the Company had no counterparties in which derivatives held were net assets. As of December 31, 2014, the Company had five counterparties, in which derivatives held were net assets, totaling $23.2 million. To manage credit risk, the Company selects and periodically reviews counterparties based on credit ratings. The Company primarily executes its derivative instruments with large financial institutions that have ratings of at least Baa1 and BBB+ by Moody's Investor Service, Inc. ("Moody's") and Standard & Poor's Ratings Services ("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 December 31, 2015 or December 31, 2014. The Company's contracts with these counterparties allow for netting of derivative instruments executed under each contract. Collateral received from counterparties is reported in other current liabilities, and collateral held by counterparties is reported in deposits, on the Company's consolidated balance sheets and is not netted against derivative assets or liabilities. Any outstanding collateral is released to the Company upon settlement of the related derivative instrument liability. As of December 31, 2015 and 2014, the Company had provided its counterparties with no collateral.

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

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

Derivative Instruments Designated as Cash Flow Hedges

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

To the extent a derivative instrument designated as a cash flow hedge is determined to be effective as a cash flow hedge of an exposure to changes in the fair value of a future transaction, the change in fair value of the derivative is deferred in accumulated other comprehensive income (loss), a component of partners’ capital in the consolidated balance sheets, until the underlying transaction hedged is recognized in the consolidated statements of operations. Ineffectiveness is inherent in the hedging of crude oil and fuel products. Due to the volatility in the markets for crude oil and fuel products, the Company is unable to predict the amount of ineffectiveness each period, determined on a derivative by derivative basis or in the aggregate for a specific commodity, and has the potential for the future loss of cash flow hedge accounting. Ineffectiveness has resulted, and the loss of cash flow hedge accounting has resulted, in increased volatility in the Company’s financial results. However, even though certain derivative instruments may not qualify for cash flow hedge accounting, the Company intends to continue to utilize such instruments as management believes such derivative instruments continue to provide the Company with the opportunity to more effectively stabilize cash flows.

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

Table of Contents
CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The Company recorded the following amounts in its consolidated balance sheets, consolidated statements of operations, consolidated statements of comprehensive income (loss) and consolidated statements of partners' capital as of, and for the years ended December 31, 2015 and 2014, related to its derivative instruments that were designated as cash flow hedges (in millions):

Type of Derivative	Amount of Gain (Loss) Recognized in Accumulated Other Comprehensive Income (Loss) on Derivatives (Effective Portion) Year Ended December 31, 2015	2014	Location of (Gain) Loss	Amount of Gain (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) into Net Loss (Effective Portion) Year Ended December 31, 2015	2014	Location of Gain (Loss)	Amount of Gain (Loss) Recognized in Net Loss on Derivatives (Ineffective Portion) Year Ended December 31, 2015	2014
Specialty products segment:								
Crude oil swaps	$—	$—	Cost of sales	$3.0	$1.8	Unrealized/Realized	$—	$—
Fuel products segment:								
Crude oil swaps	(5.6)	(185.8)	Cost of sales	(170.3)	44.2	Unrealized/Realized	(0.2)	4.8
Gasoline swaps	5.7	56.3	Sales	44.7	(1.4)	Unrealized/Realized	0.7	(7.6)
Diesel swaps	(8.8)	220.0	Sales	121.6	(6.7)	Unrealized/Realized	—	—
Jet fuel swaps	1.4	23.7	Sales	13.1	(0.9)	Unrealized/Realized	—	0.6
Total	$(7.3)	$114.2		$12.1	$37.0		$0.5	$(2.2)

The effective portion of the cash flow hedges classified in accumulated other comprehensive income (loss) was a gain of $6.4 million and a gain of $25.8 million as of December 31, 2015 and 2014, respectively. Absent a change in the fair market value of the underlying transactions, except for any underlying transactions pertaining to the payment of interest on existing financial instruments, the following other comprehensive gain at December 31, 2015, will be reclassified to earnings by December 31, 2016, with balances being recognized as follows (in millions):

Year	Accumulated Other Comprehensive Income
2016	$6.4
Total	$6.4

Derivative Instruments Designated as Fair Value Hedges

For derivative instruments that are designated and qualify as a fair value hedge (which are limited to interest rate swaps), the effective gain or loss on the derivative instrument, as well as the offsetting gain or loss on the hedged item attributable to the hedged risk are recognized as interest expense in the consolidated statements of operations. No hedge ineffectiveness was recognized as the interest rate swap qualifies for the "shortcut" method and, as a result, changes in the fair value of the derivative instrument offset the changes in the fair value of the underlying hedged debt. In addition, the differential to be paid or received on the interest rate swap arrangement is accrued and recognized as an adjustment to interest expense in the consolidated statements of operations. The Company assesses at

the inception of the fair value hedge whether the derivatives that are used in the hedging transactions are highly effective in offsetting changes in fair values of hedged items.
Fair value hedge accounting is discontinued when it is determined that a derivative no longer qualifies as an effective hedge or when it is no longer probable that the hedged forecasted transaction will occur. When fair value hedge accounting is discontinued because the derivative instrument no longer qualifies as effective fair value hedge, the derivative instrument is still subject to mark-to-market method of accounting, however the Company will cease to adjust the hedged asset or liability for changes in fair value.
In 2014, the Company entered into an interest rate swap agreement which converts a portion of the Company’s fixed rate debt to a floating rate. This agreement involves the receipt of fixed rate amounts in exchange for floating rate interest payments over the life of the agreement without an exchange of the underlying principal amount. Also, in connection with the interest rate swap agreement, the Company entered into an option that permits the counterparty to cancel the interest rate swap for a specified premium. The Company designated this interest rate swap and option as a fair value hedge. On January 13, 2015, the Company terminated its interest rate swap, which was designated as a fair value hedge, related to a notional amount of $200.0 million of 2022 Notes. In settlement of this swap, the Company recognized a net gain of approximately $3.3 million.

Table of Contents

CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The Company recorded the following gains (losses) in its consolidated statements of operations for the years ended December 31, 2015 and 2014 related to its derivative instrument designated as a fair value hedge (in millions):

	Location of Gain of Derivative	Amount of Gain Recognized in Net Loss Year Ended December 31, 2015	2014	Hedged Item	Location of Loss on Hedged Item	Amount of Loss Recognized in Net Loss Year Ended December 31, 2015	2014
Swaps not allocated to a specific segment:							
Interest rate swap	Interest expense	$0.5	$2.5	2022 Notes	Interest expense	$—	$(2.5)
Total		$0.5	$2.5			$—	$(2.5)

Derivative Instruments Not Designated as Hedges

For derivative instruments not designated as hedges, the change in fair value of the asset or liability for the period is recorded to unrealized gain (loss) on derivative instruments in the consolidated statements of operations. Upon the settlement of a derivative not designated as a hedge, the gain or loss at settlement is recorded to realized gain (loss) on derivative instruments in the consolidated statements of operations. The Company has entered into crude oil basis swaps that do not qualify as cash flow hedges for accounting purposes as they were not entered into simultaneously with a corresponding NYMEX WTI derivative contract. Additionally, the Company has entered into diesel crack spread collars, gasoline crack spread collars, natural gas collars, and certain other crude oil swaps, diesel swaps, gasoline swaps, natural gas swaps and platinum swaps that do not qualify as cash flow hedges for accounting purposes as they are determined not to be highly effective in offsetting changes in the cash flows associated with crude oil purchases and gasoline and diesel sales at the Company’s Superior refinery.

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

Type of Derivative	Amount of Gain (Loss) Recognized in Realized Gain (Loss) on Derivative Instruments Year Ended December 31, 2015	2014	Amount of Gain (Loss) Recognized in Unrealized Gain (Loss) on Derivative Instruments Year Ended December 31, 2015	2014
Specialty products segment:				
Natural gas swaps	$(10.7)	$1.1	$(2.5)	$(11.9)
Platinum swaps	(0.8)	—	0.1	(0.1)
Fuel products segment:				
Crude oil swaps	(67.6)	(48.5)	52.0	(61.9)
Crude oil basis swaps	1.1	5.7	(7.8)	0.1
Crude oil percentage basis swaps	(3.2)	—	0.2	—
Crude oil options	6.1	—	(0.3)	—
Gasoline swaps	(20.0)	(2.2)	(0.7)	10.1
Gasoline crack spread swaps	(5.5)	—	(4.3)	—
Gasoline crack spread collars	—	(0.4)	—	—
Diesel swaps	82.3	76.3	(68.7)	71.5
Diesel crack spread swaps	24.3	(3.6)	—	4.5
Diesel percentage basis crack spread swaps	(0.1)	—	(4.5)	—
Diesel crack spread collars	—	1.0	—	(0.1)
Jet fuel swaps	1.6	3.2	(1.6)	0.7
Jet fuel crack spread swaps	—	(0.1)	—	—

Natural gas swaps	—	—	(1.3)	—
Total	$7.5	$32.5	$(39.4)	$12.9

Table of Contents

Derivative Positions — Specialty Products Segment

Natural Gas Swap Contracts

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

Natural Gas Swap Contracts by Expiration Dates	MMBtu	$/MMBtu
First Quarter 2016	1,580,000	$4.24
Second Quarter 2016	1,380,000	$4.26
Third Quarter 2016	1,380,000	$4.26
Fourth Quarter 2016	1,540,000	$4.14
Calendar Year 2017	4,950,000	$3.85
Total	10,830,000	
Average price		$4.05

At December 31, 2014, the Company had the following derivatives related to natural gas purchases in its specialty products segment, none of which are designated as hedges:

Natural Gas Swap Contracts by Expiration Dates	MMBtu	$/MMBtu
First Quarter 2015	1,770,000	$4.09
Second Quarter 2015	1,500,000	$4.11
Third Quarter 2015	1,500,000	$4.11
Fourth Quarter 2015	1,900,000	$4.12
Calendar Year 2016	5,880,000	$4.22
Calendar Year 2017	1,830,000	$4.28
Total	14,380,000	
Average price		$4.18

Natural Gas Collars

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

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

Table of Contents
CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

At December 31, 2014, the Company had the following derivatives related to natural gas purchases in its specialty products segment, none of which are designated as hedges:

Natural Gas Collars by Expiration Dates	MMBtu	Average Bought Call ($/MMBtu)	Average Sold Put ($/MMBtu)
First Quarter 2015	240,000	$4.25	$3.79
Second Quarter 2015	240,000	$4.25	$3.79
Third Quarter 2015	240,000	$4.25	$3.79
Fourth Quarter 2015	200,000	$4.25	$3.85
Calendar Year 2016	600,000	$4.25	$3.89
Total	1,520,000		
Average price		$4.25	$3.84

Derivative Positions — Fuel Products Segment
Crude Oil Swap Contracts
At December 31, 2015, the Company had the following derivatives related to crude oil purchases in its fuel products segment, none of which are designated as hedges:

Crude Oil Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Swap ($/Bbl)
First Quarter 2016	29,120	320	$44.06
Second Quarter 2016	29,120	320	$44.06
Third Quarter 2016	29,440	320	$44.06
Fourth Quarter 2016	29,440	320	$44.06
Calendar Year 2017	630,720	1,728	$54.94
Total	747,840		
Average price			$53.24

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

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

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

Crude Oil Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Swap ($/Bbl)
First Quarter 2015	1,674,000	18,600	$89.55
Second Quarter 2015	91,000	1,000	$89.89
Third Quarter 2015	386,400	4,200	$69.20
Fourth Quarter 2015	386,400	4,200	$69.20
Calendar Year 2016	972,828	2,658	$78.02
Total	3,510,628		
Average price			$81.89

Table of Contents

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

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

Crude Oil Basis Swap Contracts

The Company has entered into crude oil basis swaps to mitigate the risk of future changes in pricing differentials between LLS and NYMEX WTI. At December 31, 2015, the Company had the following derivatives related to crude oil basis swaps in its fuel products segment, none of which are designated as hedges:

Crude Oil Basis Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Differential to NYMEX WTI ($/Bbl)
First Quarter 2016	182,000	2,000	$2.40
Second Quarter 2016	182,000	2,000	$2.40
Third Quarter 2016	184,000	2,000	$2.40
Fourth Quarter 2016	184,000	2,000	$2.40
Total	732,000		
Average differential			$2.40

The Company has entered into crude oil basis swaps to mitigate the risk of future changes in pricing differentials between WCS and NYMEX WTI. At December 31, 2015, the Company had the following derivatives related to crude oil basis swaps in its fuel products segment, none of which are designated as hedges:

Crude Oil Basis Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Differential to NYMEX WTI ($/Bbl)
First Quarter 2016	91,000	1,000	$(14.10)
Second Quarter 2016	91,000	1,000	$(14.10)
Third Quarter 2016	92,000	1,000	$(14.10)
Fourth Quarter 2016	92,000	1,000	$(14.10)
Calendar Year 2017	365,000	1,000	$(13.70)
Total	731,000		
Average differential			$(13.90)

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

Crude Oil Basis Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Differential to NYMEX WTI ($/Bbl)
First Quarter 2015	118,000	2,000	$(22.40)
Total	118,000		
Average differential			$(22.40)

Table of Contents
CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Crude Oil Percentage Basis Swap Contracts
The Company has entered into derivative instruments to secure a percentage differential on WCS crude oil to NYMEX WTI. At December 31, 2015, the Company had the following derivatives related to crude oil percentage basis swaps in its fuel products segment, none of which are designated as hedges:

Crude Oil Percentage Basis Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Fixed Percentage of NYMEX WTI (Average % of WTI/Bbl)	
First Quarter 2016	728,000	8,000	73.5	%
Second Quarter 2016	728,000	8,000	73.5	%
Third Quarter 2016	736,000	8,000	73.5	%
Fourth Quarter 2016	736,000	8,000	73.5	%
Calendar Year 2017	730,000	2,000	73.0	%
Total	3,658,000			
Average percentage			73.4	%

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

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

Crude Oil Option Contracts
During 2015, the Company entered into derivative instruments to mitigate the risk of future changes in the price of NYMEX WTI crude oil. At December 31, 2015, the Company had the following derivatives related to crude oil call option purchases in its fuel products segment, none of which are designated as hedges:

Crude Oil Option Contracts by Expiration Dates	Barrels Purchased	BPD	Average Bought Call ($/Bbl)
Fourth Quarter 2016	350,000	11,290	$ 55.00
Total	350,000		
Average price			$ 55.00

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

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

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

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

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

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

Gasoline Crack Spread Swap Contracts

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

Gasoline Crack Spread Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
First Quarter 2016	873,000	9,593	$8.98
Total	873,000		
Average price			$8.98

Diesel Swap Contracts

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

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

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

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

Table of Contents
CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Diesel Percentage Basis Crack Spread Swap Contracts

The Company has entered into derivative instruments to secure a fixed percentage of gross profit on diesel in excess of the floating value of NYMEX WTI crude oil. At December 31, 2014, the Company had the following diesel percentage basis crack spread swap contracts in its fuel products segment, none of which are designated as hedges:

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

Jet Fuel Swap Contracts

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

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

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

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

Natural Gas Swap Contracts

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

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

Platinum Swap Contracts

At December 31, 2014, the Company had approximately 1,900 troy ounces of platinum swap contracts through 2015 in its fuel products segment, none of which are designated as hedges.

9. Fair Value Measurements

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

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

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

Recurring Fair Value Measurements

Derivative Assets and Liabilities

Derivative instruments are reported in the accompanying consolidated financial statements at fair value. The Company's derivative instruments consist of over-the-counter ("OTC") contracts, which are not traded on a public exchange. Substantially all of the Company's derivative instruments are with counterparties that have long-term credit ratings of at least Baa1 and BBB+ by Moody's and S&P, respectively.

To estimate the fair values of the Company's commodity derivative instruments, the Company uses the forward rate, the strike price, contractual notional amounts, the risk free rate of return and contract maturity. To estimate the fair value of the Company's fixed-to-floating interest rate swap derivative instrument, the Company uses discounted cash flows, which use observable inputs such as maturity and market interest rates. Various analytical tests are performed to validate the counterparty data. The fair values of the Company's derivative instruments are adjusted for nonperformance risk and creditworthiness of the hedging entities through the Company's credit valuation adjustment ("CVA"). The CVA is calculated at the transaction level utilizing the fair value exposure at each payment date and applying a weighted probability of the appropriate survival and marginal default percentages. The Company uses the counterparty's marginal default rate and the Company's survival rate when the Company is in a net asset position at the payment date and uses the Company's marginal default rate and the counterparty's survival rate when the Company is in a net liability position at the payment date. As a result of applying the applicable CVA at December 31, 2015, the Company's net liability was reduced by approximately $1.2 million. As a result of applying the CVA at December 31, 2014, the Company's net asset was increased by approximately $2.0 million and net liability was reduced by approximately $0.1 million.

Observable inputs utilized to estimate the fair values of the Company's derivative instruments were based primarily on inputs that are readily available in public markets or can be derived from information available in publicly quoted markets. Based on the use of various unobservable inputs, principally non-performance risk, creditworthiness of the hedging entities and unobservable inputs in the forward rate, the Company has categorized these derivative instruments as Level 3. Significant increases (decreases) in any of those unobservable inputs in isolation would result in a significantly lower (higher) fair value measurement. The Company believes it has obtained the most accurate information available for the types of derivative instruments it holds. See Note 8 for further information on derivative instruments.

Pension Assets

Pension assets are reported at fair value in the accompanying consolidated financial statements. At December 31, 2015, the Company’s investments associated with its pension plan (as such term is hereinafter defined) primarily consisted of mutual funds. The mutual funds are categorized as Level 2 because inputs used in their valuation are not quoted prices in active markets that are indirectly observable and are valued at the NAV of shares in each fund held by the pension plan at quarter end as provided by the third party administrator. Plan investments can be redeemed within a short time frame (10 or so business days), if requested. See Note 12 for further information on pension assets.

Liability Awards

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

Renewable Identification Numbers Obligation

The Company's RINs Obligation represents a liability for the purchase of RINs to satisfy the EPA requirement to blend biofuels into the fuel products it produces pursuant to the EPA's Renewable Fuel Standard. RINs are assigned to biofuels produced in the U.S. as required by the EPA. The EPA sets annual quotas for the percentage of biofuels that must be blended into transportation fuels consumed in the U.S., and as a producer of motor fuels from petroleum, the Company is required to blend biofuels into the fuel products it produces at a rate that will meet the EPA's annual quota. To the extent the Company is unable to blend biofuels at that rate, it must purchase RINs in the open market to satisfy the annual requirement. The Company's RINs Obligation is based on the amount of RINs it must purchase net of amounts internally generated and the market price of those RINs as of the balance sheet date. The RINs Obligation is categorized as Level 2 and is measured at fair value using the market approach based on quoted prices from an independent pricing service.

In October 2014, the EPA granted the Company's Shreveport and San Antonio refineries a "small refinery exemption" under the RFS for the full year 2013, as provided for under the Clean Air Act. The EPA determined that for the full year 2013, compliance with the RFS would represent a "disproportionate economic hardship" for these two refineries. As a result of the exemption, the Company sold all excess RINs related to these refineries for a gain of $18.2 million, net of cost to generate, recorded in cost of sales for the year ended December 31, 2014, in the consolidated statements of operations.

For the years ended December 31, 2015 and 2014, the Company sold approximately 89 million RINs and 31 million RINS, respectively, for a gain of $55.4 million and $14.5 million, respectively, net of cost to generate, recorded in cost of sales in the consolidated statements of operations. As of December 31, 2015 and 2014, the Company had a RINs Obligation of approximately 125 million RINs and 87 million RINs, respectively, which resulted in RINs expense for the years ended December 31, 2015 and 2014, of approximately $94.2 million and $23.9 million, respectively.

Table of Contents
CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Hierarchy of Recurring Fair Value Measurements

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

	December 31, 2015				December 31, 2014			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Derivative assets:								
Crude oil swaps	$—	$—	$—	$—	$—	$—	$(89.8)	$(89.8)
Crude oil basis swaps	—	—	—	—	—	—	0.8	0.8
Crude oil percentage basis swaps	—	—	—	—	—	—	(0.2)	(0.2)
Gasoline swaps	—	—	—	—	—	—	13.5	13.5
Diesel swaps	—	—	—	—	—	—	97.0	97.0
Diesel crack spread swaps	—	—	—	—	—	—	4.5	4.5
Jet fuel swaps	—	—	—	—	—	—	2.7	2.7
Natural gas swaps	—	—	—	—	—	—	(7.2)	(7.2)
Natural gas collars	—	—	—	—	—	—	(0.5)	(0.5)
Platinum swaps	—	—	—	—	—	—	(0.1)	(0.1)
Interest rate swaps	—	—	—	—	—	—	2.5	2.5
Total derivative assets	—	—	—	—	—	—	23.2	23.2
Pension plan investments	0.4	47.1	—	47.5	0.2	49.4	—	49.6
Total recurring assets at fair value	$0.4	$47.1	$—	$47.5	$0.2	$49.4	$23.2	$72.8
Liabilities:								
Derivative liabilities:								
Crude oil swaps	$—	$—	$(5.2)	$(5.2)	$—	$—	$5.0	$5.0
Crude oil basis swaps	—	—	(0.3)	(0.3)	—	—	—	—
Crude oil percentage basis swaps	—	—	(6.7)	(6.7)	—	—	—	—
Crude oil options	—	—	(0.3)	(0.3)	—	—	—	—
Gasoline swaps	—	—	—	—	—	—	3.8	3.8
Gasoline crack spread swaps	—	—	(4.3)	(4.3)	—	—	—	—
Diesel swaps	—	—	—	—	—	—	(9.0)	(9.0)
Natural gas swaps	—	—	(16.2)	(16.2)	—	—	(4.9)	(4.9)
Natural gas collars	—	—	(0.9)	(0.9)	—	—	(0.5)	(0.5)
Total derivative liabilities	—	—	(33.9)	(33.9)	—	—	(5.6)	(5.6)
RINs Obligation	—	(88.4)	—	(88.4)	—	(16.3)	—	(16.3)
Liability Awards	—	—	—	—	(4.7)	—	—	(4.7)
Total recurring liabilities at fair value	$—	$(88.4)	$(33.9)	$(122.3)	$(4.7)	$(16.3)	$(5.6)	$(26.6)

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 years ended December 31, 2015 and 2014 (in millions):

	Derivative Instruments, Net For the Year Ended December 31,	
	2015	2014
Fair value at January 1,	$17.6	$(54.8)
Realized gain on derivative instruments	(8.1)	(43.8)
Unrealized loss on derivative instruments	(39.5)	(0.6)
Interest income, net	(0.5)	(0.8)
Change in fair value of cash flow hedges	(7.3)	114.2
Settlements	3.9	3.4
Transfers in (out) of Level 3	—	—
Fair value at December 31,	$(33.9)	$17.6
Total loss included in net loss attributable to changes in unrealized loss relating to financial assets and liabilities held as of December 31,	$(39.5)	$(0.6)

All settlements from derivative instruments designated as cash flow hedges and deemed "effective" are included in sales for gasoline, diesel and jet fuel derivatives, and cost of sales for crude oil derivatives in the consolidated statements of operations in the period that the hedged cash flow occurs. Any "ineffectiveness" associated with these settlements from derivative instruments designated as cash flow hedges are recorded in earnings in realized gain (loss) on derivative instruments in the consolidated statements of operations. All settlements from derivative instruments designated as fair value hedges are accrued and recorded as an adjustment to interest expense in the consolidated statements of operations. All settlements from derivative instruments not designated as hedges are recorded in realized gain (loss) on derivative instruments in the consolidated statements of operations. See Note 8 for further information on derivative instruments.

Nonrecurring Fair Value Measurements

Certain nonfinancial assets and liabilities are measured at fair value on a nonrecurring basis and are subject to fair value adjustments in certain circumstances, such as when there is evidence of impairment. Assets and liabilities acquired in business combinations are recorded at their fair value as of the date of acquisition.

The Company reviews for goodwill impairment annually on October 1 and whenever events or changes in circumstances indicate its carrying value may not be recoverable. The fair value of the reporting units is determined using the income approach. The income approach focuses on the income-producing capability of an asset, measuring the current value of the asset by calculating the present value of its future economic benefits such as cash earnings, cost savings, corporate tax structure and product offerings. Value indications are developed by discounting expected cash flows to their present value at a rate of return that incorporates the risk-free rate for the use of funds, the expected rate of inflation and risks associated with the reporting unit. These assets would generally be classified within Level 3, in the event that the Company were required to measure and record such assets at fair value within its consolidated financial statements.

The Company periodically evaluates the carrying value of long-lived assets to be held and used, including indefinite-lived intangible assets and property plant and equipment, when events or circumstances warrant such a review. Fair value is determined primarily using anticipated cash flows assumed by a market participant discounted at a rate commensurate with the risk involved and these assets would generally be classified within Level 3, in the event that the Company was required to measure and record such assets at fair value within its consolidated financial statements.

Estimated Fair Value of Financial Instruments

Cash

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

Debt

The estimated aggregate fair value of the Company's senior notes defined as Level 1 was based upon quoted market prices in an active market. The estimated aggregate fair value of the Company's senior notes classified as Level 2 was based upon directly observable inputs. The carrying value of borrowings, if any, under the Company's revolving credit facility and capital lease obligations approximate their fair values as determined by discounted cash flows and are classified as Level 3. The carrying value of the related party note payable approximates its fair value due to the short-term maturity of this financial instrument. See Note 7 for further information on long-term debt.

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

		December 31, 2015		December 31, 2014	
	Level	Fair Value	Carrying Value	Fair Value	Carrying Value
Financial Instrument:					
Senior notes	1	$1,095.8	$ 1,230.8	$630.0	$ 606.6
Senior notes	2	$294.1	$ 317.6	$803.3	$ 885.3
Revolving credit facility	3	$105.1	$ 105.1	$143.3	$ 143.3
Note payable - related party	3	$73.5	$ 73.5	$—	$ —
Capital lease and other obligations	3	$46.4	$ 46.4	$43.6	$ 43.6

10. Partners' Capital

Units Outstanding

Of the 75,884,400 common units outstanding at December 31, 2015, 59,623,920 common units were held by the public, with the remaining 16,260,480 common units held by the Company's affiliates.

Significant information regarding rights of the limited partners includes the following:

- Rights to receive distributions of available cash within 45 days after the end of each quarter, to the extent the Company has sufficient cash from operations after the establishment of cash reserves.
- Limited partners have limited voting rights on matters affecting the Company's business. The general partner may consider only the interests and factors that it desires and has no duty or obligation to give any consideration of any interests of the Company's limited partners. Limited partners have no right to elect the board of directors of the Company's general partner.
- The vote of the holders of at least 66 2/3% of all outstanding units voting together as a single class is required to remove the general partner. Any holder, other than the general partner or the general partner's affiliates, that owns 20% or more of any class of units outstanding cannot vote on any matter.
- The Company may issue an unlimited number of limited partner interests without the approval of the limited partners.
- Limited partners may be required to sell their units to the general partner if at any time the general partner owns more than 80% of the issued and outstanding common units.

Distributions and Incentive Distribution Rights

The Company's general partner is entitled to incentive distributions if the amount it distributes to unitholders with respect to any quarter exceeds specified target levels shown below:

	Total Quarterly Distribution Per Common Unit Target Amount	Marginal Percentage Interest in Distributions	
		Unitholders	General Partner
Minimum Quarterly Distribution	$0.45	98 %	2 %
First Target Distribution	up to $0.495	98 %	2 %
Second Target Distribution	above $0.495 up to $0.563	85 %	15 %
Third Target Distribution	above $0.563 up to $0.675	75 %	25 %
Thereafter	above $0.675	50 %	50 %

The Company's ability to make distributions is limited by its debt instruments. The revolving credit facility generally permits the Company to make cash distributions to unitholders as long as immediately after giving effect to such a cash distribution the Company has availability under the revolving credit facility at least the greater of (i) 15% of the Borrowing Base (as defined in the credit agreement) then in effect and (ii) $70.0 million. Further, the revolving credit facility contains one springing financial covenant which provides that only if the Company's availability under the revolving credit facility falls below the greater of

133

CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(a) 12.5% of the Borrowing Base (as defined in the credit agreement) then in effect and (b) $45.0 million, the Company 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. The indentures governing the 2021 Notes, 2022 Notes and 2023 Notes provide that if the Company's fixed charge coverage ratio (as defined in the indentures) for the most recently ended four full fiscal quarters is not less than 1.75 to 1.0, the Company will be permitted to pay distributions to its unitholders in an amount equal to available cash from operating surplus (each as defined in the Company's partnership agreement) with respect to its preceding fiscal quarter, subject to certain customary adjustments described in the indentures. If the Company's fixed charge coverage ratio is less than 1.75 to 1.0, the Company will be able to pay distributions to its unitholders up to an amount equal to (i) a $225.0 million basket for the 2021 Notes, (ii) a $210.0 million basket for the 2022 Notes and (iii) a $225.0 million basket for the 2023 Notes, subject to certain customary adjustments described in the indentures.

The Company's distribution policy is as defined in its partnership agreement. For the years ended December 31, 2015, 2014 and 2013, the Company made distributions of $224.6 million, $210.2 million and $201.6 million, respectively, to its partners. For the years ended December 31, 2015, 2014 and 2013, the general partner was allocated $16.8 million, $15.4 million and $14.7 million, respectively, in incentive distribution rights.

Public Offerings of Common Units

During 2015, 2014 and 2013, the Company completed the following marketed public offerings of its common units (in millions except unit and per unit data):

Closing Date	Number of Common Units Offered		Price per Unit	Net Proceeds [1]	General Partner Contribution [2]	Underwriting Discount	Use of Proceeds
January 8, 2013	5,750,000	[3]	$31.81	$175.2	$3.8	$ 7.4	Net proceeds were used to repay borrowings under the revolving credit facility and for general partnership purposes.
April 1, 2013	6,037,500	[4]	$37.50	$217.3	$4.6	$ 9.1	Net proceeds were used for general partnership purposes.
March 13, 2015	6,000,000		$26.75	$153.9	$3.3	$ 6.4	Net proceeds were used to redeem a portion of the 2020 Notes and to repay borrowings under the revolving credit facility.

(1) Proceeds are net of underwriting discounts, commissions and expenses but before the general partner's capital contribution.
(2) The Company's general partner contributions were made to retain its 2% general partner interest.
(3) Includes the full exercise of the overallotment option of 750,000 common units which closed concurrently with the 5,000,000 firm units on January 8, 2013.
(4) Includes the full exercise of the overallotment option of 787,500 common units which closed on April 4, 2013.

On March 10, 2014, the Company entered into an Equity Placement Agreement with various sales agents under which the Company may issue and sell, from time to time, common units representing limited partner interests, having an aggregate offering price of up to $300.0 million through one or more sales agents. The Equity Placement Agreement provides the Company the right, but not the obligation, to sell common units in the future, at prices the Company deems appropriate. These sales, if any, will be made pursuant to the terms of the Equity Placement Agreement between the Company and the sales agents. The net proceeds from any sales under this agreement will be used for general partnership purposes, which may include, among other things, repayment of indebtedness, working capital, capital expenditures and acquisitions. The Company's general partner contributed its proportionate capital contribution to retain its 2% general partner interest. For the years ended December 31, 2015 and 2014, the Company sold 432,167 and 134,955, respectively, common units under the Equity Placement Agreement for net proceeds of $10.2 million and $3.6 million, respectively. Underwriting discounts for 2015 and 2014 totaled $0.1 million and $0.1 million, respectively, and the Company's general partner contributed $0.2 million and $0.1 million, respectively, to maintain its general partner interest.

11. Unit-Based Compensation

The Company's general partner originally adopted a Long-Term Incentive Plan on January 24, 2006, which was amended and restated effective December 10, 2015 ("LTIP"), for its employees, consultants and directors and its affiliates who perform services for the Company. The LTIP provides for the grant of restricted units, phantom units, unit options and substitute awards and, with respect to unit options and phantom units, the grant of distribution equivalent rights ("DERs"). Subject to adjustment for certain events, an aggregate of 3,883,960 common units may be delivered pursuant to awards under the LTIP. Units withheld to satisfy the Company's general partner's tax withholding obligations are available for delivery pursuant to other awards. The LTIP is administered by the compensation committee of the Company's general partner's board of directors.

Non-employee directors of the Company's general partner have been granted phantom units under the terms of the LTIP as part of their director compensation package related to fiscal years 2013 and 2014. These phantom units have a four year service period with one-quarter of the phantom units vesting annually on each December 31 of the vesting period. Although ownership of common units related to the vesting of such phantom units does not transfer to the recipients until the phantom units vest. In addition, the recipients have DERs on these phantom units from the date of grant.

For the years ended December 31, 2015 and 2014, named executive officers and certain employees were awarded phantom units under the terms of the LTIP, as part of the Company's achievement of specified levels of financial performance in the fiscal year. These phantom units are subject to time-vesting requirements whereby 25% of the units vest during the performance period, and the remainder will vest ratably over the next three years on each December 31. Although ownership of common units related to the vesting of such phantom units does not transfer to the recipients until the phantom units vest, the recipients have DERs on these phantom units from the date of grant.

The Company uses the market price of its common units on the grant date to calculate the fair value and related compensation cost of the phantom units. The Company amortizes this compensation cost to partners' capital and general and administrative expense in the consolidated statements of operations using the straight-line method over the service period, as it expects these units to fully vest.

Liability Awards are awards that are expected to be settled in cash on their vesting dates, rather than in equity units. Phantom unit Liability Awards are recorded in accrued salaries, wages and benefits in the consolidated balance sheets based on the vested portion of the fair value of the awards on the balance sheet date. The fair value of Liability Awards are updated at each balance sheet date and changes in the fair values of the vested portions of the awards are recorded as increases or decreases to compensation expense within general and administrative expense in the consolidated statements of operations. As a result of the amendment and restatement of the LTIP on December 10, 2015, all Liability Awards were modified to value the awards based upon the closing unit price on that date. This modification did not affect the remaining service period.

A summary of the Company's non-vested phantom units as of December 31, 2015, and the changes during the years ended December 31, 2015, 2014 and 2013, are presented below:

	Number of Phantom Units	Weighted-Average Grant Date Fair Value
Non-vested at January 1, 2013	835,927	$27.57
Granted	483,044	27.73
Vested	(276,115)	24.22
Forfeited	(354,600)	30.60
Non-vested at December 31, 2013	688,256	$23.70
Granted	477,527	25.97
Vested	(280,263)	23.72

Forfeited	(383,400)	25.59
Non-vested at December 31, 2014	502,120	$26.48
Granted	343,533	21.70
Vested	(321,741)	23.54
Forfeited	(103,188)	23.94
Non-vested at December 31, 2015	420,724	$24.27

For the years ended December 31, 2015, 2014 and 2013, compensation expense of $7.5 million, $5.5 million and $4.8 million, respectively, was recognized in the consolidated statements of operations related to vested phantom unit grants, including

$5.0 million, $2.5 million and $1.6 million, attributable to Liability Awards for the years ended December 31, 2015, 2014 and 2013, respectively. As of December 31, 2015 and 2014, there was a total of $9.6 million and $12.2 million, respectively of unrecognized compensation costs related to nonvested phantom unit grants, including $10.5 million, attributable to Liability Awards for the year ended December 31, 2014. These costs are expected to be recognized over a weighted-average period of approximately 3 years. The total fair value of phantom units vested during the years ended December 31, 2015, 2014 and 2013, was $7.0 million, $6.7 million and $6.7 million, respectively.

12. Employee Benefit Plans

Defined Contribution Plan

The Company has a domestic defined contribution plan administered by its general partner for (i) all full-time employees that are eligible to participate in the plan ("401(k) Plan"). Participants in the 401(k) Plan are allowed to contribute 1% to 70% of their pre-tax earnings to the plan, subject to government imposed limitations. The Company matches 100% of each 1% of eligible compensation contributed by the participant up to 4% and 50% of each additional 1% of eligible compensation contributed up to 6%, for a maximum contribution by the Company of 5% of eligible compensation contributed per participant. The plan also includes a profit-sharing component for eligible employees. Contributions under the profit-sharing component are determined by the board of directors of the Company's general partner and are discretionary. The funding policy is consistent with funding requirements of applicable laws and regulations.

The Company recorded the following 401(k) Plan matching contribution and profit sharing expenses in the consolidated statement of operations for the years ended December 31, 2015, 2014 and 2013 (in millions):

	Year Ended December 31,		
	2015	2014	2013
401(k) Plan matching contribution expense	$5.9	$5.4	$4.1
Profit sharing expense	$—	$1.2	$0.9

Defined Benefit Pension Plan

The Company has domestic noncontributory defined benefit plans for those 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"), (ii) were formerly employees of Murphy Oil Corporation ("Murphy Oil") represented by the IUOE and who became employees of the Company as a result of the acquisition of the Superior refinery on September 30, 2011 (the "Superior Pension Plan") or (iii) were formerly employees of Montana Refining and who became employees of the Company as a result of the Montana Acquisition on October 1, 2012 (the "Montana Pension Plan" and together with the Penreco Pension Plan and the Superior Pension Plan, the "Pension Plan"). During 2015, the Company made contributions of $1.5 million to its Pension Plan and expects to make contributions in 2016 of approximately $1.9 million to its Pension Plan.

Under the Penreco Pension Plan, benefits are based primarily on years of service for USW and IUOE represented employees and the employee's final 60 months' average compensation for salaried employees. In 2009, the Company amended the Penreco Pension Plan, which curtailed Penreco employees from accumulating additional benefits subsequent to December 31, 2009.

Under the Superior Pension Plan, benefits are based primarily on years of service for IUOE represented employees and the employee's three highest consecutive calendar years of compensation within the last 10 years of service. Effective July 1, 2012, the Company amended the Superior Pension Plan, which curtailed Superior employees from accumulating additional benefits subsequent to December 31, 2012.

Under the Montana Pension Plan, benefits are based primarily on years of service and the employees' 36 months' highest average compensation for salaried employees. Effective October 1, 2012, the date of the Montana Acquisition, the Company amended the Montana Pension Plan, which curtailed only the Montana salaried employees from accumulating additional benefits subsequent to October 31, 2012. Effective August 31, 2015, the Company again amended the Montana Pension Plan, which curtailed the collective bargaining employees from accumulating additional benefits subsequent to December 31, 2015. As a result, the Company recorded a $0.9 million curtailment gain for the year ended December 31, 2015.

Defined Benefit Other Plans

The Company also has domestic contributory defined benefit post-retirement medical plans and contributory life insurance plans for (i) those 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 and who became employees of the Company as a result of the acquisition of the Superior refinery on September 30, 2011 ("Superior Other Plan" and together with the Penreco Other Plan, the "Other Plan"). The funding policy is consistent with funding requirements of applicable laws and regulations.

Effective 2009, the Company amended the Penreco Other Plan, which curtailed employees from accumulating additional benefits subsequent to February 28, 2009. Effective July 1, 2012, the Company amended the Superior Other Plan, which curtailed Superior employees from accumulating additional benefits subsequent to December 31, 2012.

The long-term accrued benefit obligation recognized in the consolidated balance sheets for the Penreco Other Plan was $0.2 million and $0.3 million as of December 31, 2015 and 2014, respectively. In addition, other post-retirement benefit income related to this plan was $0.4 million for 2015. There was no other post-retirement benefit income (cost) related to this plan for 2014.

All information presented below has been adjusted for these curtailments for the Pension Plan. The change in the benefit obligations, change in the plan assets, funded status and amounts recognized in the consolidated balance sheets were as follows (in millions):

	Year Ended December 31,	
	2015	2014
	Pension Plan	
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$69.3	$57.2
Service cost	0.5	0.4
Interest cost	2.6	2.6
Plan curtailment	(0.9)	—
Benefits paid	(2.6)	(2.5)
Actuarial (gain) loss	(8.6)	11.7
Administrative expense	—	(0.1)
Benefit obligation at end of year	$60.3	$69.3
Change in plan assets:		
Fair value of plan assets at beginning of year	$49.6	$45.8
Benefit payments	(2.6)	(2.5)
Actual return on assets	(1.0)	4.9
Administrative expense	—	(0.1)
Employer contribution	1.5	1.5
Fair value of plan assets at end of year	$47.5	$49.6
Funded status — benefit obligation in excess of plan assets	$(12.8)	$(19.7)
Reconciliation of amounts recognized in the consolidated balance sheets:		
Accrued benefit obligation, long-term	$(12.8)	$(19.7)
Unrecognized net actuarial loss	6.8	11.9
Accumulated other comprehensive loss	6.8	11.9
Net amount recognized at end of year	$(6.0)	$(7.8)

The accumulated benefit obligation for the Pension Plan was $60.3 million and $68.4 million as of December 31, 2015 and 2014, respectively. Selected information for the Company's pension plans with an accumulated benefit obligation in excess of plan assets were as follows (in millions):

	Year Ended December 31,	
	2015	2014
Accumulated benefit obligation	$60.3	$68.4

Fair value of plan assets	$47.5	$49.6

Selected information for the Company’s Pension Plan with projected benefit obligation in excess of plan assets were as follows (in millions):

	Year Ended December 31, 2015	2014
Projected benefit obligation	$60.3	$69.3
Fair value of plan assets	$47.5	$49.6

The components of net periodic pension cost (income) for 2015, 2014 and 2013 were as follows (in millions):

	Pension Plan Year Ended December 31, 2015	2014	2013
Service cost	$0.5	$0.4	$0.4
Interest cost	2.6	2.6	2.4
Expected return on assets	(3.3)	(3.1)	(2.9)
Amortization of net loss	0.8	0.3	0.8
Curtailment gain recognized	(0.9)	—	—
Net periodic benefit cost (income)	$(0.3)	$0.2	$0.7

The components of changes recognized in other comprehensive (income) loss for the Pension Plan for 2015, 2014 and 2013 were as follows (in millions):

	Pension Plan Year Ended December 31, 2015	2014	2013
Changes in plan assets and benefit obligations recognized in other comprehensive (income) loss:			
Net (gain) loss	$(4.3)	$9.9	$(8.8)
Amounts recognized as a component of net periodic benefit cost:			
Amortization or settlement recognition of net loss	(0.8)	(0.3)	(0.8)
Total recognized in other comprehensive (income) loss	$(5.1)	$9.6	$(9.6)

The portion relating to the Pension Plan classified in accumulated other comprehensive income (loss) includes losses of $6.8 million and $11.9 million as of December 31, 2015 and 2014, respectively. In 2016, the estimated amount that will be amortized from accumulated other comprehensive income (loss) includes a net loss of $0.4 million for the Pension Plan.

For the Pension Plan, the Company uses a corridor approach to amortize actuarial gains and losses. Under this approach, net actuarial gains or losses in excess of ten percent of the larger of the projected benefit obligation or the fair value of plan assets are amortized on a straight-line basis. The period of amortization is the average remaining service of active participants who are expected to receive benefits under the plans.

All pension plans have a December 31 measurement date. The significant weighted average assumptions used to determine the benefit obligations for the years ended December 31, 2015 and 2014, were as follows:

	Benefit Obligations Assumptions 2015	2014
Pension Plan:		
Discount rate for Penreco Pension Plan	4.30%	3.92%
Discount rate for Superior Pension Plan	4.27%	3.86%
Discount rate for Montana Pension Plan	4.21%	4.13%

Rate of compensation increase for Montana Pension Plan	N/A	3.00	%

138

Table of Contents
CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The significant weighted average assumptions used to determine the net periodic benefit cost (income) for the years ended December 31, 2015, 2014 and 2013 were as follows:

	Net Periodic Benefit Cost (Income) Assumptions					
	2015		2014		2013	
Pension Plan:						
Discount rate for Penreco Pension Plan	3.92	%	4.78	%	3.86	%
Discount rate for Superior Pension Plan	3.86	%	4.66	%	3.75	%
Discount rate for Montana Pension Plan	4.13	%	4.97	%	4.03	%
Expected return on plan assets for Penreco Pension Plan (1)	6.75	%	6.75	%	6.75	%
Expected return on plan assets for Superior Pension Plan (1)	6.75	%	6.75	%	6.75	%
Expected return on plan assets for Montana Pension Plan (1)	6.75	%	6.75	%	6.75	%
Rate of compensation increase for Montana Pension Plan	3.00	%	3.00	%	3.00	%

(1) The Company considered the historical returns, the future expectation for returns for each asset class and fair value of the plan assets, as well as the target asset allocation of the Pension Plan portfolio which was developed in accordance with the Company’s Statement of Investment Policy, to develop the expected long-term rate of return on plan assets.

Investment Policy

The Defined Benefit Plan Investment Committee (the “Investment Committee”) is responsible for the overall management of the Pension Plan assets, and its responsibilities encompass establishing the investment strategies and policies, monitoring the management of plan assets, reviewing the asset allocation mix on a regular basis, monitoring the performance of the Pension Plan assets to determine whether the investments objectives are met and guidelines followed and taking the appropriate action if objectives are not followed. The Company uses different investment managers with various asset management objectives to eliminate any significant concentration of risk. The Investment Committee believes there are no significant concentrations of risks associated with the investment assets. The Company’s investment manager will assist in the continual assessment of assets and the potential reallocation of certain investments and will evaluate the selection of investment managers for the Pension Plan assets based on such factors as organizational stability, depth of resources, experience, investment strategy and process, performance expectations and fees.

Long-term strategic investment objectives utilize a diversified mix of equity and fixed income securities to preserve the funded status of the trusts, and balance risk and return in relationship to the respective liabilities. The primary investment strategy currently employed is a dynamic de-risking strategy that periodically rebalances among various investment categories depending on the current funded position and maximizes the effectiveness of the Pension Plan asset allocation strategy. This program is designed to actively move from return-seeking investments (such as equities) toward liability-hedging investments (such as fixed income) as funding levels improve.

Effective June 2013, all of the Pension Plan assets were invested in a Master Trust. Trust assets in the Pension Plan are invested subject to the policy restriction that the average quality of the fixed income portfolio must be rated at least investment grade by both Moody’s and S&P. These assets are invested in accordance with prudent expert standards as mandated by the Employee Retirement Income Security Act (“ERISA”). The Pension Plan’s target asset allocation is currently comprised of the following:

Asset Class	Range of Asset Allocation	Target Allocation
Domestic equities	15–25%	20%
Foreign equities	15–25%	20%

Fixed income	55–65%	60%

Investment Fund Strategies

Domestic equity funds include funds that invest in U.S. common and preferred stocks. Foreign equity funds invest in securities issued by companies listed on international stock exchanges. Certain funds have value and growth objectives and managers may

139

Table of Contents

attempt to profit from security mispricing in equity markets to meet these objectives. Short term investments (including commercial paper, certificates of deposits and government repurchase agreements) and derivatives may be used for hedging purposes to limit exposure to various risk factors.

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

The Company's Pension Plan asset allocations, as of December 31, 2015 and 2014, by asset category, are as follows:

	2015		2014	
Cash and cash equivalents	1	%	—	%
Domestic equities	20	%	20	%
Foreign equities	19	%	19	%
Fixed income	60	%	61	%
	100	%	100	%

At December 31, 2015, the Company's investments associated with its Pension Plan (as such term is hereinafter defined) primarily consisted of (i) cash and cash equivalents and (ii) mutual funds. The mutual funds are categorized as Level 2 because inputs used in their valuation are not quoted prices in active markets that are indirectly observable and are valued at the net asset value ("NAV") of shares in each fund held by the Pension Plan at quarter end as provided by the third party administrator. See Note 9 for the definition of Levels 1, 2 and 3. The Company's Pension Plan assets measured at fair value at December 31, 2015 and 2014, were as follows (in millions):

	Fair Value of Pension Assets at December 31,			
	2015		2014	
	Level 1	Level 2	Level 1	Level 2
Cash and cash equivalents	$0.4	$—	$0.2	$—
Domestic equities	—	9.6	—	10.0
Foreign equities	—	9.2	—	9.4
Fixed income	—	28.3	—	30.0
	$0.4	$47.1	$0.2	$49.4

The following benefit payments for the Pension Plan, which reflect expected future service, as appropriate, are expected to be paid in the years indicated as of December 31, 2015 (in millions):

	Pension Benefits
2016	$2.8
2017	3.0
2018	3.0
2019	3.1
2020	3.3
2021 to 2025	17.6
Total	$32.8

Table of Contents
CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

13. Accumulated Other Comprehensive Loss

The table below sets forth a summary of changes in accumulated other comprehensive income (loss) by component for the year ended December 31, 2015 and 2014 (in millions):

	Derivatives	Defined Benefit Pension And Retiree Health Benefit Plans	Foreign Currency Translation Adjustment	Total
Accumulated other comprehensive loss at December 31, 2013	$(51.4)	$(1.9)	$(0.1)	$(53.4)
Other comprehensive income (loss) before reclassifications	114.2	(9.9)	(0.5)	103.8
Amounts reclassified from accumulated other comprehensive loss	(37.0)	0.3	—	(36.7)
Net current period other comprehensive income (loss)	77.2	(9.6)	(0.5)	67.1
Accumulated other comprehensive income (loss) at December 31, 2014	25.8	(11.5)	(0.6)	13.7
Other comprehensive income (loss) before reclassifications	(7.3)	4.3	(0.6)	(3.6)
Amounts reclassified from accumulated other comprehensive income (loss)	(12.1)	0.4	—	(11.7)
Net current period other comprehensive income (loss)	(19.4)	4.7	(0.6)	(15.3)
Accumulated other comprehensive income (loss) at December 31, 2015	$6.4	$(6.8)	$(1.2)	$(1.6)

The table below sets forth a summary of reclassification adjustments out of accumulated other comprehensive income (loss) in the Company's consolidated statements of operations for the years ended December 31, 2015 and 2014, (in millions):

Components of Accumulated Other Comprehensive Income (Loss)	2015	2014	Location of Gain (Loss)
Derivative gains (losses) reflected in gross profit			
	$179.4	$(9.0)	Sales
	(167.3)	46.0	Cost of sales
	$12.1	$37.0	Total
Amortization of defined benefit pension benefit plans:			
Amortization of net loss	$(0.8)	$(0.3)	(1)
	$(0.8)	$(0.3)	Total

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

14. Income Taxes

The Company conducts certain activities through wholly-owned subsidiaries that are corporations which in certain circumstances are subject to federal, state and local income taxes. On December 31, 2015, ADF Holdings, Inc. converted to ADF Holdings, LLC and Anchor Drilling Fluids USA, Inc. converted to Anchor Drilling Fluids USA, LLC. Both ADF Holdings, LLC and Anchor Drilling Fluids USA, LLC have elected to be treated as pass-through entities for tax purposes. As a result, the activities of Anchor will be included in the earnings of the Company going forward and generally the Company will not be subject to federal and state income taxes. As of December 31, 2015, 2014 and 2013, the components of federal and state income tax expense are summarized as follows (in millions):

	December 31,		
	2015	2014	2013
Current expense:			
Federal	$0.1	$0.2	$—
State	—	0.2	0.4
Total	$0.1	$0.4	$0.4
Deferred expense (benefit):			
Federal	$(26.5)	$(1.5)	$—
State	(2.0)	0.3	—
Total	$(28.5)	$(1.2)	$—
Total income tax expense (benefit)	$(28.4)	$(0.8)	$0.4

A reconciliation of effective tax rate to the U.S. statutory rate attributable to operations for December 31, 2015, 2014 and 2013 is as follows:

	December 31,		
	2015	2014	2013
Federal income tax rate	35.0%	35.0%	35.0%
Partnership earnings not subject to tax	(13.8)%	(22.4)%	(35.0)%
State income taxes, net of federal income tax effect	0.6%	(0.4)%	11.4%
State tax rate change	0.2%	—%	—%
Impact of non-deductible goodwill	(5.0)%	(11.5)%	—%
Anchor LLC conversions	0.3%	—%	—%
Other items, net	(0.4)%	—%	(1.1)%
Effective tax rate	16.9%	0.7%	10.3%

Deferred Taxes

Deferred taxes result from the temporary differences between financial reporting carrying amounts and the tax basis of existing assets and liabilities. The table below summarizes the principal components of the deferred tax assets (liabilities) as follows as of December 31, 2015 and 2014 (in millions):

	December 31, 2015	2014
Deferred income tax assets:		
Inventory	$—	$2.3
Net operating loss carryforwards	0.8	3.7
Total deferred income tax assets	$0.8	$6.0
Deferred income tax liabilities:		
Intangible assets	$(0.1)	$(22.0)
Unrealized gains	(0.5)	—
Property, plant and equipment	(2.0)	(14.0)
Total deferred income tax liabilities	$(2.6)	$(36.0)
Net deferred income tax liability	$(1.8)	$(30.0)

As a result of the Company's analysis, management has determined that the Company does not have any uncertain tax positions. As of December 31, 2015, the Company had tax loss carryforwards of approximately $2.1 million, which are expected to be utilized prior to expiration in 2035. As of December 31, 2015, the Company had $0.8 million deferred tax assets arising from net operating loss carryforwards. The Company's federal and state tax returns remain subject to examination by taxing authorities for three years.

15. Earnings per Unit

The following table sets forth the computation of basic and diluted earnings per limited partner unit for the years ended December 31, 2015, 2014 and 2013 (in millions, except unit and per unit data):

	Year Ended December 31, 2015	2014	2013
Numerator for basic and diluted earnings per limited partner unit:			
Net income (loss)	$(139.4)	$(112.2)	$3.5
Less:			
General partner's interest in net income (loss)	(2.8)	(2.2)	0.1
General partner's incentive distribution rights	16.8	15.4	14.7
Non-vested share based payments	—	—	0.2
Net loss available to limited partners	$(153.4)	$(125.4)	$(11.5)
Denominator for basic and diluted earnings per limited partner unit:			
Basic weighted average limited partner units outstanding	74,896,096	69,671,827	67,938,784
Diluted weighted average limited partner units outstanding (1)	74,896,096	69,671,827	67,938,784
Limited partners' interest basic and diluted net loss per unit	$(2.05)	$(1.80)	$(0.17)

(1) Total diluted weighted average limited partner units outstanding excludes 0.4 million, 0.2 million and 0.2 million potentially dilutive phantom units for the years ended December 31, 2015, 2014 and 2013, respectively.

16. Transactions with Related Parties

During the years ended December 31, 2015, 2014 and 2013, the Company had product sales to related parties owned by a limited partner, excluding the transactions discussed below, of $12.0 million, $9.1 million and $9.7 million, respectively. Trade accounts and other receivables from related parties at December 31, 2015 and 2014 were $0.4 million and $1.2 million, respectively. The Company also had purchases from related parties owned by a limited partner, excluding transactions discussed below, during the years ended December 31, 2015, 2014 and 2013 of $21.8 million, $41.1 million and $9.0 million, respectively. Accounts payable to related parties, excluding accounts payable related to the transactions discussed below, at December 31, 2015 and 2014, were $2.3 million and $4.3 million, respectively.

The Company has a crude oil supply agreement with Legacy Resources, the Master Crude Oil Purchase and Sale Agreement. Legacy Resources is owned in part by one of the Company's general partners, the Company's executive vice chairman of the board of the Company's general partner, F. William Grube. No crude oil is currently being purchased by the Company under this agreement. During the year ended December 31, 2015, the Company had no crude oil purchases from Legacy Resources. During the years ended December 31, 2014 and 2013, the Company had crude oil purchases of $0.8 million and $1.2 million, respectively, from Legacy Resources under spot agreements. The Company had no accounts payable to Legacy Resources at December 31, 2015 and December 31, 2014.

Nicholas J. Rutigliano, a former member of the board of directors of the Company's general partner who retired in September 2014, founded Tobias Insurance Group, Inc. ("Tobias"), a commercial insurance brokerage business, which was acquired by Assured Partners, LLC. Mr. Rutigliano continues to serve as president of Tobias. Tobias has historically placed the Company's directors' and officers' liability insurance. There were no premiums paid to Tobias for the year ended December 31, 2015. The total premiums paid to Tobias by the Company for the years ended December 31, 2014 and 2013, were $0.7 million and $0.7 million, respectively. With the exception of its directors' and officers' liability insurance which were placed with this commercial insurance brokerage company, the Company placed its insurance requirements with third parties during the years ended December 31, 2015, 2014 and 2013.

The Company has a general services master services agreement with a third party construction company related to the Montana refinery expansion project in which various construction related services were performed during 2015 and 2014. This third party is related to refinery management. For the years ended December 31, 2015, 2014 and 2013, the Company had capital expenditures of $43.0 million, $29.0 million and $6.3 million, respectively, for construction related services. Accounts payable under this contract at December 31, 2015 and 2014, were $10.0 million and $2.6 million, respectively.

During 2015, the Company entered into an agreement for logistic administration/support, general administrative management and fiscal administration services with Monument Chemicals, Inc. ("Monument Chemical"). Monument Chemical is owned by a limited partner and a member of the board of the Company's general partner is a member of Monument Chemical's management. Under this agreement, Monument Chemical rents storage tanks in Belgium on the Company's behalf and organizes delivery of products to the Company's customers. A commission is paid to Monument Chemical based on the sales value invoiced to the Company's customers. For the year ended December 31, 2015, the Company paid total commissions and general administrative fees of $0.5 million. Accounts payable under this contract at December 31, 2015 were immaterial.

During the year ended December 31, 2015 and 2014, the Company entered into various transactions with Dakota Prairie. See Note 4 for further information on Dakota Prairie transactions.

On December 30, 2015, the Company entered into an agreement with Heritage in which Heritage made an uncommitted prepayment for the purchase of certain finished products and entered into an unsecured note payable with the Company as the borrower. See Note 7 for further information on this agreement.

17. Segments and Related Information

a. Segment Reporting

The Company manages its business in multiple operating segments, which are grouped on the basis of similar product, market and operating factors into the following reportable segments:

- Specialty Products. The specialty products segment produces a variety of lubricating oils, solvents, waxes, synthetic lubricants and other products which are sold to customers who purchase these products primarily as raw material components for basic automotive, industrial and consumer goods. Specialty products also include synthetic lubricants used in manufacturing, mining and automotive applications.
- Fuel Products. The fuel products segment produces primarily gasoline, diesel, jet fuel and asphalt which are primarily sold to customers located in the PADD 2, PADD 3 and PADD 4 areas within the U.S.

- Oilfield Services. The oilfield services segment markets its products and oilfield services including drilling fluids, completion fluids and solids control services to the oil and gas industry.

During the fourth quarter 2014, the Company realigned its reportable segments for financial reporting purposes as a result of the Anchor and SOS Acquisitions in 2014 resulting in a new segment, oilfield services. Prior to this change, Anchor and SOS were reported as part of the specialty products segment. This reporting change did not impact the Company's consolidated results.

The accounting policies of the reporting segments are the same as those described in the summary of significant accounting policies as disclosed in Note 2, except that the disaggregated financial results for the reporting segments have been prepared using a management approach, which is consistent with the basis and manner in which management internally disaggregates financial information for the purposes of assisting internal operating decisions. The Company accounts for intersegment sales and transfers at cost plus a specified mark-up. The Company evaluates performance based upon Adjusted EBITDA. The Company defines Adjusted EBITDA for any period as: (1) net income (loss) plus (2)(a) interest expense; (b) income taxes; (c) depreciation and amortization; (d) unrealized losses from mark to market accounting for hedging activities; (e) realized gains under derivative instruments excluded from the determination of net income (loss); (f) non-cash equity based compensation expense and other non-cash items (excluding items such as accruals of cash expenses in a future period or amortization of a prepaid cash expense) that were deducted in computing net income (loss); (g) debt refinancing fees, premiums and penalties and (h) all extraordinary, unusual or non-recurring items of gain or loss, or revenue or expense; minus (3)(a) unrealized gains from mark to market accounting for hedging activities; (b) realized losses under derivative instruments excluded from the determination of net income and (c) other non-recurring expenses and unrealized items that reduced net income (loss) for a prior period, but represent a cash item in the current period.

The Company manages its assets on a total company basis, not by segment. Therefore, management does not review any asset information by segment and, accordingly, the Company does not report asset information by segment.

Table of Contents
CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Reportable segment information is as follows (in millions):

Year Ended December 31, 2015	Specialty Products	Fuel Products	Oilfield Services	Combined Segments	Eliminations	Consolidated Total
Sales:						
External customers	$1,367.8	$2,562.5	$282.5	$4,212.8	$—	$4,212.8
Intersegment sales	3.9	39.1	—	43.0	(43.0)	—
Total sales	$1,371.7	$2,601.6	$282.5	$4,255.8	$(43.0)	$4,212.8
Loss from unconsolidated affiliates	$—	$(61.1)	$(0.4)	$(61.5)	$—	$(61.5)
Adjusted EBITDA	$201.7	$81.9	$(25.9)	$257.7	$—	$257.7
Reconciling items to net loss:						
Depreciation and amortization	69.2	82.4	22.8	174.4	—	174.4
Realized loss on derivatives, not reflected in net loss or settled in a prior period	(3.0)	(7.0)	—	(10.0)	—	(10.0)
Impairment charges	—	24.3	33.8	58.1	—	58.1
Unrealized loss on derivatives						39.5
Interest expense						104.9
Debt extinguishment costs						46.6
Non-cash equity based compensation and other items						12.0
Income tax benefit						(28.4)
Net loss						$(139.4)

Year Ended December 31, 2014	Specialty Products	Fuel Products	Oilfield Services	Combined Segments	Eliminations	Consolidated Total
Sales:						
External customers	$1,729.2	$3,693.4	$368.5	$5,791.1	$—	$5,791.1
Intersegment sales	18.4	89.8	—	108.2	(108.2)	—
Total sales	$1,747.6	$3,783.2	$368.5	$5,899.3	$(108.2)	$5,791.1
Loss from unconsolidated affiliates	$—	$(3.2)	$(0.2)	$(3.4)	$—	$(3.4)
Adjusted EBITDA	$220.8	$50.0	$35.1	$305.9	$—	$305.9
Reconciling items to net loss:						
Depreciation and amortization	68.1	80.0	15.0	163.1	—	163.1
Realized gain (loss) on derivatives, not reflected in net loss or settled in a	(1.9)	8.5	—	6.6	—	6.6

prior period						
Impairment charges	—	—	36.0	36.0	—	36.0
Unrealized loss on derivatives						0.6
Interest expense						110.8
Debt extinguishment costs						89.9
Non-cash equity based compensation and other items						11.9
Income tax benefit						(0.8)
Net loss						$(112.2)

146

Table of Contents
CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Year Ended December 31, 2013	Specialty Products	Fuel Products	Oilfield Services	Combined Segments	Eliminations	Consolidated Total
Sales:						
External customers	$1,774.9	$3,646.5	$—	$5,421.4	$—	$5,421.4
Intersegment sales	—	77.3	—	77.3	(77.3)	—
Total sales	$1,774.9	$3,723.8	$—	$5,498.7	$(77.3)	$5,421.4
Loss from unconsolidated affiliates	$—	$(0.3)	$—	$(0.3)	$—	$(0.3)
Adjusted EBITDA	$194.5	$47.0	$—	$241.5	$—	$241.5
Reconciling items to net income:						
Depreciation and amortization	66.6	67.1	—	133.7	—	133.7
Realized loss on derivatives, not reflected in net income or settled in a prior period	(0.5)	(1.3)	—	(1.8)	—	(1.8)
Impairment charges	10.5	—	—	10.5	—	10.5
Unrealized gain on derivatives						(25.7)
Interest expense						96.8
Debt extinguishment costs						14.6
Non-cash equity based compensation and other items						9.5
Income tax expense						0.4
Net income						$3.5

b. Geographic Information

International sales accounted for less than 10% of consolidated sales in each of the three years ended December 31, 2015, 2014 and 2013. Substantially all of the Company’s long-lived assets are domestically located.

Table of Contents

c. Product Information

The Company offers specialty products primarily in categories consisting of lubricating oils, solvents, waxes, packaged and synthetic specialty products and other. Fuel products categories primarily consist of gasoline, diesel, jet fuel, asphalt, heavy fuel oils and other. All oilfield services products are consolidated in a standalone category. The following table sets forth the major product category sales (in millions):

	Year Ended December 31,								
	2015			2014			2013		
Specialty products:									
Lubricating oils	$575.6	13.7	%	$748.4	12.9	%	$848.8	15.7	%
Solvents	302.0	7.2	%	485.2	8.4	%	511.7	9.4	%
Waxes	136.9	3.2	%	144.1	2.5	%	141.0	2.6	%
Packaged and synthetic specialty products	316.6	7.5	%	313.5	5.4	%	233.6	4.3	%
Other	36.7	0.9	%	38.0	0.7	%	39.8	0.7	%
Total	1,367.8	32.5	%	1,729.2	29.9	%	1,774.9	32.7	%
Fuel products:									
Gasoline	1,047.1	24.9	%	1,443.1	24.9	%	1,409.4	26.0	%
Diesel	894.8	21.2	%	1,197.4	20.7	%	1,259.2	23.3	%
Jet fuel	149.6	3.6	%	199.3	3.4	%	191.4	3.5	%
Asphalt, heavy fuel oils and other	471.0	11.1	%	853.6	14.7	%	786.5	14.5	%
Total	2,562.5	60.8	%	3,693.4	63.7	%	3,646.5	67.3	%
Oilfield services:									
Total	282.5	6.7	%	368.5	6.4	%	—	—	%
Consolidated sales	$4,212.8	100.0	%	$5,791.1	100.0	%	$5,421.4	100.0	%

d. Major Customers

During the years ended December 31, 2015, 2014 and 2013, the Company had no customer that represented 10% or greater of consolidated sales.

e. Major Suppliers

During the years ended December 31, 2015, 2014 and 2013, the Company had two suppliers that supplied approximately 52.2%, 45.9% and 54.1%, respectively, of its crude oil supply.

Table of Contents

18. Quarterly Financial Data (Unaudited)

The table below sets forth selected quarterly financial data for each of the last two fiscal years (in millions, except unit and per unit data):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total [1]
2015					
Sales	$1,018.6	$1,156.2	$1,140.0	$898.0	$4,212.8
Gross profit	195.2	202.7	164.8	31.9	594.6
Net income (loss)	23.8	2.5	(48.9)	(116.8)	(139.4)
Net income (loss) available to limited partners	19.1	(1.7)	(52.2)	(118.6)	(153.4)
Limited partners' interest basic and diluted net income (loss) per unit	$0.27	$(0.02)	$(0.68)	$(1.56)	$(2.05)
Weighted average limited partner units outstanding — basic	71,232,392	76,092,517	76,112,325	76,124,133	
Weighted average limited partner units outstanding — diluted	71,275,452	76,092,517	76,112,325	76,124,133	
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total [1]
2014					
Sales	$1,341.0	$1,434.9	$1,675.8	$1,339.4	$5,791.1
Gross profit	124.8	99.0	182.6	123.3	529.7
Net income (loss)	(49.8)	(8.3)	9.4	(63.5)	(112.2)
Net income (loss) available to limited partners	(52.6)	(12.0)	5.4	(66.2)	(125.4)
Limited partners' interest basic and diluted net income (loss) per unit	$(0.76)	$(0.17)	$0.08	$(0.95)	$(1.80)
Weighted average limited partner units outstanding — basic	69,622,884	69,604,669	69,684,621	69,775,827	
Weighted average limited partner units outstanding — diluted	69,622,884	69,604,669	69,850,685	69,775,827	

[1] The sum of the four quarters may not equal the total year due to rounding.

19. Subsequent Events

On January 19, 2016, the Company declared a quarterly cash distribution of $0.685 per unit on all outstanding common units, or approximately $57.4 million (including the general partner's incentive distribution rights) in aggregate, for the quarter ended December 31, 2015. The distribution was paid on February 12, 2016, to unitholders of record as of the close of business on February 2, 2016. This quarterly distribution of $0.685 per unit equates to $2.74 per unit, or approximately $229.6 million (including the general partner's incentive distribution rights) in aggregate on an annualized basis.

The fair value of the Company's derivatives that were outstanding as of December 31, 2015, decreased by approximately $9.0 million subsequent to December 31, 2015, to a net liability of approximately $38.0 million. The fair value of the Company's senior notes has decreased by approximately $455.0 million subsequent to December 31, 2015.

149

Table of Contents

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

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 Annual Report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of December 31, 2015 at the reasonable assurance level. See Management's Report on Internal Control Over Financial Reporting included in Item 8 "Financial Statements and Supplementary Data."

Changes in Internal Control over Financial Reporting

During the quarterly period ended December 31, 2015, our principal executive officer and principal financial officer identified a material weakness related to the design of management review controls related to the proper determination of the lower of cost or market inventory calculation. A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected in a timely basis. This control deficiency resulted in the reasonable possibility that a material misstatement in the lower of cost or market inventory adjustment would not be prevented or detected in a timely basis. This material weakness was identified and corrected prior to the completion of our consolidated financial statements included in this Annual Report on Form 10-K.

Remediation Plan

The Audit Committee directed our management to prepare a remediation plan concerning the material weakness described above. As a result, we remediated this material weakness by, among other things, implementing and modifying certain accounting processes and procedures during the quarterly period ended December 31, 2015, particularly those that involve our controls surrounding the oversight and review of the lower of cost or market inventory calculation.

As of December 31, 2015, management has determined that, as a result of its remediation efforts, it no longer has a material weakness in internal controls for the lower of cost or market inventory calculation.

Item 9B. Other Information

None.

Table of Contents

PART III

Item 10. Directors, Executive Officers of Our General Partner and Corporate Governance

Management of Calumet Specialty Products Partners, L.P. and Director Independence

Our general partner, Calumet GP, LLC, manages our operations and activities. Unitholders are limited partners and are not entitled to elect the directors of our general partner or directly or indirectly participate in our management or operations. Our general partner owes a fiduciary duty to our unitholders, as limited by the various provisions of our partnership agreement modifying and restricting the fiduciary duties that might otherwise be owed by our general partner to our unitholders.

The directors of our general partner oversee our operations. The owners of our general partner have appointed seven members to our general partner's board of directors. The directors of our general partner are generally elected by a majority vote of the owners of our general partner on an annual basis. However, as long as our executive vice chairman of our general partner, F. William Grube, or trusts established for the benefit of his family members, continue to own at least 30% of the membership interests in our general partner, Mr. Grube (or in certain specified instances, his designee or transferee) has the right to serve as a director of our general partner. The directors of our general partner hold office until the earlier of their death, resignation, removal or disqualification or until their successors have been elected and qualified.

Pursuant to Section 4360 of the NASDAQ Stock Market, LLC Marketplace Rules ("NASDAQ Rules"), a listed limited partnership like us is not required to have a majority of independent directors on the board of directors of our general partner or to establish a compensation committee or a nominating/governance committee. However, three of our general partner's seven directors are "independent" as that term is defined in the NASDAQ Rules and Rule 10A-3 of the Exchange Act. In determining the independence of each director, our general partner has adopted standards that incorporate the NASDAQ Rules and Exchange Act standards. Our general partner's independent directors as determined in accordance with those standards are: James S. Carter, Robert E. Funk and George C. Morris III.

The officers of our general partner manage the day-to-day affairs of our business. Officers serve at the discretion of the board of directors.

Directors and Executive Officers

The following table shows information regarding the directors and executive officers of Calumet GP, LLC as of February 29, 2016:

Name	Age	Position with Calumet GP, LLC
Fred M. Fehsenfeld, Jr.	65	Chairman of the Board
F. William Grube	68	Executive Vice Chairman
Timothy Go	49	Chief Executive Officer
R. Patrick Murray, II	44	Executive Vice President, Chief Financial Officer and Secretary
William A. Anderson	47	Executive Vice President — Sales
Edward F. Juno	63	Executive Vice President — Fuels Operations
James S. Carter	67	Director
Robert E. Funk	70	Director
George C. Morris III	60	Director
Daniel J. Sajkowski	56	Director
Amy M. Schumacher	44	Director

Each director's biographical information set forth below includes the particular experience and qualifications that led the board of directors to conclude that the director is qualified to serve in such capacity.

Fred M. Fehsenfeld, Jr. has served as the chairman of the board of our general partner since September 2005. Mr. Fehsenfeld also served as the vice chairman of the board of our Predecessor from 1990 until our initial public offering. Mr. Fehsenfeld has worked for The Heritage Group in various capacities since 1977 and has served as its managing trustee since 1980. Mr. Fehsenfeld received his B.S. in Mechanical Engineering from Duke University and his M.S. in Management from the Massachusetts Institute of Technology Sloan School.

As co-founder of our Predecessor, Mr. Fehsenfeld has an extensive knowledge base regarding the Company's operations and has participated in all major strategic decision making for the Company and our Predecessor since their inception. In his role as managing trustee of The Heritage Group, Mr. Fehsenfeld serves in lead executive roles, including the role of chairman and chief executive officer, for a multitude of different companies within The Heritage Group, providing a breadth of experience in leadership and management across a wide variety of industries, including energy. Since 2008, Mr. Fehsenfeld has served as chairman of the board of directors of Heritage-Crystal Clean, Inc., a publicly-traded environmental services company which is owned in part by The Heritage Group. Mr. Fehsenfeld is the father of Amy M. Schumacher, member of the board of directors of our general partner.

F. William Grube has served as the executive vice chairman of the board of our general partner since April 2015. From January 2011 through April 2015, Mr. Grube served as chief executive officer and vice chairman of the board of our general partner. From September 2005 through December 2010, Mr. Grube served as chief executive officer, president and director of our general partner. Mr. Grube has also served as president and chief executive officer of our Predecessor from 1990 until our initial public offering. From 1973 to 1989, Mr. Grube served as executive vice president of Rock Island Refining Corporation. Mr. Grube received his B.S. in Chemical Engineering from Rose-Hulman Institute of Technology and his M.B.A. from Harvard University.

As co-founder of our Predecessor and through his role as prior chief executive officer, Mr. Grube possesses unique experience relative to the management of the Company on a day-to-day basis over a significant time period and across all functional areas of the Company. Mr. Grube has significant technical expertise in refining developed over the course of his career, with both the Company and our Predecessor, as well as another refining company which specialized in the production of fuel products.

Timothy Go has served as chief executive officer of our general partner since January 2016. Prior to joining the Company, Mr. Go served as vice president — operations of Flint Hills Resources, LP, a wholly owned subsidiary of Koch Industries, Inc., since July 2013. From June 2011 through July 2013, Mr. Go served as vice president — operations excellence of Flint Hills Resources, LP. From August 2008 through June 2011, Mr. Go served as managing director — operations excellence of Koch Industries, Inc. Mr. Go received a B.S. in Chemical Engineering from the University of Texas at Austin.

R. Patrick Murray, II has served as executive vice president, chief financial officer and secretary of our general partner since October 2014. From December 2012 through October 2014, Mr. Murray served as senior vice president, chief financial officer and secretary of our general partner. From September 2005 through December 2012, Mr. Murray served as vice president, chief financial officer and secretary of our general partner. Mr. Murray served as the vice president and chief financial officer of our Predecessor from 1999 until our initial public offering and served as its controller from 1998 to 1999. From 1993 to 1998, Mr. Murray was a senior auditor with Arthur Andersen LLP. Mr. Murray received his B.B.A. in Accountancy from the University of Notre Dame.

William A. Anderson has served as executive vice president — sales of our general partner since October 2014. From October 2012 through October 2014, Mr. Anderson served as vice president — marketing and new products. From September 2005 through September 2012, Mr. Anderson served as vice president — sales of our general partner. Mr. Anderson served as vice president — sales and marketing of our Predecessor from 2000 until our initial public offering and served in various other capacities from 1993 to 2000. Mr. Anderson received his B.A. in Communications from DePauw University.

Edward F. Juno has served as executive vice president — fuels operations since November 2015. From March 2015 through November 2015, Mr. Juno served as executive vice president — operations. From December 2012 through March 2015, Mr. Juno served as vice president — refining technology. Prior to joining the Company, Mr. Juno served as vice president of West Coast refining with Alon USA Energy, Inc. from January 2010 through December 2012. From July 2003 through January 2010, Mr. Juno held various management positions at Sinclair Energy Corporation. From January 1988 through July 2003, Mr. Juno held various engineering, operations and management positions at CITGO Petroleum Corporation and Pennzoil Products Company. Mr. Juno received his B.S. in Chemical Engineering from Kansas State University.

James S. Carter has served as a member of the board of directors of our general partner since January 2006. Mr. Carter worked in various capacities at ExxonMobil including vice president of U.S. marketing and sales of fuels and specialty products, manager of U.S. refining and marketing planning and analysis, manager of U.S. distribution activities, analysis manager of ExxonMobil International, and advisor to ExxonMobil headquarters for European refining and marketing until his retirement in 2003. Mr. Carter received his B.S. in Mechanical Engineering from Clemson University and his M.B.A. in Finance and Accounting from Tulane University.

Mr. Carter brings extensive marketing and managerial experience with one of the largest integrated energy companies in the world. He possesses a broad background in petroleum products marketing, with specific experience in the marketing of fuel products.

Robert E. Funk has served as a member of the board of directors of our general partner since January 2006. Mr. Funk previously served as vice president — corporate planning and economics of CITGO Petroleum Corporation, a refiner and marketer of transportation fuels, lubricants, petrochemicals, refined waxes, asphalt and other industrial products, from 1997 until his retirement in December 2004. Mr. Funk previously served CITGO or its predecessor, Cities Services Company, as general manager — facilities planning from 1988 to 1997, general manager — lubricants operations from 1983 to 1988 and manager — refinery east, Lake Charles refinery from 1982 to 1983. Mr. Funk received his B.S. in Chemical Engineering from the University of Kansas.

Mr. Funk has extensive refining industry experience including planning, operations and managerial roles for a large multinational refining company. His broad background of experience provides helpful insight to the Company in its implementation of strategic initiatives and its refinery operations in general.

George C. Morris III has served as a member of the board of directors of our general partner since May 2009. Mr. Morris has served as president of Morris Energy Advisors, Inc. since March 2009 and most recently served as a managing director at Merrill Lynch & Co. from December 2006 until his retirement in March 2009. Mr. Morris served as a managing director of investment banking at Petrie Parkman & Co. until its acquisition by Merrill Lynch in December 2006 and also served as a managing director of investment banking at Simmons & Company International and as a director of investment banking at First Boston Corporation. Mr. Morris holds B.B.A. and M.B.A. degrees from the University of Texas and a J.D. from Southern Methodist University. Mr. Morris is also a member of the board of directors of Arch Coal, Inc., a public company which produces thermal and metallurgical coal from surface and underground mines.

Mr. Morris' long tenure in the investment banking industry with a focus on the energy sector provides a unique breadth of experience to the board of directors in areas of finance and capital markets. In his role as a financial advisor to the Company prior to joining the board of directors, Mr. Morris gained significant insight into the Company's operations and strategy.

Daniel J. Sajkowski has served as a member of the board of directors of our general partner since September 2014. Mr. Sajkowski has served as executive vice president, growth and new ventures of The Heritage Group since 2013. Prior to joining The Heritage Group, Mr. Sajkowski was the senior director — downstream technology at Sapphire Energy from 2010 until 2013. From 2004 to 2010, Mr. Sajkowski served as business unit leader at BP's Whiting, Indiana refinery. During his career with BP/Amoco, Mr. Sajkowski also held positions as the manager of integrated supply and trading from 2002 until 2004 and vice president of refining technology from 2000 until 2002. Mr. Sajkowski earned his B.S. and M.S. degrees in Chemical Engineering from the University of Michigan and a Ph.D. in Chemical Engineering from Stanford University in 1986. He also completed The General Manager Program at Harvard University in 2000.

Mr. Sajkowski has extensive refining industry experience including planning, operations and managerial roles for a large multinational refining company. His broad background of experience provides helpful insight to the Company in its implementation of strategic initiatives and its refinery operations in general.

Amy M. Schumacher has served as a member of the board of directors of our general partner since September 2014. Ms. Schumacher has served as the president of Monument Chemicals, Inc. and Haltermann Solutions since 2010. Prior to joining Monument Chemicals, Inc. and Haltermann Solutions, Ms. Schumacher worked in various capacities for The Heritage Group leading a variety of growth projects from 2003 until 2010. From 1998 to 2003, Ms. Schumacher was a consultant with Accenture. Ms. Schumacher received her B.S. in Civil Engineering from Purdue University and her M.S. in Management from the Massachusetts Institute of Technology Sloan School. Ms. Schumacher currently serves as a trustee for The Heritage Group and sits on a number of private subsidiary boards. Ms. Schumacher is the daughter of Fred M. Fehsenfeld, Jr., the chairman of the board of our general partner.

Ms. Schumacher has extensive managerial experience including planning and strategy. She possesses a broad background within the chemicals industry, with specific experience in strategic growth projects.

Board of Directors Committees

Conflicts Committee

Two members of the board of directors of our general partner serve on a conflicts committee to review specific matters that the board believes may involve conflicts of interest. The conflicts committee determines if the resolution of the conflict of interest is fair and reasonable to us. The members of the conflicts committee may not be owners, officers or employees of our general partner or directors, officers, or employees of its affiliates, and must meet the independence and experience standards established by NASDAQ and the Exchange Act to serve on an audit committee of a board of directors, and certain other requirements. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners, and not a breach by our general partner of any duties it may owe us or our unitholders. The two independent board members who serve on the conflicts committee are Messrs. James S. Carter and Robert E. Funk. Mr. Carter serves as the chairman of the conflicts committee.

Compensation Committee

The board of directors of our general partner also has a compensation committee which, among other responsibilities, has overall responsibility for evaluating and either approving or recommending to the board of directors the director, chief executive officer and senior executive compensation plans, policies and programs of the Company. NASDAQ does not require a limited partnership like us to have a compensation committee comprised entirely of independent directors. Accordingly, Messrs. Fred M. Fehsenfeld, Jr. and F. William Grube serve as members of our compensation committee. Mr. Fehsenfeld serves as the chairman of the compensation committee.

Table of Contents

The board of directors has adopted a written charter for the compensation committee which defines the scope of the committee's authority. The committee may form and delegate some or all of its authority to subcommittees comprised of committee members when it deems appropriate. The committee is responsible for reviewing and recommending to the board of directors for its approval the annual salary and other compensation components for the chief executive officer. The committee reviews and makes recommendations to the board of directors for its approval of any of the Company's equity compensation-based plans, including the Long-Term Incentive Plan, or any cash bonus or incentive compensation plans or programs. Also, the committee reviews and approves all annual salary and other compensation arrangements and components for the senior executives of the Company. Further, the compensation committee periodically reviews and makes a recommendation to the board of directors for changes in the compensation of all directors. The committee has the authority to retain or terminate any compensation consultant that assists it in the evaluation of director and senior executive compensation and to obtain independent advice and assistance from internal and external legal, accounting and other advisors.

See Item 11 "Executive and Director Compensation — Compensation Discussion and Analysis — Peer Group and Compensation Targets" for additional discussion regarding the results of this executive compensation review.

Audit Committee

The board of directors of our general partner has an audit committee comprised of three directors, Messrs. James S. Carter, Robert E. Funk and George C. Morris III, each of whom the board of directors of our general partner has determined meets the independence and experience standards established by NASDAQ and the SEC. In addition, the board of directors of our general partner has determined that Mr. Morris is an "audit committee financial expert" as defined by the SEC. Mr. Morris serves as the chairman of the audit committee.

The board of directors has adopted a written charter for the audit committee. The audit committee assists the board of directors in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and corporate policies and controls. The audit committee has the sole authority to retain and terminate our independent registered public accounting firm, approves all auditing services and related fees and the terms thereof and pre-approves any non-audit services to be rendered by our independent registered public accounting firm. The audit committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm is given unrestricted access to the audit committee.

Code of Ethics

We have adopted a Code of Business Conduct and Ethics that applies to all directors, officers and employees. Available on our website at www.calumetspecialty.com are copies of our board of directors committee charters and Code of Business Conduct and Ethics, all of which also will be provided to unitholders without charge upon their written request to: Investor Relations, Calumet Specialty Products Partners, L.P., 2780 Waterfront Parkway East Drive, Suite 200, Indianapolis, Indiana, 46214.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934, as amended, requires Calumet's directors and certain executive officers, as well as beneficial owners of ten percent or more of Calumet's common units, to report their holdings and transactions in Calumet's securities. Based on information furnished to Calumet and contained in reports filed pursuant to Section 16(a), as well as written representations that no other reports were required for 2015, Calumet's directors and executive officers filed all reports required by Section 16(a) with the exception of (i) one late filing related to a phantom unit grant and related vesting on November 3, 2015 for Fred M. Fehsenfeld, Jr., (ii) one late filing related to a phantom unit grant and related vesting on November 3, 2015 for James S. Carter, (iii) one late filing related to a phantom unit grant and related vesting on November 3, 2015 for George C. Morris, III, (iv) one late filing related to a phantom unit grant and related vesting on November 3, 2015 for Robert E. Funk, (v) one late filing related to a phantom unit grant and related vesting on November 3, 2015 for Amy M. Schumacher.

Table of Contents

Item 11. Executive and Director Compensation

Compensation Discussion and Analysis

Overview

For purposes of this Compensation Discussion and Analysis and the compensation tables that follow, the names and positions of our named executive officers for the 2015 year were:

- F. William Grube — Chief Executive Officer and Vice Chairman of the Board through March 31, 2015 (Executive Vice Chairman of the Board as of April 1, 2015)
- William H. Hatch — Interim Chief Executive Officer commencing on April 1, 2015
- R. Patrick Murray, II — Executive Vice President, Chief Financial Officer and Secretary
- William A. Anderson — Executive Vice President — Sales
- Edward F. Juno — Executive Vice President — Fuels Operations
- Jennifer G. Straumins — Former Executive Vice President — Strategy and Development (resigned effective March 31, 2015)

Mr. Hatch transitioned into a new role of an executive advisor beginning on January 1, 2016. Mr. Timothy Go became our new chief executive officer on January 1, 2016, but due to the fact that the SEC's compensation disclosure requires information regarding named executive officers as of December 31, 2015, Mr. Go's compensation information will be included in the executive compensation disclosures relating to the 2016 fiscal year.

Ms. Straumins' employment ended on March 31, 2015, however due to the fact that the SEC's compensation disclosure requires information regarding up to two former executives who served as executive officers during any part of the last completed fiscal year but who were not serving as executive officers at the end of the last completed fiscal year, provided such individuals' total compensation for the portion of the year served would have made the individual one of the three most highly compensated executives for the last completed fiscal year, Ms. Straumins' compensation information is included in the executive compensation disclosures relating to the 2015 fiscal year.

The compensation committee of the board of directors of our general partner oversees our compensation programs. Our general partner maintains compensation and benefits programs designed to allow us to attract, motivate and retain the best possible employees to manage us, including executive compensation programs designed to reward the achievement of both short-term and long-term goals necessary to promote growth and generate positive unitholder returns. Our general partner's executive compensation programs are based on a pay-for-performance philosophy, including measurement of our performance against a specified financial target, namely Distributable Cash Flow. Our executive compensation programs include both long-term and short-term compensation elements which, together with base salary and employee benefits, constitute a total compensation package intended to be competitive with similar companies.

Under their collective authority, the compensation committee and the board of directors maintain the right to develop and modify compensation programs and policies as they deem appropriate. Factors they may consider in making decisions to materially increase or decrease compensation include our overall financial performance, our growth over time, our changes in complexity as well as individual executive job scope, complexity and performance, and changes in competitive compensation practices in our defined labor markets. In determining any forms of compensation other than the base salary for the senior executives, or in the case of the chief executive officer, the recommendation to the board of directors of the forms of compensation for the chief executive officer, the compensation committee considers our financial performance and relative unitholder return, the value of similar incentive awards to senior executives at comparable companies and the awards given to senior executives in past years.

Financial Performance Metric Used in Compensation Programs

Our primary business objective is to generate cash flows to make distributions to our unitholders. As a result, our Distributable Cash Flow is the primary measurement of performance taken into account in setting policies and making compensation decisions, as we believe this represents the most comprehensive measurement of our ability to generate cash flows. In 2015, the compensation committee excluded the impact of lower of cost or market ("LCM") inventory adjustments, but included the loss from unconsolidated affiliates (excluding the impairment charge related to our investment in Juniper GTL LLC) in the calculation of Distributable Cash Flow used for incentive compensation purposes. Both short-term and long-term forms of executive compensation are specifically structured on our achievement relative to annual Distributable Cash Flow goals and, as such, determination of related awards, as well as their grant or payment, occurs subsequent to the end of each fiscal year upon final determination of Distributable Cash Flow. We believe that including this financial objective as the primary performance measurement to determine compensation awards for all of our executive officers recognizes the integrated and collaborative effort required by the full executive team to maximize performance. Distributable Cash Flow is a non-GAAP measure that we define, consistent with the terms of our revolving credit agreement and senior notes indentures, as our Adjusted EBITDA less replacement capital expenditures, cash interest expense, turnaround costs, income (loss) from unconsolidated affiliates and income tax expense (benefit). Please refer to Part II, Item 6 “Selected Financial Data — Non-GAAP Financial Measures” for our definition of Adjusted EBITDA.

Peer Group and Compensation Targets

To evaluate all areas of executive compensation, the compensation committee seeks the additional input of outside compensation consultants and available comparative information to validate that the compensation programs established for our executives are consistent with the philosophy of compensating our executives at ranges that approximate within 10% of the median of market for companies of similar size to us. In 2014, the compensation committee retained Buck Consultants, LLC (“Buck Consultants”) as an independent consultant to review our general partner’s executive compensation programs. Buck Consultants reported directly to the compensation committee and did not provide any additional services to our general partner. The scope of this engagement included the following:

- review of a peer group of primarily publicly-traded master limited partnerships for executive compensation comparisons;
- analysis of market pay levels and trends for our named executive officers, other officers and key employees from peer companies including base salary, annual incentives and long-term incentives; and
- assessment of Calumet’s executive pay levels relative to overall market levels.

The following master limited partnerships and corporations were included by Buck Consultants in the peer group for the compensation review: Alon USA Energy, Inc., the former Atlas Pipeline Partners, L.P., Boardwalk Pipeline Partners, LP, Buckeye Partners, L.P., Crestwood Equity Partners LP, EnLink Midstream LLC, CVR Refining, LP, DCP Midstream Partners, LP, Delek US Holdings, Inc., Enbridge Energy Partners, L.P., EnLink Midstream Partners, LP, Genesis Energy, L.P., Kinder Morgan, Inc., Magellan Midstream Partners, L.P., MarkWest Energy Partners, L.P., NGL Energy Partners LP, Northern Tier Energy LP, NuStar Energy L.P., ONEOK Partners, L.P., the former Regency Energy Partners LP, Targa Resources Partners LP and Williams Partners L.P. Peer group companies were validated and selected based on their comparability of EBITDA (a non-GAAP measurement), sales and market capitalization to those of Calumet. Market data compiled from public disclosures of the peer group companies were used in the review to compare our compensation of the key executive group against the market. Buck Consultants provided a presentation of its findings to the compensation committee in November 2014 that assisted us in making the compensation decisions described below for the 2015 year.

The compensation committee used the findings of the Buck Consultants executive compensation review to validate the total competitiveness of compensation for our key executives, including each named executive officer. Specifically, the Buck Consultants review indicated that aggregate target total direct compensation of our key executives, which includes all the major elements of our executive compensation program, including base salary, short-term incentives and long-term compensation, was within the median of market by approximately 10%. Long-term incentives for the key executives were within the 25th percentile of the peer group by approximately 10%, which the compensation committee deemed appropriate given our smaller size relative to certain master limited partnerships included in the peer group, with an expectation by the compensation committee that with future achievement of strategic goals and further growth in financial performance, such long-term incentive opportunities should migrate toward the median level of the peer group. As of this filing, we have not made any material changes to our compensation program for the 2016 year.

Review of Named Executive Officer Performance

The compensation committee reviews, on an annual basis, each compensation element for a named executive officer. In each case, the compensation committee takes into account the scope of responsibilities and experience and balances these against competitive salary levels. The compensation committee has the opportunity to meet with the named executive officers at various times during the year, which allows the compensation committee to form its own assessment of each individual’s performance.

Objectives of Compensation Programs

Our executive compensation programs are designed with the following primary objectives:

- reward strong individual performance that drives our positive financial results;
- make incentive compensation a significant portion of an executive's total compensation, designed to balance short-term and long-term performance;
- align the interests of our executives with those of our unitholders; and
- attract, develop and retain executives with a compensation structure that is competitive with other publicly-traded partnerships of similar size.

Elements of Executive Compensation

The compensation committee believes the total compensation and benefits program for our named executive officers should consist of the following:

- base salary;
- annual incentive plan which includes short-term cash awards and also includes an optional deferred compensation element;
- long-term incentive compensation, including unit-based awards;
- retirement, health and welfare benefits; and
- perquisites.

These elements are designed to constitute an integrated executive compensation structure meant to incentivize a high level of individual executive officer performance in line with our financial and operating goals.

Base Salary

Design. Salaries provide executives with a base level of semi-monthly income as consideration for fulfillment of certain roles and responsibilities. The salary program assists us in achieving our objective of attracting and retaining the services of quality individuals who are essential for the growth and profitability of Calumet. Generally, changes in the base salary levels for our named executive officers are determined on an annual basis by the compensation committee of the board of directors and are effective at the beginning of the following fiscal year.

Results. The 2015 base salaries for Mr. Grube, Mr. Hatch, Mr. Murray, Mr. Anderson, Mr. Juno and Ms. Straumins were $454,363, $500,000, $339,488, $312,626, $263,831and $371,315, respectively, although amounts in the Summary Compensation Table below will reflect pro-rata values based upon the portion of the year in which the executive was providing services to us. These 2015 base salaries for Mr. Grube, Mr. Murray, Mr. Anderson and Ms. Straumins compare to $441,129, $329,600, $279,130 and $360,500, respectively, in 2014. The levels of increases in the base salaries for Mr. Grube, Mr. Murray and Ms. Straumins were a 3.0% increase from 2014 levels.

Compensation Changes for 2016. With respect to our named executive officers, the compensation committee approved increased salaries for certain executives as part of its annual salary review process. Effective January 1, 2016, the base salaries were increased for Messrs. Murray and Anderson to $353,067 and $325,130, respectively. The levels of increases in the base salaries for Messrs. Murray and Anderson were based on the approximate average of the percentage increase of all salaried employees for 2016. Effective January 1, 2016, the base salary for Mr. Juno is $272,537. The level of increase takes into account his increased job responsibilities resulting from his promotion to executive vice president - fuels operations. The compensation committee also considered the increases to base salary to be appropriate based on comparisons against our peer group of publicly traded partnerships in an effort to ensure that base salaries were closer to the market median of our peer group.

Short-Term Cash Awards

Design. Under the Cash Incentive Compensation Plan (the “Cash Incentive Plan”), short-term cash awards are designed to aid us in retaining and motivating executives to assist us in meeting our financial performance objectives on an annual basis. Short-term cash awards are granted to named executive officers and certain other management employees based on our achievement of performance targets on our Distributable Cash Flow, thereby establishing a direct link between executive compensation and our financial performance.

The compensation committee establishes minimum, target and stretch incentive opportunities for each executive officer and other key employees expressed as a percentage of base salary. The amount that is paid out is based on our achievement of a minimum, target or stretch level of Distributable Cash Flow during the fiscal year. The compensation committee may determine whether the applicable performance period will be a full calendar year or a specific portion of a calendar year, depending upon our incentive goals for the short-term cash awards for that year. At the recommendation of the compensation committee, the board of directors approves Distributable Cash Flow targets for each performance period based on budgets prepared by management. When making the annual determination of the minimum goal, target goal and stretch goal levels of Distributable Cash Flow, the compensation committee and the board of directors consider the specific circumstances facing us during the relevant year. Generally, the compensation committee seeks to set the minimum goal, target goal and stretch goal levels such that the relative challenge of achieving each level is consistent from year to year. The expectation that management will achieve the minimum goal level is very high, while meaningful additional effort would be required to achieve the target goal and considerable additional effort would be required to achieve the stretch goal.

Generally, no awards are paid under the Cash Incentive Plan unless we achieve at least the minimum Distributable Cash Flow goal. If the minimum, target or stretch level Distributable Cash Flow goal is achieved, participants in the plan will receive their minimum, target or stretch cash award opportunity, respectively. If our Distributable Cash Flow is between specified goal

Table of Contents

levels, participants are eligible to receive a prorated percentage of their cash award opportunity based on where the actual Distributable Cash Flow amount falls between the levels.

The compensation committee established separate short-term cash awards for Mr. Hatch, as a result of his interim position. Mr. Hatch was eligible to receive a quarterly bonus of up to $62,500 based on individual performance in accomplishing certain key goals/milestones (e.g., successful attainment of major capital projects, achievement of certain operational and safety metrics, etc.) monitored by the board of directors. The performance metrics reviewed by the board of directors were used as guidelines rather than as formulaic requirements for the determination of the payment

Results. For fiscal year 2015, the minimum Distributable Cash Flow goal was $151.1 million, the target goal was $203.1 million and the stretch goal was $255.1 million. For the reasons described in “Management’s Discussion and Analysis of Financial Condition and Results of Operations — 2015 Update,” we met at least our target goal with 2015 Distributable Cash Flow of $224.5 million, as defined under the Cash Incentive Plan.

The following table summarizes the levels of cash award opportunity for each named executive officer and the actual percentage earned by them in 2015:

	Cash Incentive Award Opportunity as a Percentage of Base Salary							
	Minimum		Target		Stretch		Actual Payout	
F. William Grube, R. Patrick Murray, II and William A. Anderson	50	%	100	%	200	%	141	%
Edward F. Juno	50	%	100	%	150	%	121	%

Ms. Straumins forfeited her award under the plan for fiscal year 2015 based on the timing of her departure and the terms of the Cash Compensation Incentive Plan.

The compensation committee determined these percentages of base salary at levels, when combined with both base salary and potential long-term, unit-based awards, to develop a total direct compensation structure for the named executive officers which is intended to be within approximately 10% of the median of our peer group, while placing significant emphasis on the achievement of our Distributable Cash Flow goals.

For 2015, the target goal for Distributable Cash Flow was set at the budgeted amount, a level that the board of directors believed reflected the reasonable expectations management had for our financial performance during the fiscal year and likely to be achieved given actual Distributable Cash Flow achieved for the 2014 fiscal year. The board of directors set the stretch Distributable Cash Flow goal at 26% above the budgeted amount, a level which they believed would be attained only with higher levels of performance relative to the reasonable expectations management had for our financial performance and therefore not likely to be achieved. The minimum goal was set at approximately 26% below the budgeted amount. Please read “Management’s Discussion and Analysis of Financial Condition and Results of Operations — 2015 Update,” for a discussion of the factors that impacted our results, including higher sales volume, the primary driver that enabled us to meet our Distributable Cash Flow targets. The following table reflects our historical minimum, target and stretch Distributable Cash Flow goals:

Distributable Cash Flow (In millions)

Fiscal Year	Actual	Minimum Goal	Target Goal	Stretch Goal
2015 (1)	$224.5	$151.1	$203.1	$255.1
2014 (2)	$114.1	$79.9	$110.5	$141.1
2013	$18.5	$175.3	$246.8	$357.6

(1) Actual results exclude an $81.8 million LCM inventory adjustment, include a $37.5 million loss from unconsolidated affiliates and exclude bonus expense for calculation purposes.

(2) Actual, minimum goal, target goal and stretch goal were based on the combined third and fourth quarters of 2014. Actual results exclude bonus expense for calculation purposes.

Mr. Hatch received $187,500 based on individual performance in accomplishing certain key goals/milestones (e.g., successful attainment of major capital projects, achievement of certain operational and safety metrics, etc.) monitored by the board of directors.

Compensation Changes for 2016. Upon the recommendation of the compensation committee, the board of directors has approved new Distributable Cash Flow targets for the 2016 fiscal year based on budgets prepared by management. We do not disclose our confidential 2016 targets, which, if disclosed, would put us at a competitive disadvantage. However, we believe that the targets set for the 2016 year will be difficult to achieve and that there is no guarantee that our named executive officers will receive an award related to the 2016 year.

Table of Contents

For further description of this compensation program, please see "Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table — Description of Cash Incentive Plan."

Executive Deferred Compensation Plan

Design. The compensation committee allows for the participation of the executive officers in the Calumet Specialty Products Partners, L.P. Executive Deferred Compensation Plan (the "Deferred Compensation Plan") to encourage the officers to save for retirement and to assist us in retaining our officers. The Deferred Compensation Plan is intended to promote retention by giving employees an opportunity to save in a tax-efficient manner. The terms governing the retirement benefit under this plan for the executive officers are the same as those available for other eligible employees in the U.S. Pursuant to the Deferred Compensation Plan, a select group of management, including the named executive officers, and all of the non-employee directors are eligible to participate by making an annual irrevocable election to defer, in the case of management, all or a portion of their annual cash incentive award under the Cash Incentive Plan, and, in the case of non-management directors, all or none of their annual cash retainer. The deferred amounts are credited to participants' accounts in the form of phantom units, with each such phantom unit representing a notional unit that entitles the holder to receive either an actual common unit or the cash value of a common unit (determined by using the fair market value of a common unit at the time a determination is needed). The phantom units credited to each participant's account also receive distribution equivalent rights ("DERs"), which are credited to the participant's account in the form of additional phantom units. In our sole discretion, we may make matching contributions of phantom units or purely discretionary contributions of phantom units, in amounts and at times as the compensation committee recommends and the board of directors approves.

Results. On March 13, 2015, we made discretionary matching contributions of phantom units to the accounts of those participants in the Deferred Compensation Plan, including certain of the named executive officers who elected to defer all or a portion of their annual cash incentive award related to the 2014 fiscal year. These contributions, which were subject to continued service vesting requirements, were made as a reward for prior service and future efforts toward our success and growth, as well as an incentive for continued participation through elective deferrals into the Deferred Compensation Plan. Please see Nonqualified Deferred Compensation" for a more detailed disclosure of the value of contributions into this plan, vesting terms, as well as the DERs associated with such contributions.

Long-Term, Unit-Based Awards

Design. Long-term unit-based awards may consist of any type of award allowed pursuant to our Long-Term Incentive Plan, including phantom units, restricted units, unit options, substitution awards and DERs. These awards are granted to employees, consultants and directors of our general partner under the provisions of our Long-Term Incentive Plan, as amended, originally adopted on January 24, 2006, and administered by the compensation committee. These awards aid Calumet in retaining and motivating executives to assist us in meeting our financial performance objectives.

In fiscal year 2015, the annual unit award opportunity to named executive officers consisted of the contingent right to receive phantom units. Under the Long-Term Incentive Plan, phantom units are granted only upon our achievement of specified levels of Distributable Cash Flow. When granted, phantom units are subject to further time-based vesting criteria specified in the grant. Upon satisfaction of the time-based vesting criteria specified in the grant, phantom units convert into common units (or cash equivalent). Accordingly, these awards established a direct link between executive compensation and our financial performance. This component of executive compensation, when coupled with an extended ratable vesting period as compared to cash awards, further aligns the interests of executives with our unitholders in the longer-term and reinforces unit ownership levels among executives.

Results. The following table provides the annual unit award opportunity for each named executive officer. Our general objective when determining the size of the phantom unit awards is to provide our named executive officers with long-term incentive opportunities targeted within approximately 10% of the 25th percentile of peer practices for long-term equity based awards for similarly situated executive officers. The following table reflects the number of phantom units that would be awarded to our named executive officers depending on whether we achieved the Distributable Cash Flow minimum, target or stretch goals discussed above in "Short-Term Cash Awards" as well as the actual number of phantom units earned in 2015, which will be awarded in the first quarter of 2016:

	2015 Phantom Unit Award	Phantom Units

	Opportunity			Earned
	Minimum	Target	Stretch	
F. William Grube	10,800	21,600	32,400	21,600
R. Patrick Murray, II, William A. Anderson and Jennifer G. Straumins (1)	7,200	14,400	21,600	14,400
Edward F. Juno	5,400	10,800	16,200	10,800

Table of Contents

(1) Ms. Straumins did not earn any phantom units in 2015 as a result of her resignation on March 31, 2015.
Phantom units granted are subject to a time-vesting requirement, whereby 25% of the units would vest immediately at grant and the remainder vest ratably over three years on each December 31. These phantom units also receive DERs, which are paid in the form of cash.
Mr. Hatch was granted a sign-on phantom unit award with a grant date fair value of $250,070 under the provisions of our Long-Term Incentive Plan and therefore did not participate in the 2015 Phantom Unit Program. Due to the interim nature of his position in 2015, Mr. Hatch's phantom units were granted subject to a time-vesting requirement, whereby the units fully vest on March 31, 2016.
For further description of this compensation program, please see "Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table — Description of Long-Term Incentive Plan."

Health and Welfare Benefits

We offer a variety of health and welfare benefits to all eligible employees of our general partner. These benefits are consistent with the types of benefits provided by our peer group and provided so as to ensure that we are able to maintain a competitive position in terms of attracting and retaining executive officers and other employees. In addition, the health and welfare programs are intended to protect employees against catastrophic loss and encourage a healthy lifestyle. The named executive officers generally are eligible for the same benefit programs on the same basis as the rest of our employees. Our health and welfare programs include medical, pharmacy, dental, life and accidental death and dismemberment insurance coverages. In addition, all employees working over 30 hours per week are eligible for long-term disability coverage. Long-term disability coverage benefits specific to the named executive officers provide for a compensation allowance, which is grossed up for the payment of taxes, to allow them to purchase long-term disability coverage on an after-tax basis at no net cost to them. As structured, these long-term disability benefits will pay 60% of monthly earnings, as defined by the policy, up to a maximum of $15,000 per month during a period of continuing disability up to normal retirement age, as defined by the policy. Executive officers and other key employees are also eligible to obtain annual executive physical examinations which are paid for by Calumet. Decisions made with respect to this compensation element do not significantly factor into or affect decisions made with respect to other compensation elements.

Retirement Benefits

We provide the Calumet GP, LLC Retirement Savings Plan (the "401(k) Plan") to assist our eligible officers and employees in providing for their retirement. Named executive officers participate in the same retirement savings plan as other eligible employees subject to ERISA limits. We match 100% of each 1% of eligible compensation contribution by the participant up to 4% and 50% of each additional 1% of eligible compensation contribution up to 6%, for a maximum contribution by us of 5% of eligible compensation contributions per participant. These contributions are provided as a reward for prior contributions and future efforts toward our success and growth.

Perquisites

We provide executive officers with perquisites and other personal benefits that we believe are reasonable and consistent with our overall compensation programs and philosophy. These benefits are provided in order to enable us to attract and retain these executives. Decisions made with respect to this compensation element do not significantly factor into or affect decisions made with respect to other compensation elements.
All named executive officers are provided with all, or certain of, the following benefits as a supplement to their other compensation:

- Use of Company Vehicles: In order to assist them in conducting our daily affairs, we provide each named executive officer with a company vehicle that may be used for personal use as well as business use. Personal use of a company vehicle is treated as taxable compensation to the named executive officer.
- Executive Physical Program: Generally on an annual basis, we pay for a complete and professional personal physical exam for each named executive officer appropriate for his age to improve his health and productivity.
- Club Memberships: We pay club membership fees for a certain named executive officer. Although such club memberships may be used for personal purposes in addition to business entertainment purposes, each named executive officer having such a membership is responsible for the reimbursement to us or direct payment for any

incremental costs above the base membership fees associated with his personal use of such membership.

- Spousal and Family Travel: On an occasional basis, we pay expenses related to travel of the spouses or certain family members of our named executive officers in order to accompany the named executive officer to business-related events.
- Long-Term Disability Insurance: We provide compensation to allow each named executive officer to purchase long-term disability insurance on an after-tax basis at no net cost to him.

Table of Contents

- Legal Expenses: On an occasional basis, we pay legal expenses related to the negotiation of employment agreements for our named executive officers.
- Use of Company Aircraft: On an occasional basis, our named executive officers may be eligible to use a leased aircraft for personal use and the incremental cost to us is treated as and reflected in the tables below as compensation to the applicable officer for purposes of these disclosures. The items that we use to determine the incremental cost to us of these flights include the variable costs for personal use of aircraft that were charged to us by the vendor that operates the leased aircraft for contracted hourly costs, fuel charges, and taxes.
- Commuting and Living Expenses: In order for us to attract top executive talent, we must not be limited to those individuals residing in the Indianapolis metropolitan area and in some cases must be willing to offer payment or reimbursement for an agreed upon amount of relocation, commuting, temporary housing and other related costs.

The compensation committee periodically reviews the perquisite program to determine if adjustments are appropriate and noted the addition of payment of legal expenses was appropriate.

Other Compensation Related Matters

Former Executive Compensation

In March 2015, we entered into a severance and consulting agreement with Ms. Straumins in connection with her resignation. The terms of the agreement are described under "Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards in Fiscal 2015 Table."

Clawback Policy

The Long-Term Incentive Plan was last amended and restated on December 10, 2015. This amendment included a new provision that addresses the potential need to recover awards granted under that plan. To the extent that applicable laws or listing standards would require it, or otherwise as determined appropriate by us, all awards granted under the Long-Term Incentive Plan shall be subject to clawback, forfeiture, repurchase or recoupment, as appropriate.

Tax Implications of Executive Compensation

Because we are not an entity taxable as a corporation, many of the tax issues associated with executive compensation that face publicly traded corporations do not directly affect us. Internal Revenue Code Section 409A ("Section 409A") provides that amounts deferred under nonqualified deferred compensation plans are includible in a participant's income when vested, unless certain requirements are met. If these requirements are not met, participants are also subject to an additional income tax and interest. All of our awards under our Long-Term Incentive Plan, severance arrangements and other nonqualified deferred compensation plans presently meet these requirements. As a result, employees will be taxed when the deferred compensation is actually paid to them. We will be entitled to a tax deduction at that time.

Executive Ownership of Units

While we have not adopted any security ownership requirements or policies for our executives, our executive compensation programs foster the enhancement of executives' equity ownership through long-term, unit-based awards under the Long-Term Incentive Plan. Further, in 2006 several executives purchased a significant number of our common units as participants in a directed unit program in conjunction with our initial public offering. For a listing of security ownership by our named executive officers, refer to Item 12 "Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters."

The board of directors has adopted the Insider Trading Policy of Calumet GP, LLC and Calumet Specialty Products Partners, L.P. (the "Insider Trading Policy"), which provides guidelines to employees, officers and directors with respect to transactions in our securities. Pursuant to Calumet's Insider Trading Policy, all executive officers and directors must confer with our Chief Financial Officer before effecting any put or call options for our securities. Further, the Insider Trading Policy states that we strongly discourage all such transactions by officers, directors and all other employees and consultants. The Insider Trading Policy is available on our website at www.calumetspecialty.com or a copy will be provided at no cost to unitholders upon their written request to: Investor Relations, Calumet Specialty Products Partners, L.P., 2780 Waterfront Parkway East Drive, Suite 200, Indianapolis, Indiana, 46214.

Employment Agreements

We have entered into employment agreements with F. William Grube, executive vice chairman (former chief executive officer and vice chairman of the board), William H. Hatch, our 2015 interim chief executive officer, and R. Patrick Murray, II, executive vice president and chief financial officer, to ensure they will perform their roles for an extended period of time given their position and value to us. For a discussion of the material terms of the employment agreements, please refer to "Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table — Description of Employment Agreements."

Table of Contents

Under these employment agreements, the named executive officers are entitled to receive severance compensation if their employment is terminated under certain conditions, such as termination by the named executive officer for “good reason” or by us without “cause,” each as defined in the agreements and further described in “Potential Payments Upon Termination or Change in Control.”

Our employment agreements with the named executive officers and the related severance provisions are designed to meet the following objectives:

- Change in Control: In certain scenarios, the potential for merger or being acquired may be in the best interests of our unitholders. We provide the potential for severance compensation to the named executive officers in the event of a change in control transaction to promote their ability to act in the best interests of our unitholders even though their employment could be terminated as a result of the transaction.
- Termination without Cause: We believe severance compensation in such a scenario is appropriate because the named executive officers are bound by confidentiality, nonsolicitation and noncompetition provisions covering one year after termination and because we and the named executive officer have mutually agreed to a severance package that is in place prior to any termination event. This provides us with more flexibility to make a change in this executive position if such a change is in our and our unitholders’ best interests.

The salary multiple of the change of control benefits, use of the single or double trigger change of control benefits and the amount of the severance payout were determined through negotiations with each named executive officer at the time that we entered into the employment agreements. Relative to the overall value to us, the compensation committee believes these potential benefits are reasonable.

Report of the Compensation Committee for the Year Ended December 31, 2015

The compensation committee of our general partner has reviewed and discussed our Compensation Discussion and Analysis with management. Based upon such review, the related discussion with management and such other matters deemed relevant and appropriate by the compensation committee, the compensation committee has recommended to the board of directors that our Compensation Discussion and Analysis be included in the Company’s Annual Report on Form 10-K.

Members of the Compensation Committee:
Fred M. Fehsenfeld, Jr., Chairman
F. William Grube

Table of Contents

Summary Compensation Table

The following table sets forth certain compensation information of our named executive officers for the years ended December 31, 2015, 2014 and 2013:

Summary Compensation Table for 2015

Name and Principal Position	Year	Salary	Bonus (5)	Unit Awards (6)	Non-Equity Incentive Plan Compensation (7)	All Other Compensation (8)	Total
F. William Grube (1)	2015	$454,363	$—	$574,253	$641,351	$70,323	$1,740,290
Executive Vice Chairman and Former	2014	$441,129	$—	$393,900	$302,184	$89,918	$1,227,131
Chief Executive Officer	2013	$428,281	$—	$68,711	$—	$6,098	$503,090
William H. Hatch (2) Interim Chief Executive Officer	2015	$375,000	$187,500	$250,070	$—	$386,006	$1,011,076
R. Patrick Murray, II	2015	$339,488	$—	$423,072	$431,280	$47,865	$1,241,705
Executive Vice President and Chief	2014	$329,600	$—	$269,815	$165,769	$87,200	$852,384
Financial Officer	2013	$320,000	$—	$52,641	$—	$18,263	$390,904
William A. Anderson	2015	$312,626	$—	$338,400	$441,284	$60,633	$1,152,943
Executive Vice	2014	$279,130	$—	$217,584	$155,984	$79,048	$731,746
President — Sales	2013	$279,130	$—	$—	$—	$15,741	$294,871
Edward F. Juno (3) Executive Vice President — Fuels Operations	2015	$251,331	$—	$365,313	$212,133	$27,226	$856,003
Jennifer G. Straumins	2015	$92,829	$—	$3,590	$—	$829,467	$925,886
(4)	2014	$360,500	$—	$233,857	$201,456	$92,098	$887,911
Former Executive Vice President - Strategy and Development	2013	$350,000	$—	$39,030	$—	$17,483	$406,513

(1) Mr. Grube was appointed executive vice chairman effective April 1, 2015.

(2) Mr. Hatch was appointed interim chief executive officer effective April 1, 2015 and transitioned to executive advisor on January 1, 2016.

(3) Mr. Juno's employment with us commenced December 2012. He was appointed executive vice president — fuels operations effective March 23, 2015, and was not a named executive officer prior to 2015.

(4) Ms. Straumins resigned effective March 31, 2015.

(5) Mr. Hatch was eligible to receive a quarterly bonus of up to $62,500 based on individual performance in accomplishing certain key goals/milestones (e.g., successful attainment of major capital projects, achievement of certain operational and safety metrics, etc.) monitored by the board of directors. The performance metrics reviewed by the board of directors were used as guidelines rather than as formulaic requirements for the determination of the payment, therefore we have reported it as a “Bonus” rather than a “Non-Equity Incentive Plan Compensation” award.

(6)

The amounts include the aggregate grant date fair value of (i) phantom unit awards made in connection with each executive officer's election to defer a portion of his cash incentive plan award into our Deferred Compensation Plan, (ii) discretionary matching phantom unit awards granted during the 2015 fiscal year related to the 2014 fiscal year, (iii) phantom units to reward services provided during the fiscal year and the number of which is determined based on our level of Distributable Cash Flow during the fiscal year, excluding the effect of estimated forfeitures and (iv) DERs granted in the form of phantom units with respect to phantom units credited to the Deferred Compensation Plan accounts. The amounts exclude discretionary matching contributions made in the form of phantom units granted in 2016 to our named executive officers based on their individual elections to defer all or a portion of their cash award under the Cash Incentive Plan related to the 2015 fiscal year into the Deferred Compensation Plan. These amounts will be reported in the Summary Compensation Table in 2016. The amounts reflect the aggregate grant date fair value computed in accordance with FASB ASC Topic 718. See Note 11 to our

Table of Contents

consolidated financial statements for the fiscal year ending December 31, 2015 for a discussion of the assumptions used to determine the FASB ASC Topic 718 value of the awards.

(7) Represents amounts earned under our Cash Incentive Plan and not deferred into the Deferred Compensation Plan. Please read "Compensation Discussion and Analysis — Elements of Executive Compensation — Short-Term Cash Awards" for further details. Based on the timing of Ms. Straumins' resignation, she forfeited her award under the plan for fiscal 2015.

(8) The following table provides the aggregate "All Other Compensation" information for each of the named executive officers, except that it excludes perquisites or other personal benefits received by Messrs. Murray and Juno in 2015, as such amounts for these named executive officers were less than $10,000 in aggregate:

	F. William Grube	William H. Hatch	R. Patrick Murray, II	William A. Anderson	Edward F. Juno	Jennifer G. Straumins
401(k) Plan Matching Contributions	$7,950	$—	$13,250	$13,250	$13,250	$3,649
DERs	49,937	12,494	33,291	33,291	12,947	11,097
Commuting and Living Expenses [a]	—	371,602	—	—	—	—
Vehicle	8,978	—	—			