Calumet Specialty Products Partners, L.P.
Form 10-K
February 22, 2011

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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, 2010**
	OR
o	**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	**37-1516132**
(State or Other Jurisdiction of Incorporation or Organization)	*(I.R.S. Employer Identification Number)*

2780 Waterfront Pkwy E. 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

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 o No þ

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 o 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 o

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 o No o

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. o

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

Large accelerated filer o	Accelerated filer þ	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 o No þ

The aggregate market value of the common units held by non-affiliates of the registrant (treating all executive officers and directors of the registrant and holders of 10% or more of the common units outstanding, for this purpose, as if they may be affiliates of the registrant) was approximately $283.2 million on June 30, 2010, based on $17.68 per unit, the closing price of the common units as reported on the NASDAQ Global Select Market on such date.

On February 18, 2011, there were 35,279,778 common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE
NONE.

CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.
FORM 10-K 2010 ANNUAL REPORT

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FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K (this Annual Report) includes certain forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These statements can be identified by the use of forward-looking terminology including may, believe, expect, anticipate, estimate, continue, or other similar words. The statements regarding (i) estimated capital expenditures as a result of the required audits or required operational changes included in our settlement with the Louisiana Department of Environmental Quality (LDEQ) or other environmental and regulatory liabilities, (ii) our anticipated levels of use of derivatives to mitigate our exposure to crude oil price changes and fuel products price changes, and (iii) future compliance with our debt covenants, as well as other matters discussed in this Annual Report that are not purely historical data, are forward-looking statements. These statements discuss future expectations or state other forward-looking information and involve risks and uncertainties. When considering these forward-looking statements, unitholders should keep in mind the risk factors and other cautionary statements included in this Annual Report. The risk factors and other factors noted throughout this Annual Report could cause our actual results to differ materially from those contained in any forward-looking statement. These factors include, but are not limited to:

- the overall demand for specialty hydrocarbon products, fuels and other refined products;
- our ability to produce specialty products and fuels that meet our customers unique and precise specifications;
- the impact of fluctuations and rapid increases or decreases in crude oil and crack spread prices, including the resulting impact on our liquidity;
- the results of our hedging and other risk management activities;
- our ability to comply with financial covenants contained in our credit agreements;
- the availability of, and our ability to consummate, acquisition or combination opportunities;
- labor relations;
- our access to capital to fund expansions, acquisitions and our working capital needs and our ability to obtain debt or equity financing on satisfactory terms;
- successful integration and future performance of acquired assets, businesses or third-party product supply and processing relationships;
- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;
- maintenance of our credit ratings and ability to receive open credit lines from our suppliers;
- demand for various grades of crude oil and resulting changes in pricing conditions;
- fluctuations in refinery capacity;
- the effects of competition;
- continued creditworthiness of, and performance by, counterparties;

the impact of current and future laws, rulings and governmental regulations, including guidance related to the Dodd-Frank Wall Street Reform and Consumer Protection Act;

shortages or cost increases of power supplies, natural gas, materials or labor;

hurricane or other weather interference with business operations;

fluctuations in the debt and equity markets;

accidents or other unscheduled shutdowns; and

general economic, market or business conditions.

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Other factors described herein, or factors that are unknown or unpredictable, could also have a material adverse effect on future results. Our forward-looking statements are not guarantees of future performance, and actual results and future performance may differ materially from those suggested in any forward-looking statement. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this Annual Report. Please read Item 1A Risk Factors and Item 7A Quantitative and Qualitative Disclosures About Market Risk. We will not update these statements unless securities laws require us to do so.

All subsequent written and oral forward-looking statements attributable to us or to persons acting on our behalf are expressly qualified in their entirety by the foregoing. We undertake no obligation to publicly release the results of any revisions to any such forward-looking statements that may be made to reflect events or circumstances after the date of this report or to reflect the occurrence of unanticipated events.

References in this Annual Report to Calumet Specialty Products Partners, L.P., the Company, we, our, us or like terms, when used in a historical context prior to January 31, 2006, refer to the assets and liabilities of Calumet Lubricants Co., Limited Partnership and its subsidiaries of which substantially all such assets and liabilities were contributed to Calumet Specialty Products Partners, L.P. and its subsidiaries upon the completion of our initial public offering. When used in the present tense or prospectively, those 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. The results of operations for the year ended December 31, 2006 for the Company include the results of operations of the Predecessor for the period of January 1, 2006 through January 31, 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.

PART I

Items 1 and 2. Business and Properties

Overview

We are a Delaware limited partnership formed on September 27, 2005 and are a leading independent producer of high-quality, specialty hydrocarbon products in North America. We own plants located in Princeton, Louisiana (Princeton); Cotton Valley, Louisiana (Cotton Valley); Shreveport, Louisiana (Shreveport); Karns City, Pennsylvania (Karns City) and Dickinson, Texas (Dickinson) and a terminal located in Burnham, Illinois (Burnham). Our business is organized into two segments: specialty products and fuel products. In our specialty products segment, we process crude oil and other feedstocks into a wide variety of customized lubricating oils, white mineral oils, solvents, petrolatums and waxes. We also have contractual arrangements with LyondellBasell and other third parties which provide us additional volumes of finished products for our specialty products segment. Our specialty products are sold to domestic and international customers who purchase them primarily as raw material components for basic industrial, consumer and automotive goods. In our fuel products segment, we process crude oil into a variety of fuel and fuel-related products including gasoline, diesel and jet fuel. In connection with our production of specialty products and fuel products, we also produce asphalt and a limited number of other by-products. For the year ended December 31, 2010, approximately 64.3% of our sales and 94.3% of our gross profit were generated from our specialty products segment and approximately 35.7% of our sales and 5.7% of our gross profit were generated from our fuel products segment.

Our Assets

Our operating assets and contractual agreements consist of our:

Princeton Refinery. Our Princeton refinery, located in northwest Louisiana and acquired in 1990, produces specialty lubricating oils, including process oils, base oils, transformer oils and refrigeration oils that are used in a variety of industrial and automotive applications. The Princeton refinery has aggregate crude oil throughput capacity of approximately 10,000 barrels per day (bpd).

Cotton Valley Refinery. Our Cotton Valley refinery, located in northwest Louisiana and acquired in 1995, produces specialty solvents that are used principally in the manufacture of paints, cleaners, automotive products and drilling fluids. The Cotton Valley refinery has aggregate crude oil throughput capacity of approximately 13,500 bpd.

Shreveport Refinery. Our Shreveport refinery, located in northwest Louisiana and acquired in 2001, produces specialty lubricating oils and waxes, as well as fuel products such as gasoline, diesel and jet fuel. The Shreveport refinery has aggregate crude oil throughput capacity of approximately 60,000 bpd.

Karns City Facility. Our Karns City facility, located in western Pennsylvania and acquired in 2008, produces white mineral oils, petrolatums, solvents, gelled hydrocarbons, cable fillers and natural petroleum sulfonates. The Karns City facility has aggregate feedstock throughput capacity of approximately 5,500 bpd.

Dickinson Facility. Our Dickinson facility, located in southeastern Texas and acquired in 2008, produces white mineral oils, compressor lubricants and natural petroleum sulfonates. The Dickinson facility currently has aggregate feedstock throughput capacity of approximately 1,300 bpd.

LyondellBasell Agreements. Effective November 4, 2009, we entered into agreements (the LyondellBasell Agreements) with Houston Refining LP, a wholly-owned subsidiary of LyondellBasell (Houston Refining), to form a long-term specialty products affiliation. The initial term of the LyondellBasell Agreements expires on October 31, 2014 after which it is automatically extended for additional one-year terms until either party terminates with 24 months notice. Under the terms of the LyondellBasell Agreements, (i) we are required to purchase at least a minimum volume of 3,100 bpd of naphthenic lubricating oils produced at Houston Refining s Houston, Texas refinery, and we have a right of first refusal to purchase any additional naphthenic lubricating oils produced at the refinery, and (ii) Houston Refining is required to process a minimum of approximately 800 bpd of white mineral oil for us at its Houston, Texas refinery, which supplements the white mineral oil production at our

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Karns City and Dickinson facilities. LyondellBasell has also granted us rights to use certain registered trademarks and tradenames, including Tufflo, Duoprime, Duotreat, Crystex, Ideal and Aquamarine.

Distribution and Logistics Assets. We own and operate a terminal in Burnham, Illinois with a storage capacity of approximately 150,000 barrels that facilitates the distribution of products in the Upper Midwest and East Coast regions of the United States and in Canada. In addition, we lease approximately 1,850 railcars used to receive crude oil or distribute our products throughout the United States and Canada. We also have approximately 6.0 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 businesses and assets that generate stable cash flows. Approximately 64.3% of our sales and 94.3% of our gross profit for 2010 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 highly specialized products. 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 and by maintaining a shorter-term crude oil hedging program. Also, in our fuel products segment, which accounted for 35.7% of our sales and 5.7% of our gross profit in 2010, we seek to mitigate our exposure to fuel products margin volatility by maintaining a longer-term fuel products hedging program. In 2010, we realized $11.0 million of gains from this program. In summary, we believe the diversity of our 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 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. 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. For example, in late 2004 at the Shreveport refinery we recommissioned certain of its previously idled fuels production units, refurbished existing fuels production units, converted existing units to improve gasoline blending profitability and expanded capacity to approximately 42,000 bpd to increase lubricating oil and fuels production. Also, in December 2006 we commenced construction of an expansion project at our Shreveport refinery that was completed and operational in May 2008 to increase its aggregate crude oil throughput capacity from 42,000 bpd to approximately 60,000 bpd. In 2009 and 2010, we focused on optimizing current operations through energy savings initiatives, product quality enhancements, and product yield improvements. We intend to continue this approach with our existing assets in 2011.

Pursue strategic and complementary acquisitions. Since 1990, 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 our specialty products segment. In addition, we may pursue selected acquisitions in new geographic or product areas to the extent we perceive similar opportunities. For example, effective November 4, 2009, we entered into sales and processing agreements with Houston Refining related to naphthenic lubricating and white mineral oils.

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 over 1,000 specialty products. We believe that our ability to provide our customers with a more diverse selection of products than our competitors generally 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 over 2,600 active accounts and we are continually seeking new customers. No single specialty products customer accounted for more than 10% of our consolidated sales in each of the three years ended December 31, 2010, 2009 and 2008.

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 Shreveport and Cotton Valley refineries have the capability to make ultra low sulfur diesel and all of the Shreveport refinery s gasoline production meets federally mandated low sulfur standards and newly implemented Mobile Source Air Toxic Rule II standards (MSAT II standards) set by the U.S. Environmental Protection Agency (EPA) requiring the reduction of benzene levels in gasoline and effective January 1, 2011. 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. Our senior management team, the majority of whom have been working together since 1990, has an average of approximately 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.

Partnership Structure and Management

Calumet Specialty Products Partners, L.P. is a Delaware limited partnership formed on September 27, 2005. The general partner of the Company is Calumet GP, LLC, a Delaware limited liability company. As of February 18, 2011, the Company had 35,279,778 common units and 719,995 general partner units outstanding. The general partner owns 2% of the Company. Our general partner has sole responsibility for conducting our business and managing our operations. For more information about our general partner s board of directors, executive officers and other management, please read Item 10 Directors, Executive Officers of Our General Partner and Corporate Governance.

Our Operating Assets and Contractual Arrangements

General

We own and operate facilities in northwest Louisiana, which consist of the Princeton refinery, the Cotton Valley refinery and the Shreveport refinery, facilities in Karns City, Pennsylvania and Dickinson, Texas, and a terminal in Burnham, Illinois. We also have contractual arrangements with LyondellBasell and other third parties which provide us additional volumes of finished products for our specialty products segment.

The following table sets forth information about our combined operations. Production volume differs from sales volume due to changes in inventory. The following table does not include volumes under the LyondellBasell Agreements in 2008 and for the majority of 2009, as such agreements were not deemed effective until November 4, 2009.

	Year Ended December 31,		
	2010	2009	2008
		(In bpd)	
Total sales volume (1)	55,668	57,086	56,232
Total feedstock runs (2)	55,957	60,081	56,243
Facility production:			
Specialty products:			
Lubricating oils	13,697	11,681	12,462
Solvents	9,347	7,749	8,130
Waxes	1,220	1,049	1,736
Fuels	1,050	853	1,208
Asphalt and other by-products	6,907	7,574	6,623
Total	32,221	28,906	30,159
Fuel products:			
Gasoline	8,754	9,892	8,476
Diesel	10,800	12,796	10,407
Jet fuel	5,004	6,709	5,918
By-products	535	489	370
Total	25,093	29,886	25,171
Total facility production (3)	57,314	58,792	55,330

(1) Total sales volume includes sales from the production at our facilities and certain third-party facilities pursuant to supply and/or processing agreements, and sales of inventories.

(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 decrease in feedstock runs in 2010 compared to 2009 is due primarily to our decision to reduce crude oil run rates at our Shreveport refinery during the entire first quarter of 2010 because of the poor economics of running additional barrels, the failure of an environmental operating unit during the first quarter of 2010 and scheduled turnarounds completed in the second and fourth quarters related to various operating units at our Shreveport refinery. These decreases were partially offset by higher year-long throughput rates at our Cotton Valley refinery and the addition of volumes under the LyondellBasell Agreements.

The increase in feedstock runs in 2009 compared to 2008 is due primarily to the Shreveport refinery expansion project placed in service in May 2008, resulting in a full year of increased production in 2009 compared to 2008, and the addition of volumes under the LyondellBasell Agreements in 2009. Partially offsetting these increases were lower overall feedstock runs at our other facilities in 2009 compared to 2008 due to general economic conditions.

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

The increase in the production of specialty products in 2010 compared to 2009 is primarily the result of the addition of volumes under the LyondellBasell Agreements and higher throughput rates at our Cotton Valley refinery.

The reduction in production of fuel products in 2010 compared to 2009 is due primarily to reduced feedstock runs at our Shreveport refinery as discussed in footnote 2 of this table.

The change in production mix to higher fuel products production in 2009 compared to 2008 is due primarily to reduced demand for certain specialty products due to overall economic conditions.

Set forth below is information regarding sales of our principal products by segment.

	Year Ended December 31,		
	2010	2009	2008
	(In thousands)		
Sales of specialty products:			
Lubricating oils	$ 759,701	$ 500,938	$ 841,225
Solvents	396,894	260,185	419,831
Waxes	124,964	97,658	142,525
Fuels	5,507	8,951	30,389
Asphalt and other by-products	121,806	103,488	144,065
Total	1,408,872	971,220	1,578,035
Sales of fuel products:			
Gasoline	304,544	317,435	332,669
Diesel	330,756	372,359	379,739
Jet fuel	135,796	167,638	186,675
By-products	10,784	17,948	11,876
Total	781,880	875,380	910,959
Consolidated sales	$ 2,190,752	$ 1,846,600	$ 2,488,994

Princeton Refinery

The Princeton refinery, located on a 208-acre site in Princeton, Louisiana, has aggregate crude oil throughput capacity of 10,000 bpd and is currently processing naphthenic crude oil into lubricating oils, asphalt and feedstock for the Shreveport refinery for further processing into ultra low sulfur diesel. The asphalt may be processed or blended for coating and roofing applications at the Princeton refinery or transported to the Shreveport refinery for processing into bright stock.

The Princeton refinery currently 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,		
	2010	2009	2008
		(In bpd)	
Crude oil throughput capacity	10,000	10,000	10,000
Total feedstock runs (1)	6,096	6,076	6,516
Total refinery production (1)	6,138	5,999	6,551

(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 production of finished products and volume loss.

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 applications such as coatings and road paving.

The Princeton refinery receives crude oil via tank truck, railcar and pipeline. Its crude oil supply primarily originates from east Texas and north Louisiana and is purchased through Legacy Resources Co., L.P. (Legacy Resources), a related party. See Item 13 Certain Relationships and Related Transactions and Director Independence Crude Oil Purchases for additional information regarding our crude oil purchases from Legacy Resources. The Princeton refinery ships its finished products throughout the country by both truck and railcar service.

Cotton Valley Refinery

The Cotton Valley refinery, located on a 77-acre site in Cotton Valley, Louisiana, has aggregate crude oil throughput capacity of 13,500 bpd, hydrotreating capacity of 5,100 bpd and is currently processing crude oil into solvents, fuel feedstocks and residual fuel oil. The residual fuel oil is an important feedstock for specialty products at our Shreveport refinery. We believe the Cotton Valley refinery produces the most complete, single-facility line of paraffinic solvents in the United States.

The Cotton Valley refinery currently 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. The Cotton Valley refinery also has a utility fractionator for batch processing of narrow distillation range specialty solvents. 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,		
	2010	2009	2008
		(In bpd)	
Crude oil throughput capacity	13,500	13,500	13,500
Total feedstock runs (1) (2)	5,510	5,466	6,175
Total refinery production (2) (3)	7,229	6,455	6,757

(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 production of finished products and volume loss.

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

The Cotton Valley refinery configuration is flexible, which allows us to respond to market changes and customer demands by modifying its product mix. The reconfigured fractionation train also allows the refinery to satisfy demand fluctuations efficiently without large product inventory requirements.

The Cotton Valley refinery receives crude oil via truck and through a pipeline system operated by a subsidiary of Plains All American Pipeline, L.P. (Plains). The Cotton Valley refinery s feedstock is primarily low sulfur, 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.

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Shreveport Refinery

The Shreveport refinery, located on a 240-acre site in Shreveport, Louisiana, currently has aggregate crude oil throughput capacity of 60,000 bpd subsequent to the completion of a major expansion project in May 2008 and is currently processing paraffinic crude oil and associated feedstocks into fuel products, paraffinic lubricating oils, waxes, residuals, and by-products.

The Shreveport refinery consists of 16 major processing units, 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, added a second reactor to the high pressure hydrotreater, resumed production of gasoline, diesel and other fuel products at the refinery, and added both 18,000 bpd of crude oil throughput capacity and the capability to run up to 25,000 bpd of sour crude oil with the expansion project completed in May 2008. The following table sets forth historical information about production at our Shreveport refinery.

	Shreveport Refinery Year Ended December 31,		
	2010	**2009**	**2008**
		(In bpd)	
Crude oil throughput capacity	60,000	60,000	60,000
Total feedstock runs (1) (2)	36,409	43,639	37,096
Total refinery production (2) (3)	36,395	43,467	35,566

(1) Total feedstock runs represents 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 refinery. The decrease in feedstock runs in 2010 compared to 2009 is due primarily to our decision to reduce crude oil run rates at our facilities during the entire first quarter of 2010 because of the poor economics of running additional barrels, the failure of an environmental operating unit during the first quarter of 2010 and scheduled turnarounds completed in the second and fourth quarters related to various operating units at our Shreveport refinery. The increase in feedstock runs in 2009 compared to 2008 is due primarily to the Shreveport refinery expansion project placed in service in May 2008, resulting in a full year of increased production in 2009 compared to 2008.

(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 refinery 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 currently makes jet fuel and ultra low sulfur diesel and all of its gasoline production currently meets MSAT II standards.

The Shreveport refinery receives crude oil via tank truck, railcar and common carrier pipeline systems that are operated by subsidiaries of Plains and Exxon Mobil Corporation (ExxonMobil) and are 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. The ExxonMobil pipeline system delivers domestic crude oil supplies from south Louisiana and foreign crude oil supplies from the Louisiana Offshore Oil Port (LOOP) or other crude oil terminals. Crude oil is also purchased through Legacy Resources and various other counterparties, including local producers who deliver crude oil to the Shreveport refinery via tank truck.

See Item 13 Certain Relationships and Related Transactions and Director Independence Crude Oil Purchases for additional information regarding our crude oil purchases from Legacy Resources. The Shreveport refinery ships its finished products throughout the country by both truck and railcar service.

The Shreveport refinery has direct pipeline access to the Enterprise Products Partners L.P. pipeline (TEPPCO pipeline), on which it can ship all grades of gasoline, diesel and jet fuel. The refinery also 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 country through both truck and railcar service.

Karns City Facility

The Karns City facility, located on a 225-acre site in Karns City, Pennsylvania, currently has aggregate base oil throughput capacity of 5,500 bpd and is currently processing 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, approximately 817,000 barrels of storage capacity in 250 tanks and related loading and unloading facilities and utilities. The facility receives its base oil feedstocks by railcar and truck under long-term supply agreements with various suppliers, the most significant of which is ConocoPhillips. Please read Crude Oil and Feedstock Supply for further discussion of the long-term supply agreements with ConocoPhillips.

Dickinson Facility

The Dickinson facility, located on a 28-acre site in Dickinson, Texas, currently has aggregate base oil throughput capacity of 1,300 bpd and is currently processing white mineral oils, compressor lubricants, and natural petroleum sulfonates. 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. The facility receives its base oil feedstocks by railcar and truck under long-term supply agreements with various suppliers, the most significant of which is ConocoPhillips. Please read Crude Oil and Feedstock Supply for further discussion of the long-term supply agreements with ConocoPhillips.

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

	Combined Karns City and Dickinson Facilities Year Ended December 31,		
	2010	2009	2008
		(in bpd)	
Feedstock throughput capacity (1)	6,800	6,800	6,800
Total feedstock runs (2)	5,051	4,595	6,456
Total production (3)	5,041	4,590	6,456

(1) Includes Karns City and Dickinson facilities only.

(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.

(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.

LyondellBasell Agreements

Effective November 4, 2009, we entered into the LyondellBasell Agreements with Houston Refining to form a long-term specialty products affiliation. The initial term of the LyondellBasell Agreements expires on October 31,

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2014 after which it is automatically extended for additional one-year terms until either party terminates with 24 months notice. Under the terms of the LyondellBasell Agreements, (i) we are required to purchase at least a minimum volume of 3,100 bpd of naphthenic lubricating oils produced at Houston Refining s Houston, Texas refinery, and we have a right of first refusal to purchase any additional naphthenic lubricating oils produced at the refinery, and (ii) Houston Refining is required to process a minimum of approximately 800 bpd of white mineral oil for us at its Houston, Texas refinery, which supplements the white mineral oil production at our Karns City and Dickinson facilities. LyondellBasell has also granted us rights to use certain registered trademarks and tradenames, including Tufflo, Duoprime, Duotreat, Crystex, Ideal and Aquamarine.

The following table sets forth the combined historical information about production under the LyondellBasell Agreements.

	Houston Refining Year Ended December 31,	
	2010	**2009**
	(in bpd)	
Feedstock throughput capacity (1)	4,500	4,500
Total production for the Company (2)	2,876	1,994

(1) Estimated total capacity of the naphthenic lubricating oil and white oil hydrotreating units at Houston Refining s Houston, Texas refinery.

(2) For 2009, represents the period from November 4, 2009 through December 31, 2009. Total production in both 2010 and 2009 did not meet anticipated levels as Houston Refining s Houston, Texas refinery experienced downtime due to various turnarounds and operational issues.

Burnham Terminal and Other Logistics Assets

We own and operate a terminal, located on an 11-acre site, in Burnham, Illinois. The Burnham terminal receives specialty products from our refineries and distributes them by truck to our customers in the Upper Midwest and East Coast regions of the United States and in Canada.

The terminal includes a tank farm with 67 tanks with aggregate lubricating oil, solvent and specialty product storage capacity of approximately 150,000 barrels as well as blending equipment. The Burnham terminal is complementary to our refineries and plays a key role in moving our products to the end-user market by providing the following services:

- distribution;
- blending to achieve specified products; and
- storage and inventory management.

We also lease a fleet of approximately 1,850 railcars from various lessors. This fleet enables us to receive crude oil and distribute various specialty products throughout the United States and Canada to and from each of our facilities.

Crude Oil and Feedstock Supply

We purchase crude oil from major oil companies, various gatherers and marketers in east Texas and north Louisiana and from Legacy Resources, an affiliate of our general partner. The Shreveport refinery also receives crude oil through the ExxonMobil pipeline system originating in St. James, Louisiana, which provides the refinery with access to domestic crude oils and foreign crude oils through the LOOP or other terminal locations.

In 2010, we purchased 58.1% of our crude oil supply through evergreen crude oil supply contracts, which are typically terminable on 30 days notice by either party, and 0.4% of our crude oil supply on the spot market. Legacy Resources supplied us with the remaining 41.5% of our crude oil in 2010. Refer to Item 13 Certain Relationships and Related Transactions and Director Independence Crude Oil Purchases for further information on our

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related party crude oil purchases. We also purchase foreign crude oil when its spot market price is attractive relative to the price of crude oil from domestic sources. We believe that adequate supplies of crude oil 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, the 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 the rising cost of crude oil. We use a hedging program to manage a portion of this commodity price risk. Please read Item 7A Quantitative and Qualitative Disclosures About Market Risk Commodity Price Risk Crude Oil Hedging Policy for a discussion of our crude oil hedging program.

We have various long-term supply agreements with ConocoPhillips, with remaining terms ranging from one to seven 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 feedstocks are available for these facilities.

Markets and Customers

We produce a full line of specialty products, including lubricating oils, solvents and waxes, as well as a variety of fuel products. Our customers purchase these products primarily as raw material components for basic industrial, consumer and automotive goods. The following table depicts the diversity of end-use applications for the products we produce:

Representative Sample of End Use Applications by Product[1]

Lubricating Oils 24%	Solvents 16%	Waxes 2%	Asphalt & Other 12%	Fuels & Fuel Related 46%
Hydraulic Oils	Waterless hand cleaners	Paraffin waxes	Roofing	Gasoline
Passenger car motor oils	Alkyd resin diluents	FDA compliant products	Paving	Diesel
Railroad engine oils	Automotive products	Candles		Jet fuel
Cutting oils	Calibration fluids	Adhesives		Fluid catalytic cracking feedstock
Compressor oils	Camping fuel	Crayons		Asphalt vacuum residuals
Rubber process oils	Charcoal lighter fluids	Floor care		Mixed butanes
Industrial lubricants		PVC		
Gear oils		Paint strippers		

Grease	Chemical processing	Skin & hair care
Automatic transmission fluid	Drilling fluids	Timber treatment
Animal feed dedusting	Printing inks	Waterproofing
Baby oils		Pharmaceuticals
Bakery pan oils		Cosmetics
Catalyst carriers		
Gelatin capsule lubricants		
Sunscreen		

(1) Based on the percentage of actual total production for the year ended December 31, 2010. We do not produce any of these end-use products.

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

Markets

Specialty Products. The specialty products market represents a small portion of the overall petroleum refining industry in the United States. Of the nearly 150 refineries currently in operation in the United States, 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 in:

- 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 (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 United States and Canada, we ship our specialty products via railcars, trucks and barges. In 2010, about 33.5% of our specialty products were shipped in our fleet of approximately 1,850 leased railcars, about 63.0% of our specialty products shipped in trucks owned and operated by several different third-party carriers and the remaining 3.5% were shipped via water transportation. For shipments outside of North America, which accounted for less than 10% of our consolidated sales in 2010, we ship railcars and trucks to several ports where the product is loaded on vessels for shipment to customers.

Fuel Products. We produce a variety of fuel and fuel-related products at our Shreveport refinery.

Fuel products produced at the Shreveport refinery can be sold locally or through the TEPPCO pipeline. Local sales are made from the TEPPCO terminal in Bossier City, Louisiana, which is located approximately 15 miles from the Shreveport refinery, as well as from our own refinery terminal. Any excess volumes are sold to marketers further up the TEPPCO pipeline.

During 2010, we sold gasoline, diesel and jet fuel into the Louisiana, Texas and Arkansas markets, and any excess volumes 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.

The Shreveport refinery has the capacity to produce about 9,000 bpd of commercial jet fuel that can be marketed to the Barksdale Air Force Base in Bossier City, Louisiana, sold as Jet-A locally or via the TEPPCO pipeline, or occasionally transferred to the Cotton Valley refinery to be processed further as a feedstock to produce solvents. Jet fuel sales volumes change as the margins between diesel and jet fuel change. We have a sales contract with the U.S. Department of Defense covering the Barksdale Air Force Base for approximately 5,200 bpd of jet fuel. This contract is effective until April 2011 and is bid annually.

Additionally, we produce a number of fuel-related products including fluid catalytic cracking (FCC) feedstock, asphalt vacuum residuals and mixed butanes.

Vacuum residuals are blended or processed further to make specialty 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. FCC feedstock is sold to other refiners as a feedstock for their FCC units to make fuel products. Butanes are primarily available in the summer months and are primarily sold to local marketers. If the butanes are not sold they are blended into our gasoline production.

Customers

Specialty Products. We have a diverse customer base for our specialty products, with approximately 2,600 active accounts. Most of our customers are long-term customers who use our products in specialty applications which require six months to two years to gain approval for use in their products. No single customer of our specialty products segment accounted for more that 10% of our consolidated sales in each of the three years ended December 31, 2010, 2009 and 2008.

Fuel Products. We have a diverse customer base for our fuel products, with approximately 90 active accounts. We are able to sell the majority of the fuel products we produce to the local markets of Louisiana, east Texas and Arkansas. We also have the ability to ship our fuel products to the Midwest region through the TEPPCO pipeline should the need arise. During the year ended December 31, 2008, one of our customers, Murphy Oil U.S.A., represented approximately 10.5% of consolidated sales due to rising gasoline and diesel prices and increased fuel products sales to this customer. No other fuel products segment customer represented 10% or greater of consolidated sales in each of the three years ended December 31, 2010, 2009 and 2008.

Competition

Competition in our markets is from a combination of large, integrated petroleum companies, independent refiners and wax production 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 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 competitor in producing naphthenic lubricating oils is Ergon Refining, Inc. We also compete with Cross Oil Refining and Marketing, Inc. and San Joaquin Refining Co., Inc.

Paraffinic Lubricating Oils. Our primary competitors in producing paraffinic lubricating oils include ExxonMobil, Motiva Enterprises, LLC, ConocoPhillips, Petro-Canada, Holly Corporation and Sonneborn Refined Products.

Paraffin Waxes. Our primary competitors in producing paraffin waxes include ExxonMobil and The International Group Inc.

Solvents. Our primary competitors in producing solvents include Citgo Petroleum Corporation, Exxon Chemical and ConocoPhillips.

Fuel Products. Our primary competitors in producing fuel products in the local markets in which we operate include Delek Refining, Ltd. and Lion Oil Company.

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

Environmental, Health and Safety Matters

We operate crude oil and specialty hydrocarbon refining and terminal operations, which are subject to stringent and complex federal, state, and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations can impair our operations that affect the environment in many ways, such as requiring the acquisition of permits to conduct regulated activities, restricting the manner in which the Company can release materials into the environment, requiring remedial activities or capital expenditures to mitigate pollution from former or current operations, and imposing substantial liabilities on us for pollution resulting from our operations. Certain environmental 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.

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Failure to comply with environmental laws and regulations may result in the triggering of administrative, civil and criminal measures, including the assessment of monetary penalties, the imposition of remedial obligations, and the issuance of injunctions limiting or prohibiting some or all of our operations. On occasion, we receive notices of violation, enforcement and other complaints from regulatory agencies alleging non-compliance with applicable environmental laws and regulations. In particular, the Louisiana Department of Environmental Quality (LDEQ) initiated enforcement actions in prior years for the following alleged violations: (i) a May 2001 notification received by the Cotton Valley refinery from the LDEQ regarding several alleged violations of various air emission regulations, as identified in the course of our Leak Detection and Repair program, and also for failure to submit various reports related to the facility s air emissions; (ii) a December 2002 notification received by the Cotton Valley refinery from the LDEQ regarding alleged violations for excess emissions, as identified in the LDEQ s file review of the Cotton Valley refinery; (iii) a December 2004 notification received by the Cotton Valley refinery from the LDEQ regarding alleged violations for the construction of a multi-tower pad and associated pump pads without a permit issued by the agency; and (iv) an August 2005 notification received by the Princeton refinery from the LDEQ regarding alleged violations of air emissions regulations, as identified by LDEQ following performance of a compliance review, due to excess emissions and failures to continuously monitor and record air emission levels. As further discussed below, on December 23, 2010, the Company entered into a settlement agreement with the LDEQ that consolidated the terms of its settlement of the aforementioned alleged violations with the Company s agreement to voluntarily participate in the LDEQ s Small Refinery and Single Site Refinery Initiative.

The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in environmental laws and regulations that result in more stringent and costly waste handling, storage, transport, disposal, or remediation requirements could have a material adverse effect on our operations and financial position. Moreover, in connection with accidental spills or releases associated with our operations, we cannot assure our unitholders that we will not incur substantial costs and liabilities as a result of such spills or releases, including those relating to claims for damage to property and persons. In the event of future increases in costs, we may be unable to pass on those increases to our customers. While we believe that we are in substantial compliance with existing environmental laws and regulations and that continued compliance with these requirements will not have a material adverse effect on us, there can be no assurance that our environmental compliance expenditures will not become material in the future.

Air

Our operations are subject to the federal Clean Air Act, as amended, and comparable state and local laws. The Clean Air Act 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 Clean Air Act, facilities that emit volatile organic compounds or nitrogen oxides face increasingly stringent regulations, including requirements to install various levels of control technology on sources of pollutants. In addition, the petroleum refining sector has come under stringent new EPA regulations, imposing 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. In addition, air permits are required for our refining and terminal operations that result in the emission of regulated air contaminants. These permits incorporate stringent control technology requirements and are subject to extensive review and periodic renewal. We believe that we are in substantial compliance with the Clean Air Act and similar state and local laws.

The Clean Air Act 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 December 1999, the EPA promulgated regulations limiting the sulfur content allowed in gasoline. These regulations required the phase-in of gasoline sulfur standards beginning in 2004, with special provisions for small refiners and for refiners serving those Western states exhibiting lesser air quality problems. Similarly, the EPA promulgated 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). The Shreveport refinery has implemented the sulfur standard with respect to produced gasoline and produces diesel meeting the ultra low sulfur standard.

Pursuant to the Energy Act of 2005 and 2007, the EPA has issued Renewable Fuels Standards II (RFS II) that implement mandates to blend renewable fuels into the petroleum fuels produced at our refineries. Under the RFS II, the EPA establishes a volume of renewable fuels that obligated refineries must blend into their finished petroleum fuels. In addition, we are required to meet the MSAT II regulations to reduce the benzene content of motor gasoline produced at our facilities. We have completed capital projects at our Shreveport refinery to comply with these fuel quality requirements.

On December 23, 2010, we entered into a settlement agreement with the LDEQ regarding the Company s voluntary participation in the LDEQ s Small Refinery and Single Site Refinery Initiative. This state initiative is patterned after the EPA s National Petroleum Refinery Initiative, which is a coordinated, integrated compliance and enforcement strategy to address federal Clean Air Act compliance issues at the nation s largest petroleum refineries. The agreement requires us to make a $1.0 million payment to the LDEQ, resulting in an additional $0.6 million expense recorded during the fourth quarter of 2010, and complete beneficial environmental programs and implement emissions reduction projects at our Shreveport, Cotton Valley and Princeton refineries. We estimate implementation of these requirements will result in approximately $11.0 million to $15.0 million of capital expenditures and expenditures related to additional personnel and environmental studies. This agreement also fully settles the aforementioned alleged environmental and permit violations at our Shreveport, Cotton Valley and Princeton refineries and stipulates that no further civil penalties over alleged past violations will be pursued by the LDEQ. The required investments are expected to include i) nitrogen oxide and sulfur dioxide emission reductions from heaters and boilers and New Source Performance Standards applicability of, and compliance for, sulfur recovery plants and flaring devices, iii) control of incidents related to acid gas flaring, tail gas and hydrocarbon flaring, iv) electrical reliability improvements to reduce flaring, v) flare refurbishment at the Shreveport refinery, vi) enhance the Benzene Waste National Emissions Standards for Hazardous Air Pollutants programs and the Leak Detection and Repair programs at the Company s three Louisiana refineries, and vii) Title V audits and targeted audits of certain regulatory compliance programs. During these negotiations with the LDEQ, we voluntarily initiated projects for certain of these requirements prior to our settlement with the LDEQ, and we currently anticipate completion of these projects over the next five years. 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 settlement to have a material adverse effect on our financial results or operations. We estimate that the total additional expenditures above our already planned levels will be approximately $1.0 million to $3.0 million. For additional information regarding the impact on our capital expenditures, please read Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Capital Expenditures. Before the terms of this settlement agreement are deemed final, the terms remain subject to public comment and the concurrence of the Louisiana Attorney General until the end of the first quarter of 2011.

Climate Change

In response to findings 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 climate changes, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that require a reduction in emissions of GHGs from motor vehicles and thereby triggered construction and operating permit review for GHG emissions from certain stationary sources. The EPA has published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration (PSD) and Title V permitting programs, pursuant to which these permitting programs have been tailored to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. Facilities required to obtain PSD permits for their GHG emissions also will 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, EPA entered a settlement agreement with environmental groups requiring the agency to propose by December 15, 2011 GHG New Source Performance Standards for refineries and to finalize these rules by November 15, 2012. In addition, the EPA published a final rule in October 2009 requiring the reporting of GHG emissions from specified large GHG emission sources in the United States, including petroleum refineries, on an annual basis beginning in 2011 for emissions occurring after January 1, 2010. These EPA policies and rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities.

In addition, from time to time Congress has actively considered legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions or major producers of fuels, such as petroleum refineries, to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. These allowances would be expected to escalate significantly in cost over time. The adoption of any legislation or regulations that requires reporting of GHGs or otherwise limits emissions of GHGs from our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the refined petroleum products that we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs 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 (RCRA), and comparable state laws, which impose requirements related to the handling, storage, treatment, and disposal of solid and 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 solid wastes, which are regulated under RCRA and state laws. We believe that we are in substantial compliance with the existing requirements of RCRA and similar state and local laws, 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 was 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.

Voluntary remediation of subsurface contamination is in process at each of our refinery sites. The remedial projects are being overseen by the appropriate state agencies. Based on current investigative and remedial activities, we believe that the 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. In connection with the remediation of groundwater impacts at our refinery sites, we incurred approximately $0.5 million of capital expenditures at the

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Cotton Valley refinery during 2010 and estimate that we will incur another $0.8 million of capital expenditures in 2011 at this refinery in connection with ongoing remedial activities.

Water

The Federal Water Pollution Control Act of 1972, as amended, also known as the 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 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. We believe that we are in substantial compliance with the requirements of the Clean Water Act and similar state laws.

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. We believe that we are in substantial compliance with OPA and similar state laws.

Health, Safety and Maintenance

We are subject to the requirements of the federal Occupational Safety and Health Act (OSHA) and comparable state occupational safety statutes. These laws and the implementing 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 available to employees and contractors and, where required, to state and local government authorities and to local residents. We provide all required information to employees and contractors on how to mitigate or protect against exposure to hazardous materials present in our operations. Also, we maintain safety, training, and maintenance programs as part of our ongoing efforts to ensure compliance with applicable laws and regulations. While the nature of our business may result in industrial accidents from time to time, we believe that we have operated in substantial compliance with OSHA and similar state laws, including general industry standards, recordkeeping and reporting, hazard communication and process safety management. We have implemented an internal program of inspection designed to monitor and enforce compliance with worker safety requirements as well as a quality system that meets the requirements of the ISO-9001-2000 Standard. The integrity of our ISO-9001-2000 Standard certification is maintained through surveillance audits by our registrar at regular intervals designed to ensure adherence to the standards. On April 30, 2010, we received certification to the ISO-9001-2008 Standard. Our compliance with applicable health and safety laws and regulations has required and continues to require substantial expenditures. Changes in 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.

During 2010, we completed studies to assess the adequacy of our process safety management practices at our Shreveport refinery with respect to certain consensus codes and standards. We expect to incur between $5.0 million and $8.0 million of capital expenditures in total during 2011, 2012 and 2013 to address OSHA process safety management compliance issues identified in these studies. We expect these capital expenditures will enhance equipment to maintain compliance with applicable consensus codes and standards.

Beginning in February 2010, OSHA conducted an inspection of the Shreveport refinery s process safety management program under OSHA s National Emphasis Program which is targeting all U.S. refineries for review. On August 19, 2010, OSHA issued a Citation and Notification of Penalty (the Citation) to us as a result of this inspection which included a proposed civil penalty amount of $0.2 million. We contested the Citation and associated penalty amount and agreed to a final penalty amount of $0.1 million, which was paid in January 2011.

The Cotton Valley refinery s process safety management program is currently undergoing inspection under OSHA s National Emphasis Program.

We perform preventive and normal maintenance on all of our refining and logistics assets and make repairs and replacements when necessary or appropriate. We also conduct inspections of these assets as required by law or regulation.

Other Environmental Item

We are indemnified by Shell Oil Company, as successor to Pennzoil-Quaker State Company and Atlas Processing Company, for specified environmental liabilities arising from operations of the Shreveport refinery prior to our acquisition of the facility. The indemnity is unlimited in amount and duration, but requires us to contribute up to $1.0 million of the first $5.0 million of indemnified costs for certain of the specified environmental liabilities.

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.

Seasonality

The operating results for the fuel products segment and 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 annual 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. 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 this seasonality.

Title to Properties

We own the following properties, which are pledged as collateral under our existing credit facilities as discussed in Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Debt and Credit Facilities.

	Acres	Location
Shreveport refinery	240	Shreveport, Louisiana
Princeton refinery	208	Princeton, Louisiana
Cotton Valley refinery	77	Cotton Valley, Louisiana
Burnham terminal	11	Burnham, Illinois
Karns City facility	225	Karns City, Pennsylvania
Dickinson facility	28	Dickinson, Texas

Office Facilities

In addition to our refineries and terminal discussed above, we occupy approximately 26,900 square feet of office space in Indianapolis, Indiana under a lease. We also lease but are not currently using approximately 14,500 square feet of office space in The Woodlands, Texas. 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. We expect that we will not renew our lease of office space in The Woodlands, Texas at its expiration on April 30, 2012 and are actively engaged in efforts to sublease this office space for the remainder of the lease term.

Employees

As of February 18, 2011, our general partner employs approximately 650 people who provide direct support to the Company s operations. Of these employees, approximately 360 are covered by collective bargaining agreements. Employees at the Princeton, Cotton Valley and Dickinson facilities are covered by separate collective bargaining agreements with the International Union of Operating Engineers. The Princeton facility s collective bargaining agreement expires on October 31, 2011. The Cotton Valley and Dickinson facilities collective bargaining agreements will both expire on March 31, 2013. Employees at the Shreveport refinery are covered by a collective bargaining agreement with the United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied-Industrial, and Service Workers International Union which expires on April 30, 2013. The Karns City facility employees are covered by a collective bargaining agreement with United Steel Workers that will expire on January 31, 2012. None of the employees at the Burnham terminal 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.

We make the following information available free of charge on our website:

- Annual Report on Form 10-K;
- Quarterly Reports on Form 10-Q;
- Current Reports on Form 8-K;
- Amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934;
- Charters for the Audit, Compensation and Conflicts Committees; and
- Code of Business Conduct and Ethics.

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. 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.

Item 1A. ***Risk Factors***

We may not have sufficient cash from operations to enable us to pay the minimum quarterly distribution following the establishment of cash reserves and payment of fees and expenses, including payments to our general partner.

We may not have sufficient available cash from operations each quarter to enable us to pay the minimum quarterly distribution. 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 and specialty products, or refined products, 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;
- the level of foreign and domestic production of crude oil and refined products;
- our ability to produce fuel and specialty products 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 credit facilities; and
- the amount of cash reserves established by our general partner for the proper conduct of our business.

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.

Our credit agreements contain operating and financial restrictions that may restrict our business and financing activities.

The operating and financial restrictions and covenants in our credit agreements 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. For example, our credit agreements restrict our ability to:

- pay distributions;

incur indebtedness;

grant liens;

make certain acquisitions and investments;

make capital expenditures above specified amounts;

redeem or prepay other debt or make other restricted payments;

enter into transactions with affiliates;

enter into a merger, consolidation or sale of assets; and

cease our crack spread hedging program.

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Our ability to comply with the covenants and restrictions contained in our credit agreements may be affected by events beyond our control. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired. If we violate any of the restrictions, covenants, ratios or tests in our credit agreements, a significant portion of our indebtedness may become immediately due and payable, our ability to make distributions may be inhibited and our lenders commitment to make further loans to us may terminate. We might not have, or be able to obtain, sufficient funds to make these accelerated payments. In addition, our obligations under our credit agreements are secured by substantially all of our assets and if we are unable to repay our indebtedness under our credit agreements, the lenders could seek to foreclose on our assets.

Our senior secured term loan credit agreement and revolving credit facility contain operating and financial restrictions similar to the above listed items. Financial covenants in the term loan credit agreement and the amended revolving credit facility agreement include a maximum consolidated leverage ratio of 3.75 to 1.00 and a minimum consolidated interest coverage ratio of 2.75 to 1.00. The failure to comply with any of these or other covenants would cause a default under the credit facilities. A default, if not waived, could result in acceleration of our debt, in which case the debt would become immediately due and payable. If this occurs, we may not be able to repay our debt or borrow sufficient funds to refinance it. Even if new financing were available, it may be on terms that are less attractive to us than our then existing credit facilities or it may not be on terms that are acceptable to us.

From time to time, our cash needs may exceed our internally generated cash flows, and our business could be materially and adversely affected if we were unable to obtain necessary funds from financing activities. From time to time, we may need to supplement our cash generation with proceeds from financing activities. Our revolving credit facility provides us with available financing to meet our ongoing cash needs.

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.

Historically, refining margins have been volatile, and they are likely to continue to be volatile in the future. 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.

A widely used benchmark in the fuel products industry to measure market values and margins is the Gulf Coast 3/2/1 crack spread, which represents the approximate gross margin resulting from refining crude oil, assuming that three barrels of a benchmark crude oil are converted, or cracked, into two barrels of gasoline and one barrel of heating oil. The Gulf Coast 3/2/1 crack spread, as reported by Bloomberg L.P., has averaged as follows:

Time Period	**Crack spread**
1990 to 1999	$ 3.04
2000 to 2004	$ 4.61
2005	$ 10.63
2006	$ 10.70
2007	$ 14.27
2008	$ 9.98
2009	$ 8.68
First quarter 2010	$ 8.89
Second quarter 2010	$ 12.20

Third quarter 2010	$ 8.60
Fourth quarter 2010	$ 9.89
Calendar year 2010	$ 9.90

Our actual refining margins vary from the Gulf Coast 3/2/1 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 3/2/1 crack spread as an indicator of the volatility and general levels of refining margins.

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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 along these price increases to our customers. Increases in selling prices for specialty products typically lag the rising cost of crude oil and may be difficult to implement 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 a 18.3% increase in the average sales price per barrel of our specialty products. It is possible we may not be able to pass on 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.

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 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.

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

The borrowing base under our revolving credit facility is determined weekly or monthly depending upon availability levels. 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 our amount of financial resources available to meet our capital requirements. Further, if at any time our available capacity under our revolving credit facility falls below $35.0 million, we may be required by our lenders to take steps to reduce our leverage, pay off our debts on an accelerated basis, limit or eliminate distributions to our unitholders or take other similar measures. In addition, decreases in the price of crude oil, may require us to post substantial amounts of cash collateral to our hedging counterparties in order to maintain our hedging positions. At December 31, 2010, we had $145.5 million in availability under our revolving credit facility. Please read 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. If the borrowing base under our revolving credit facility decreases or we are required to post substantial amounts of cash collateral to our hedging counterparties, it could have a material adverse effect on our liquidity, financial condition and our ability to distribute cash to our unitholders.

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 New York Mercantile Exchange (NYMEX) ranged between \$3.29 and \$6.01 per million British thermal unit, or MMBtu, in 2010 and between \$2.51 and \$6.07 per MMBtu in 2009. 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 21.6% and 20.7% of our total operating expenses included in cost of sales for the years ended

December 31, 2010 and 2009, respectively. If our natural gas costs rise, 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. We utilize derivative financial instruments related to the future price of crude oil, natural gas and fuel products with the intent of reducing volatility in our cash flows due to fluctuations in commodity prices and 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. For example, 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. 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. For example, during 2010 we entered into monthly crude oil collars and swaps to hedge up to approximately 11,000 bpd of crude oil purchases related to our specialty products segment, which had average total daily production for 2010 of approximately 32,000 bpd. As of December 31, 2010, we had significantly reduced the volume and duration of our crude oil collars and swap positions and were hedging approximately 1,200 bpd of crude oil purchases through March 31, 2011. Thus, we could be exposed to significant crude oil cost increases on a portion of our purchases. Please read 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 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.

We plan to grow our business in part through the reconfiguration and enhancement of our existing refinery assets. As a specific example, we completed an expansion project at our Shreveport refinery to increase throughput capacity and crude oil processing flexibility in May 2008. This expansion project 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.

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

We had approximately $378.2 million of outstanding indebtedness under our credit facilities as of December 31, 2010 and availability for borrowings of $145.5 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 $375.0 million under our senior secured revolving credit facility, subject to the borrowing base limitations in that credit agreement. For further discussion of our term loan and revolving credit facilities, please read Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Debt and Credit Facilities. 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 distributions to unitholders; 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, 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.

We may be unable to consummate potential acquisitions we identify or successfully integrate such acquisitions.

We regularly consider and enter into discussions regarding potential acquisitions that we believe are complementary to our business. Any such purchase is subject to substantial due diligence, the negotiation of a definitive purchase and sale agreement and ancillary agreements, including, but not limited to supply, transition services and licensing agreements, and the receipt of various board of directors, governmental and other approvals. In the alternative, if we are successful in closing any such acquisitions, we will be subject to many risks including integration risks and the risk that a substantial portion of an acquired business may not produce qualifying income for purposes of the Internal Revenue Code. If our non-qualifying income exceeds 10% we would lose our election to be treated as a partnership for tax purposes and will be taxed as a corporation.

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If our general financial condition deteriorates, we may be limited in our ability to issue letters of credit which may affect our ability to enter into hedging arrangements, to enter into leasing arrangements, or to purchase crude oil.

We rely on our ability to issue letters of credit to enter into hedging arrangements in an effort to reduce our exposure to adverse fluctuations in the prices of crude oil, natural gas and crack spreads. We also rely on our ability to issue letters of credit to purchase crude oil for our refineries, lease certain precious metals for use in our refinery operations and enter into cash flow hedges of crude oil and natural gas purchases and fuel products sales. If, due to our financial condition or other reasons, we are limited in our ability to issue letters of credit or we are unable to issue letters of credit at all, we may be required to post substantial amounts of cash collateral to our hedging counterparties, lessors or crude oil suppliers in order to continue these activities, which would adversely affect our liquidity and our ability to distribute cash to our unitholders.

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 refineries 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 in east Texas and north Louisiana. In 2010, subsidiaries of Plains and Genesis Crude Oil, L.P. supplied us with approximately 49.6% and 4.6%, respectively, of our total crude oil supplies under term contracts and evergreen crude oil supply contracts. In addition, 41.5% of our total crude oil purchases in 2010 were from Legacy Resources, an affiliate of our general partner, to supply crude oil to our Princeton and Shreveport refineries. Each of our refineries 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 terminable upon 90 days notice. Please read Items 1 and 2 Business and Properties 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 revenues, net income and cash available for distribution to unitholders 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. A material decrease in crude oil production from the fields that supply our refineries, as a result of depressed commodity prices, lack of drilling activity, natural production declines, governmental moratoriums on drilling or production activities or otherwise, could result in a decline in the volume of crude oil we refine. 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, which are affected by, among other things, prevailing and projected energy prices, demand for hydrocarbons, geological considerations, governmental regulation and the availability and cost of capital.

We are dependent on certain third-party pipelines for transportation of crude oil and refined products, and if these pipelines become unavailable to us, our revenues and cash available for distribution could decline.

Our Shreveport refinery is interconnected to pipelines that supply most of its crude oil and ship a portion of its refined fuel products to customers, such as pipelines operated by subsidiaries of Enterprise Products Partners L.P. and ExxonMobil. Since we do not own or operate any of these pipelines, their continuing operation is not within our control. If any of these third-party pipelines become unavailable to transport crude oil or our refined fuel products because of accidents, government regulation, terrorism or other events, our revenues, net income and cash available for distribution to unitholders could decline.

Distributions to unitholders 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 unitholders could be reduced.

Distributions to unitholders 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. 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 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.

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

Our crude oil and specialty hydrocarbon refining, terminal and related facility operations are subject to stringent and complex federal, regional, state and local environmental, health and safety 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 to limit or prevent releases of materials from our refineries, terminal, and related facilities, the expenditure of significant monies in the application of specific health and safety criteria addressing worker protection, and the incurrence of substantial costs and liabilities for pollution resulting from our operations or from those of prior owners. Numerous governmental authorities, such as the EPA, OSHA, and state agencies, such as the LDEQ, 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 laws, regulations, permits and orders may result in the assessment of administrative, civil, and criminal penalties, the imposition of remedial obligations, and the issuance of injunctions limiting or preventing some or all of our operations. On occasion, we receive notices of violation, enforcement proceedings and regulatory inquiries from governmental agencies alleging non-compliance with applicable environmental laws and other regulations. Please read Items 1 and 2 Business and Properties Environmental, Health and Safety Matters for additional information regarding our communications with the LDEQ and OSHA.

The workplaces associated with the facilities we operate are subject to the requirements of federal OSHA and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that we maintain information about hazardous materials used or produced in our operations and that we provide this information to employees, state and local government authorities, and local residents. Failure to comply with OSHA requirements, including general industry standards, recordkeeping requirements and monitoring of occupational exposure to regulated substances could reduce our ability to make distributions to our unitholders if we are subjected to penalties or significant compliance costs.

Our business subjects us to the inherent risk of incurring significant environmental liabilities in the operation of our refineries, terminal and related facilities.

There is inherent risk of incurring significant environmental costs and liabilities in the operation of our refineries, terminal, and related facilities due to our handling of petroleum hydrocarbons and wastes because of air emissions and water discharges related to our operations, and historical operations and waste disposal practices of prior owners of our facilities. We currently own or operate properties that for many years have been used for industrial activities, including refining or terminal storage operations, sometimes by third parties over whom we had no control with respect to their operations or waste disposal activities. Petroleum hydrocarbons or wastes have been released on or under the properties owned or operated by us. Joint and several strict liability may be incurred in connection with such releases of petroleum hydrocarbons and wastes on, under or from our properties and facilities. 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, 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.

Increasingly stringent environmental laws and regulations, unanticipated remediation obligations or emissions control expenditures and claims for penalties or damages could result in substantial costs and liabilities, and our ability to make distributions to our unitholders could suffer as a result. 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. As such, we can expect no economic assistance from any of them in the event that we are required to make expenditures to investigate or remediate any petroleum hydrocarbons, wastes or other materials.

Climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating costs and a decreased demand for our refining services.

In December 2009, the EPA published its findings that emissions of carbon dioxide, methane, and other greenhouse gases, or GHGs, present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth s atmosphere and other climate changes. These findings allow the EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. The EPA has adopted two sets of regulations under the Clean Air Act. The first limits emissions of GHGs from motor vehicles beginning with the 2012 model year. On June 3, 2010, the EPA published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration, or PSD, and Title V permitting programs. This rule tailors these permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. It is widely expected that facilities required to obtain PSD permits for their GHG emissions also will be required to reduce those emissions according to best available control technology standards for GHG that have yet to be developed. Also, in October 2009, the EPA published a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the United States, including refineries, on an annual basis, beginning in 2011 for emissions occurring after January 1, 2010. In addition, both houses of Congress have actively considered legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. These allowances would be expected to escalate significantly in cost over time. The adoption of any legislation or regulations that requires reporting of GHGs or otherwise limits emissions of GHGs from our equipment and operations could require us to incur increased operating costs and could adversely affect demand for the refined petroleum products we produce.

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 forward contracts, options and swap agreements. 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.

If we do not make acquisitions on economically acceptable terms, our future growth will be limited.

Our ability to grow depends 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 obtain financing for these acquisitions on economically acceptable terms, or (3) outbid by competitors, then our future growth and ability to increase distributions to our unitholders will 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 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 refineries, facilities and terminal operations face operating hazards, and the potential limits on insurance coverage could expose us to potentially significant liability costs.

Our operations are subject to certain operating hazards, and our cash from operations could decline if any of our facilities experiences a major accident, 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, on February 5, 2010, our Shreveport refinery experienced an explosion that caused us to shut down one of this refinery s environmental operating units until August 2010 when it was replaced with a newly constructed unit, resulting in modified operations during the

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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 90 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 environmental accidents. 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.

Downtime for maintenance at our refineries and facilities will reduce our revenues and cash available for distribution.

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 during the period of time that our processing units are not operating and could reduce our ability to make distributions to our unitholders.

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 and 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 could be reduced.

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

Borrowings under our revolving credit facility bear interest at a floating rate (3.75% as of December 31, 2010). Borrowings under our term loan facility bear interest at a floating rate (4.29% as of December 31, 2010). The interest rates are subject to adjustment based on fluctuations in the London Interbank Offered Rate (LIBOR) or prime rate. The interest rate under our term loan credit facility, entered into on January 3, 2008, is LIBOR plus 4.0%. 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.

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 northwest Louisiana. 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.

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. Except with respect to Mr. Grube, neither we, our general partner nor any affiliate thereof has entered into an employment agreement with any member of our senior management team or other key personnel. Furthermore, we do not maintain any key-man life insurance.

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

Substantially all of our operating personnel at our Princeton, Cotton Valley, Shreveport, Karns City and Dickinson facilities are employed under collective bargaining agreements that expire in October 2011, March 2013, April 2013, January 2012 and March 2013, respectively. Our inability 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.

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

The operating results for the fuel products segment and 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.

The recent adoption of financial reform legislation by the United States Congress could have an adverse effect on our ability to use derivative instruments to hedge risks associated with our business.

The United States Congress recently adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, including businesses like ours, that participate in that market. The new legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Act), was signed into law by the President on July 21, 2010, and requires the Commodities Futures Trading Commission (the CFTC) and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. In its rulemaking under the Act, the CFTC has proposed regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Although certain bona fide hedging transactions or positions would be exempt from these position limits, it is not possible at this time to predict what impact these regulations will have on our hedging program or when the CFTC will finalize these regulations. The Act may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivatives activities, although the application of those provisions to us is uncertain at this time. The Act may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and any new regulations could significantly increase the cost of derivatives contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivatives contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivatives contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation 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. Finally, the legislation 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 legislation 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.

Risks Inherent in an Investment in Us

The families of our chairman, chief executive officer and vice chairman, The Heritage Group and certain of their affiliates own a 54.6% 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.

The families of our chairman, chief executive officer and vice chairman, the Heritage Group, and certain of their affiliates own a 54.6% limited partner interest in us. In addition, The Heritage Group and the families of our chairman and chief executive officer and 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 applicable state 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 distributed to our unitholders;

- 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

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products in the continental United States for so long as it controls us. This restriction does not apply to certain assets and businesses which are more fully described under 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.

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:

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;

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.

In order to become a limited partner of our partnership, a common unitholder is required to agree 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, they have little ability to remove our general partner. 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.

Even if unitholders are dissatisfied, they cannot remove our general partner without its consent.

The unitholders are unable to remove the general partner without its consent because the general partner and its affiliates own sufficient units to be able to prevent its removal. The vote of the holders of at least 662/3% of all outstanding units voting together as a single class is required to remove the general partner. At February 18, 2011, the owners of our general partner and certain of their affiliates own 54.6% of our common units.

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.

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 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.

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

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. These expenses will include all costs incurred by our general partner and its affiliates in managing and operating us. Please read 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 18, 2011, our general partner and its affiliates own approximately 54.6% of the 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.

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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 price of our common units may continue to be volatile.

The market price of our common units 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 federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service, or IRS, treats us as a corporation for U.S. federal income tax purposes or we become subject to additional amounts of entity-level taxation for state tax purposes, it would substantially reduce the amount of cash available for distribution to common unitholders.

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. A publicly traded partnership such as us may be treated as a corporation for U.S. federal income tax purposes unless it satisfies a qualifying income exception. Based on our current operations we believe that we are treated as a partnership rather than a corporation for such purposes; however, a change in our business could cause us to be treated as a corporation for U.S. federal income tax purposes.

In addition, a change in current law may cause us to be treated as a corporation for U.S. federal income tax purposes. For example, members of Congress have recently considered substantive changes to the existing U.S. federal income tax laws that would affect the tax treatment of certain publicly traded partnerships. Any change to the U.S. federal income tax laws may or may not be applied retroactively. In addition, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity level taxation through the imposition of state income, franchise or other forms of taxation. If we were subject to federal income tax as a corporation or any state was to impose a tax upon us, our cash available to pay distributions would be reduced. Therefore, our treatment as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our 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 entity level taxation for federal, state or local income tax purposes, then the minimum quarterly distribution amount and the target distribution amounts will be adjusted to reflect the impact of that law on us.

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.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for U.S. federal income tax purposes. 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 the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, the costs of any contest with the IRS will be borne indirectly by our unitholders because the costs will reduce our cash available for distribution.

Unitholders may be required to pay taxes on income from us even if they do not receive any cash distributions from us.

Because our unitholders will be treated as partners in us for U.S. federal income tax purposes we will allocate a share of our taxable income to our unitholders which could be different in amount than the cash we distribute, and our unitholders may be required to pay any U.S. federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they do not receive any cash distributions from us.

Tax gain or loss on disposition of 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 they realized and their tax basis in those common units. Because distributions in excess of their allocable shares of our total net taxable income result in a reduction in their tax basis in their common units, the amount, if any, of such prior excess distributions with respect to the units sold will, in effect, become taxable income to our unitholders if they sell their units at a price greater than their tax basis in those common units, even if the price they receive is equal to 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 deductions. 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 our common units that may result in adverse tax consequences to them.

Investments in our common units by tax-exempt entities, including 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 exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes imposed at the highest applicable tax rate, and non-U.S. persons will be required to file U.S. federal tax returns and pay tax on their shares of our taxable income. Tax-exempt entities and non-U.S. persons should consult their tax advisors before investing in our common units.

We 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.

To maintain the uniformity of the economic and tax characteristics of our common units, we have adopted certain depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. These positions may result in an understatement of deductions and an overstatement of income to our unitholders. For example, we do not amortize certain goodwill assets, the value of which has been attributed to certain of our outstanding units. A subsequent holder of those units may be entitled to an amortization deduction attributable to that goodwill under Internal Revenue Code Section 743(b). But, because we cannot identify these units once they are traded by the initial holder, we do not allocate any subsequent holder of a unit any such amortization deduction. This approach may understate deductions available to those unitholders who own those units and may result in those unitholders reporting that they have a higher tax basis in their units than would be the case if the IRS strictly applied Treasury Regulations relating to these depreciation or amortization adjustments.

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This, in turn, may result in those unitholders reporting less gain or more loss on a sale of their units than would be the case if the IRS strictly applied those Treasury Regulations.

The IRS may challenge the manner in which we calculate our unitholder s basis adjustment under Section 743(b). If so, because the specific unitholders to which this issue relates cannot be identified, the IRS may assert adjustments to all unitholders selling units within the period under audit. A successful IRS challenge to this position or other positions we may take could adversely affect the amount of taxable income or loss allocated to our unitholders. It also could affect the gain from a unitholder s sale of common units or result in audit adjustments to our unitholders tax returns without the benefit of additional deductions. Consequently, a successful IRS challenge could have a negative impact on the value of our common units.

We have a subsidiary that is treated as a corporation for federal income tax purposes and subject to corporate-level income taxes.

We conduct all or a portion of our operations in which we market finished petroleum products to certain customers through a subsidiary that is organized as a corporation. We may elect to conduct additional operations through this corporate subsidiary in the future. This corporate subsidiary is obligated to pay corporate income taxes, which reduce the corporation s cash available for distribution to us and, in turn, to our unitholders. If the IRS were to successfully assert that this corporation has more tax liability than we anticipate or legislation were enacted that increased the corporate tax rate, our cash available for distribution to our unitholders would be further reduced.

We prorate our items of income, gain, loss and deduction between existing unitholders and unitholders who purchase 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 prorate our items of income, gain, loss and deduction between existing unitholders and unitholders who purchase our units 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 use of this proration method may not be permitted under existing Treasury Regulations. Recently, the U.S. Treasury Department issued proposed Treasury Regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly simplifying convention to allocate tax items. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to 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.

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

If a unitholder loans units to a short seller to cover a short sale of units, they may be considered as having disposed of the loaned units, and may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from such disposition. During the period of the loan, any of our income, gain, loss or deduction with respect to those units may not be reportable by a unitholder and any cash distributions received as to those units may be fully taxable as ordinary income. To assure unitholder status as a partner and avoid the risk of gain recognition from a loan to a short seller unitholders are urged to modify any applicable brokerage account agreements to prohibit brokers from borrowing their units.

We have adopted certain valuation methodologies for U.S. federal income tax purposes that may result in a shift of income, gain, loss and deduction between our general partner and the unitholders. The IRS may challenge this

treatment, which could adversely affect the value of the common units.

When we issue additional units or engage in certain other transactions, we will determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and our general partner, which may be unfavorable to such unitholders. Moreover, under our valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of taxable income, gain, loss and deduction between our general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of taxable 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.

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 constructively terminated as a partnership for federal income tax purposes if there is a sale or exchange within a twelve-month period of 50% or more of the total interests in our capital and profits. 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 could result in us filing two tax returns (and unitholders receiving two Schedule K-1s) for one calendar year. Our termination could also result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a calendar year, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for federal income tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred. The IRS has recently announced a relief procedure whereby if a publicly traded partnership that has constructively 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 tax years in which the termination occurs.

Unitholders may be subject to state, local and non-U.S. taxes and return filing requirements.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state and local taxes, non-U.S. taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property, even if unitholders do not live in any of those jurisdictions. Our unitholders will likely be required to file tax returns and pay taxes in some or all of these jurisdictions. Further, unitholders may be subject to penalties for failure to comply with those requirements. We do business in 30 states. The states we operate in, with the exception of Texas and Florida, currently impose a personal income tax as well as an income tax on corporations and other entities. As we make acquisitions or expand our business, we may own assets or do business in additional states that impose a personal income tax. It is the responsibility of our common unitholders to file all required U.S. federal, state, local and non-U.S. tax returns.

The risks described in this Annual Report are not the only risks facing the Company. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition or future results.

Item 1B. *Unresolved Staff Comments*

None.

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, 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 I, Item 8 Financial Statements and Supplementary Data Notes to Calumet Specialty Products Partners, L.P. Consolidated Financial Statements is incorporated herein by reference.

Item 4. ***(Removed and Reserved)***

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 under the symbol CLMT. Our common units began trading on January 26, 2006 at an initial public offering price of $21.50. Prior to that date, there was no public market for our common units. 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. During each quarter in the years ended December 31, 2010 and 2009, identical cash distributions per unit were paid among all outstanding common and subordinated units.

	Low	High	Cash Distribution per Unit (1)
Year ended December 31, 2009:			
First quarter	$ 8.11	$ 13.50	$ 0.45
Second quarter	$ 9.45	$ 16.84	$ 0.45
Third quarter	$ 13.20	$ 18.53	$ 0.45
Fourth quarter	$ 14.75	$ 19.87	$ 0.455
Year ended December 31, 2010:			
First quarter	$ 17.75	$ 21.31	$ 0.455
Second quarter	$ 14.00	$ 23.93	$ 0.455
Third quarter	$ 16.20	$ 19.89	$ 0.46
Fourth quarter	$ 19.39	$ 22.23	$ 0.47

(1) We also paid cash distributions to our general partner with respect to its 2% general partner interest.

As of February 18, 2011, there were approximately 23 unitholders of record of our common units. This number does not include unitholders whose units are held in trust by other entities. The actual number of unitholders is greater than the number of holders of record. As of February 18, 2011, there were 35,279,778 common units outstanding. The number of common units outstanding on this date includes 13,066,000 common units that converted from subordinated units on February 16, 2011. The last reported sale price of our common units by NASDAQ on February 18, 2011 was $23.83.

On December 14, 2009, we completed a public equity offering in which we sold 3,000,000 common units to the underwriters at a price to the public of $18.00 per common unit and received net proceeds of approximately $51.2 million. In addition, on January 7, 2010 we sold an additional 47,778 common units to the underwriters at a price to the public of $18.00 per common unit pursuant to the underwriters over-allotment option. In connection with this offering, our general partner contributed an additional $1.1 million to us to retain its 2% general partner interest.

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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; or
- 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.

Intent to Distribute the Minimum Quarterly Distribution. 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 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 is existing, under our credit agreements. Please read 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 credit agreements that restrict our ability to make distributions. On February 14, 2011, we paid a quarterly cash distribution of $0.47 per unit on all outstanding units totaling $16.9 million for the quarter ended December 31, 2010 to all unitholders of record as of the close of business on February 4, 2011.

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 719,995 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 below) 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 did not earn incentive distribution rights during the years ended December 31, 2009 and December 31, 2010.

Conversion of Subordinated Units. In February 2011, we satisfied the last of the earnings and distribution tests contained in our partnership agreement for the automatic conversion of all 13,066,000 outstanding subordinated units into common units on a one-for-one basis. The last of these requirements was met upon payment of the quarterly distribution paid on February 14, 2011. Two days following this quarterly distribution to unitholders, or February 16, 2011, all of the outstanding subordinated units automatically converted to common units.

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After the subordination period ended on February 16, 2011, 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 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%

Equity Compensation Plans

The equity compensation plan information required by Item 201(d) of Regulation S-K in response to this item is incorporated by reference into 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.

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Item 6. ***Selected Financial Data***

The following table shows selected historical consolidated financial and operating data of Calumet Specialty Products Partners, L.P. and its consolidated subsidiaries (the Company) and includes Calumet Lubricants Co., Limited Partnership (Predecessor) for the period of January 1, 2006 through January 31, 2006. The selected historical financial data as of and after December 31, 2008 includes the operations acquired as part of the acquisition of Penreco from their date of acquisition, January 3, 2008.

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 and net cash provided by operating activities, our most directly comparable financial performance and liquidity measures calculated in accordance with 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 of this Annual Report except for operating data such as sales volume, feedstock runs and production. The table also should be read together with Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations.

	Year Ended December 31,				
	2010	**2009**	**2008**	**2007**	**2006**
	(In thousands, except unit, per unit and operations data)				
Summary of Operations Data:					
Sales	$ 2,190,752	$ 1,846,600	$ 2,488,994	$ 1,637,848	$ 1,641,048
Cost of sales	1,992,003	1,673,498	2,235,111	1,456,492	1,436,108
Gross profit	198,749	173,102	253,883	181,356	204,940
Operating costs and expenses:					
Selling, general and administrative	35,224	32,570	34,267	19,614	20,430
Transportation	85,471	67,967	84,702	54,026	56,922
Taxes other than income taxes	4,601	3,839	4,598	3,662	3,592
Other	1,963	1,366	1,576	2,854	863
Operating income	71,490	67,360	128,740	101,200	123,133
Other income (expense):					
Interest expense	(30,497)	(33,573)	(33,938)	(4,717)	(9,030)
Interest income	70	170	388	1,944	2,951
Debt extinguishment costs			(898)	(352)	(2,967)
Realized gain (loss) on derivative instruments	(7,704)	8,342	(58,833)	(12,484)	(30,309)
Unrealized gain (loss) on derivative instruments	(15,843)	23,736	3,454	(1,297)	12,264
Gain on sale of mineral rights			5,770		

Other	(217)	(4,099)	11	(919)	(274)
Total other expense	(54,191)	(5,424)	(84,046)	(17,825)	(27,365)
Income before income taxes	17,299	61,936	44,694	83,375	95,768
Income tax expense	598	151	257	501	190
Net income	$ 16,701	$ 61,785	$ 44,437	$ 82,874	$ 95,578
Weighted average limited partner units outstanding:					
Basic	35,334,720	32,372,000	32,232,000	29,744,000	27,708,000
Diluted	35,351,020	32,372,000	32,232,000	29,746,000	27,708,000
Common and subordinated unitholders basic and diluted net income per unit	$ 0.46	$ 1.87	$ 1.35	$ 2.61	$ 3.19
Cash distributions declared per common and subordinated unit	$ 1.84	$ 1.81	$ 1.98	$ 2.43	$ 1.30

	Year Ended December 31,				
	2010	2009	2008	2007	2006
	(In thousands, except unit, per unit and operations data)				
Balance Sheet Data (at period end):					
Property, plant and equipment, net	$ 612,433	$ 629,275	$ 659,684	$ 442,882	$ 191,732
Total assets	1,016,672	1,031,856	1,081,062	678,857	531,651
Accounts payable	174,715	109,976	93,855	167,977	78,752
Long-term debt	369,275	401,058	465,091	39,891	49,500
Total partners capital	398,279	485,347	473,212	399,644	385,267
Cash Flow Data:					
Net cash flow provided by (used in):					
Operating activities	$ 134,143	$ 100,854	$ 130,341	$ 167,546	$ 166,768
Investing activities	(34,759)	(22,714)	(480,461)	(260,875)	(75,803)
Financing activities	(99,396)	(78,139)	350,133	12,409	(22,183)
Other Financial Data:					
EBITDA	$ 109,044	$ 157,612	$ 135,575	$ 102,719	$ 119,586
Adjusted EBITDA	130,369	146,017	128,075	104,272	104,458
Distributable Cash Flow	79,040	101,736	94,514	87,684	85,913
Operating Data (bpd):					
Total sales volume (1)	55,668	57,086	56,232	47,663	50,345
Total feedstock runs (2)	55,957	60,081	56,243	48,354	51,598
Total facility production (3)	57,314	58,792	55,330	47,736	50,213

(1) Total sales volume includes sales from the production of our facilities and certain third-party facilities pursuant to supply and/or processing agreements, and sales of inventories.

(2) Total feedstock runs represents the barrels per day of crude oil and other feedstocks processed at our facilities and 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 certain third-party facilities pursuant to supply and/or processing agreements, including the LyondellBasell Agreements. The difference between total facility production and total feedstock runs is primarily a result of the time lag between the input of feedstocks and production of finished products and volume loss.

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 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 our 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

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

We define EBITDA as net income plus interest expense (including debt issuance and extinguishment costs), taxes and depreciation and amortization. We define Adjusted EBITDA to be Consolidated EBITDA as defined in our credit facilities. Consistent with that definition, Adjusted EBITDA means, for any period: (1) net income plus (2)(a) interest expense; (b) taxes; (c) depreciation and amortization; (d) unrealized losses from mark to market accounting for hedging activities; (e) unrealized items decreasing net income (including the non-cash impact of restructuring, decommissioning and asset impairments in the periods presented); and (f) other non-recurring expenses reducing net income which do not represent a cash item for such period; minus (3)(a) tax credits; (b) unrealized items increasing net income (including the non-cash impact of restructuring, decommissioning and asset impairments in the periods presented); (c) unrealized gains from mark to market accounting for hedging activities; and (d) other non-recurring expenses and unrealized items that reduced net income for a prior period, but represent a cash item in the current period.

We are required to report Adjusted EBITDA to our lenders under our credit facilities and it is used to determine our compliance with the consolidated leverage and consolidated interest coverage tests thereunder. Please refer to 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 our credit agreements.

We define Distributable Cash Flow as Adjusted EBITDA less replacement capital expenditures, cash interest paid (excluding capitalized interest) and income tax expense. Distributable Cash Flow is used by us and our investors to analyze our ability to pay distributions.

EBITDA, Adjusted EBITDA and Distributable Cash Flow should not be considered alternatives to net income, operating income, net cash provided by operating activities or any other measure of financial performance presented in accordance with GAAP. In evaluating our performance as measured by EBITDA, Adjusted EBITDA and Distributable Cash Flow, management recognizes and considers the limitations of these measurements. EBITDA, Adjusted EBITDA and Distributable Cash Flow do not reflect our obligations for the payment of income taxes, interest expense or other obligations such as capital expenditures. Accordingly, EBITDA, Adjusted EBITDA and Distributable Cash Flow are only three of the measurements that management utilizes. Moreover, our EBITDA, Adjusted EBITDA and Distributable Cash Flow may not be comparable to similarly titled measures of another company because all companies may not calculate EBITDA, Adjusted EBITDA and Distributable Cash Flow in the same manner. The following table presents a reconciliation of both net income to EBITDA, Adjusted EBITDA and Distributable Cash Flow and Distributable Cash Flow, Adjusted EBITDA and EBITDA to net cash provided by operating activities, our most directly comparable GAAP financial performance and liquidity measures, for each of the periods indicated.

	Year Ended December 31,				
	2010	2009	2008	2007	2006
	(In thousands)				
Reconciliation of net income to EBITDA, Adjusted EBITDA and Distributable Cash Flow:					
Net income	$ 16,701	$ 61,785	$ 44,437	$ 82,874	$ 95,578
Add:					
Interest expense and debt extinguishment costs	30,497	33,573	34,836	5,069	11,997
Depreciation and amortization	61,248	62,103	56,045	14,275	11,821
Income tax expense	598	151	257	501	190
EBITDA	$ 109,044	$ 157,612	$ 135,575	$ 102,719	$ 119,586
Add:					
Unrealized loss (gain) from mark to market accounting for hedging activities	$ 18,833	$ (14,458)	$ (11,509)	$ 3,487	$ (13,145)
Prepaid non-recurring expenses and accrued non-recurring expenses, net of cash outlays	2,492	2,863	4,009	(1,934)	(1,983)
Adjusted EBITDA	$ 130,369	$ 146,017	$ 128,075	$ 104,272	$ 104,458
Less:					
Adjusted EBITDA attributable to Predecessor					(4,494)
Replacement capital expenditures (1)	(24,342)	(13,787)	(6,304)	(12,007)	(5,737)
Cash interest expense (2)	(26,389)	(30,343)	(27,000)	(4,080)	(8,124)
Income tax expense	(598)	(151)	(257)	(501)	(190)
Distributable Cash Flow	$ 79,040	$ 101,736	$ 94,514	$ 87,684	$ 85,913

(1) Replacement capital expenditures are defined as those capital expenditures which do not increase operating capacity or reduce operating costs.

(2) Represents cash interest paid by the Company, excluding capitalized interest.

	Year Ended December 31, 2010	2009	2008 (In thousands)	2007	2006
Reconciliation of Distributable Cash Flow, Adjusted EBITDA and EBITDA to net cash provided by operating activities:					
Distributable Cash Flow	$ 79,040	$ 101,736	$ 94,514	$ 87,684	$ 85,913
Add:					
Adjusted EBITDA attributable to Predecessor					4,494
Replacement capital expenditures (1)	24,342	13,787	6,304	12,007	5,737
Cash interest expense (2)	26,389	30,343	27,000	4,080	8,124
Income tax expense	598	151	257	501	190
Adjusted EBITDA	$ 130,369	$ 146,017	$ 128,075	$ 104,272	$ 104,458
Less:					
Unrealized (gain) loss from mark to market accounting for hedging activities	$ 18,833	$ (14,458)	$ (11,509)	$ 3,487	$ (13,145)
Prepaid non-recurring expenses and accrued non-recurring expenses, net of cash outlays	2,492	2,863	4,009	(1,934)	(1,983)
EBITDA	$ 109,044	$ 157,612	$ 135,575	$ 102,719	$ 119,586
Add:					
Interest expense and debt extinguishment costs, net of amortization	(26,633)	(29,902)	(31,440)	(4,638)	(11,997)
Unrealized (gain) loss on derivative instruments	15,843	(23,736)	(3,454)	1,297	(12,264)
Income taxes	(598)	(151)	(257)	(501)	(190)
Provision for doubtful accounts	74	(916)	1,448	41	172
Non-cash debt extinguishment costs			898	352	2,967
Changes in assets and liabilities:					
Accounts receivable	(35,267)	(12,296)	45,042	(15,038)	16,031
Inventory	(9,860)	(18,726)	55,532	3,321	(2,554)
Other current assets	4,669	(2,848)	1,834	(4,121)	16,183
Derivative activity	2,990	8,531	41,757	2,121	(879)
Accounts payable	64,739	15,951	(103,136)	89,225	33,993
Other liabilities	11,853	(905)	(1,284)	(4,150)	657
Other, including changes in noncurrent assets and liabilities	(2,711)	8,240	(12,174)	(3,082)	5,063
Net cash provided by operating activities	$ 134,143	$ 100,854	$ 130,341	$ 167,546	$ 166,768

(1) Replacement capital expenditures are defined as those capital expenditures which do not increase operating capacity or reduce operating costs.

(2) Represents cash interest paid by the Company, excluding capitalized interest.

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, 2010, 2009, and 2008. 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 own plants located in Princeton, Louisiana, Cotton Valley, Louisiana, Shreveport, Louisiana, Karns City, Pennsylvania, and Dickinson, Texas, and a terminal located in Burnham, Illinois. Our business is organized into two segments: specialty products and fuel products. In our specialty products segment, we process crude oil and other feedstocks into a wide variety of customized lubricating oils, white mineral oils, solvents, petrolatums and waxes. Our specialty products are sold to domestic and international customers who purchase them primarily as raw material components for basic industrial, consumer and automotive goods. In our fuel products segment, we process crude oil into a variety of fuel and fuel-related products, including gasoline, diesel and jet fuel. In connection with our production of specialty products and fuel products, we also produce asphalt and a limited number of other by-products which are allocated to either the specialty products or fuel products segment. In 2010, approximately 94.3% of our gross profit was generated from our specialty products segment and approximately 5.7% of our gross profit was generated from our fuel products segment.

2010 Update

For the years ended December 31, 2010 and 2009, 53.0% and 45.0%, respectively, of our sales volume and 94.3% and 81.8%, respectively, of our gross profit was generated from our specialty products segment while, for the same periods, 47.0% and 55.0%, respectively, of our sales volume and approximately 5.7% and 18.2%, respectively, of our gross profit was generated from our fuel products segment.

Despite uncertainty surrounding the pace of recovery in the overall economy, we noted continued improvements in demand for our specialty products, with particular strength in the second half of the year. Specialty products segment sales volume during the last six months of 2010 combined were 21.7% higher than the same six-month period in 2009, with an increase of 14.9% for the full year of 2010 compared to 2009. Specialty segment gross profit also improved in 2010 compared to 2009 supported by relatively stable crude oil prices and increased demand for our specialty products. Our specialty products segment generated a gross profit margin of 15.2% for the last six months of 2010 compared to a gross profit margin of 11.5% for the same period in 2009.

While our total production in 2010 was relatively flat compared to 2009, our production levels trended higher over the course of the year. During the first quarter of 2010 we opted to run at reduced crude oil rates, primarily at our Shreveport refinery, due to the poor economics of running additional barrels in both the specialty products and fuel products segments. We also experienced the failure of an environmental operating unit during the first quarter of 2010 and completed scheduled turnarounds at our Shreveport refinery during the second and fourth quarters of 2010 which impacted overall production levels for the year. Subsequent to the completion of the extended turnaround at the Shreveport refinery in April 2010, we increased this refinery s throughput rates in order to meet increasing specialty products demand and historically higher demand for fuel products during the second and third quarters or 2010. Other factors increasing production levels year over year were higher production volumes at our Cotton Valley and Princeton refineries as well as increased specialty products volumes under the LyondellBasell Agreements, which were effective in November 2009. We intend to continue to run at these higher production levels in 2011 based on current demand for both specialty products and fuel products.

We improved our cash flow from operations by generating $134.1 million during 2010 with $91.6 million generated in the last six months of 2010. We paid distributions of $65.7 million to our unitholders during 2010, an increase of $6.5 million compared to 2009. We continue to focus our efforts on generating positive cash flow from operations which we expect will be used to i) maintain compliance with the financial covenants of our credit agreements, ii) improve our liquidity position, iii) pay our quarterly distributions to our unitholders and iv) provide funding for general operational purposes.

LyondellBasell Agreements

Effective November 4, 2009, we entered into the LyondellBasell Agreements with Houston Refining to form a long-term specialty products affiliation. The initial term of the LyondellBasell Agreements expires on October 31, 2014 after which it is automatically extended for additional one-year terms until either party terminates with 24 months notice. Under the terms of the LyondellBasell Agreements, (i) we are required to purchase at least a minimum volume of 3,100 bpd of naphthenic lubricating oils produced at Houston Refining s Houston, Texas refinery, and we have a right of first refusal to purchase any additional naphthenic lubricating oils produced at the refinery, and (ii) Houston Refining is required to process a minimum of approximately 800 bpd of white mineral oil for us at its Houston, Texas refinery, which supplements the white mineral oil production at our Karns City and Dickinson facilities. Our annual purchase commitment under these agreements is approximately $158.0 million. LyondellBasell has also granted us rights to use certain registered trademarks and tradenames, including Tufflo, Duoprime, Duotreat, Crystex, Ideal and Aquamarine.

While no fixed assets were purchased under the LyondellBasell Agreements, these agreements have increased our working capital as of December 31, 2010 by approximately $24.6 million from December 31, 2009 and our sales by $139.6 million for the year ended December 31, 2010 as compared to the prior year.

Key Performance Measures

Our sales and net income are principally affected by the price of crude oil, demand for specialty and fuel products, prevailing crack spreads for fuel products, the price of natural gas used as fuel in our operations and our results from derivative instrument activities.

Our primary raw materials are crude oil and other specialty feedstocks and our primary outputs are specialty petroleum and fuel products. The prices of crude oil, specialty products and fuel products are subject to fluctuations in response to changes in supply, demand, market uncertainties and a variety of additional factors beyond our control. We monitor these risks and enter into financial derivatives designed to mitigate the impact of commodity price fluctuations on our business. The primary purpose of our commodity risk management activities is to economically hedge our cash flow exposure to commodity price risk so that we can meet our cash distribution, debt service and capital expenditure requirements despite fluctuations in crude oil and fuel products prices. We enter into derivative contracts for future periods in quantities that do not exceed our projected purchases of crude oil and natural gas and sales of fuel products. Please read Item 7A Quantitative and Qualitative Disclosures About Market Risk Commodity Price Risk. As of December 31, 2010, we have hedged approximately 11.4 million barrels of fuel products through December 2012 at an average refining margin of $12.62 per barrel with average refining margins ranging from a low of $11.87 in 2011 to a high of $13.07 in 2012. As of December 31, 2010, we have approximately 71,000 barrels of crude oil swaps through March 2011 to hedge our purchases of crude oil for specialty products production. The strike prices and types of these crude oil swaps vary. Please refer to Item 7A Quantitative and Qualitative Disclosures About Market Risk Existing Commodity Derivative Instruments and Existing Interest Rate Derivative Instruments for detailed information regarding our derivative instruments and our commodity price and interest rate risks.

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

- sales volumes;

production yields; and

specialty products and fuel products gross profit.

Sales volumes. We view the volumes of specialty products and fuel products sold as an important measure of our ability to effectively utilize our refining assets. Our ability to meet the demands of our customers is driven by the volumes of crude oil and feedstocks that we run at our facilities. Higher volumes improve profitability both through the spreading of fixed costs over greater volumes and the 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, which we refer to as production yield.

Specialty products and fuel products gross profit. Specialty products and fuel products gross profit are important measures of our ability to maximize the profitability of our specialty products and fuel products segments. We define specialty products and fuel products gross profit as sales less the cost of crude oil and other feedstocks and other production-related expenses, the most significant portion of which includes labor, plant fuel, utilities, contract services, maintenance, depreciation and processing materials. We use specialty products and fuel products gross profit as indicators of our ability to manage our business during periods of crude oil and natural gas price fluctuations, as the prices of our specialty products and fuel products generally do not change immediately with changes in the price of crude oil and natural gas. The increase in selling prices typically lags behind the rising costs of crude oil feedstocks for specialty products. Other than plant fuel, production-related expenses generally remain stable across broad ranges of throughput volumes, but can fluctuate depending on maintenance activities performed during a specific period.

Our fuel products segment gross profit may differ from a standard U.S. Gulf Coast 2/1/1 or 3/2/1 market crack spread due to many factors, including our fuel products mix as shown in our production table being different than the ratios used to calculate such market crack spreads, the allocation of by-product (primarily asphalt) losses at the Shreveport refinery to the fuel products segment, operating costs including fixed costs, derivative activity to hedge our fuel products segment revenues and cost of crude oil reflected in gross profit and our local market pricing differential in Shreveport, Louisiana as compared to U.S. Gulf Coast postings.

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

Results of Operations

The following table sets forth information about our combined operations. Production volume differs from sales volume due to changes in inventory. The table does not include volumes under the LyondellBasell Agreements in 2008 and the majority of 2009, as such agreements were not effective until November 4, 2009.

	Year Ended December 31,		
	2010	**2009**	**2008**
		(In bpd)	
Total sales volume (1)	55,668	57,086	56,232
Total feedstock runs (2)	55,957	60,081	56,243
Facility production: (3)			
Specialty products:			
Lubricating oils	13,697	11,681	12,462
Solvents	9,347	7,749	8,130
Waxes	1,220	1,049	1,736
Fuels	1,050	853	1,208
Asphalt and other by-products	6,907	7,574	6,623
Total	32,221	28,906	30,159

Fuel products:			
Gasoline	8,754	9,892	8,476
Diesel	10,800	12,796	10,407
Jet fuel	5,004	6,709	5,918
By-products	535	489	370
Total	25,093	29,886	25,171
Total facility production (3)	57,314	58,792	55,330

(1) Total sales volume includes sales from the production at our facilities and, certain third-party facilities pursuant to supply and/or processing agreements, and sales of inventories.

(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 decrease in feedstock runs in 2010 compared to 2009 is due primarily to our decision to reduce crude oil run rates at our Shreveport refinery during the entire first quarter of 2010 because of the poor economics of running additional barrels, the failure of an environmental operating unit during the first quarter of 2010 and scheduled turnarounds completed in the second and fourth quarters related to various operating units at our Shreveport refinery. These decreases were partially offset by higher year-long throughput rates at our Cotton Valley refinery and the addition of volumes under the LyondellBasell Agreements.

The increase in feedstock runs in 2009 compared to 2008 is due primarily to the Shreveport refinery expansion project placed in service in May 2008, resulting in a full year of increased production in 2009 compared to 2008, and the addition of volumes under the LyondellBasell Agreements in 2009. Partially offsetting these increases were lower overall feedstock runs at our other facilities in 2009 compared to 2008 due to general economic conditions.

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

The increase in the production of specialty products in 2010 compared to 2009 is primarily the result of the addition of volumes under the LyondellBasell Agreements and higher throughput rates at our Cotton Valley refinery. The reduction in production of fuel products in 2010 compared to 2009 is due primarily to reduced feedstock runs at our Shreveport refinery as discussed in footnote 2 of this table.

The change in production mix to higher fuel products production in 2009 compared to 2008 is due primarily to reduced demand for certain specialty products due to overall economic conditions.

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

	Year Ended December 31,		
	2010	**2009**	**2008**
		(In thousands)	
Sales	$ 2,190,752	$ 1,846,600	$ 2,488,994
Cost of sales	1,992,003	1,673,498	2,235,111
Gross profit	198,749	173,102	253,883
Operating costs and expenses:			
Selling, general and administrative	35,224	32,570	34,267
Transportation	85,471	67,967	84,702
Taxes other than income taxes	4,601	3,839	4,598
Other	1,963	1,366	1,576
Operating income	71,490	67,360	128,740
Other income (expense):			
Interest expense	(30,497)	(33,573)	(33,938)
Debt extinguishment costs			(898)
Realized gain (loss) on derivative instruments	(7,704)	8,342	(58,833)
Unrealized gain (loss) on derivative instruments	(15,843)	23,736	3,454
Gain on sale of mineral rights			5,770
Other	(147)	(3,929)	399
Total other expense	(54,191)	(5,424)	(84,046)
Income before income taxes	17,299	61,936	44,694
Income tax expense	598	151	257
Net income	$ 16,701	$ 61,785	$ 44,437
EBITDA	$ 109,044	$ 157,612	$ 135,575
Adjusted EBITDA	$ 130,369	$ 146,017	$ 128,075
Distributable Cash Flow	$ 79,040	$ 101,736	$ 94,514

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

Sales. Sales increased $344.2 million, or 18.6%, to $2,190.8 million in 2010 from $1,846.6 million in 2009. Sales for each of our principal product categories in these periods were as follows:

	Year Ended December 31,		
	2010	2009	% Change
	(Dollars in thousands)		
Sales by segment:			
Specialty products:			
Lubricating oils	$ 759,701	$ 500,938	51.7%
Solvents	396,894	260,185	52.5%
Waxes	124,964	97,658	28.0%
Fuels (1)	5,507	8,951	(38.5)%
Asphalt and by-products (2)	121,806	103,488	17.7%
Total specialty products	$ 1,408,872	$ 971,220	45.1%
Total specialty products sales volume (in barrels)	10,766,000	9,370,000	14.9%
Average specialty products sales price per barrel	$ 130.86	$ 103.65	26.3%
Fuel products:			
Gasoline	$ 304,544	$ 317,435	(4.1)%
Diesel	330,756	372,359	(11.2)%
Jet fuel	135,796	167,638	(19.0)%
By-products (3)	10,784	17,948	(39.9)%
Total fuel products	$ 781,880	$ 875,380	(10.7)%
Total fuel products sales volume (in barrels)	9,553,000	11,466,000	(16.7)%
Average fuel products sales price per barrel	$ 88.93	$ 69.84	27.3%
Total sales	$ 2,190,752	$ 1,846,600	18.6%
Total sales volume (in barrels)	20,319,000	20,836,000	(2.5)%

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

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

(3) Represents by-products produced in connection with the production of fuels at the Shreveport refinery.

Specialty products segment sales in 2010 increased $437.7 million, or 45.1%, due primarily to an increase in the average selling price per barrel of $27.21, or 26.3%, and a 14.9% increase in sales volume, from approximately 9.4 million barrels in 2009 to 10.8 million barrels in 2010. Specialty products average selling prices per barrel increased in all product categories driven by improving overall demand and in response to an increase of 31.8% in the average cost of crude oil per barrel in 2010 compared to 2009. The increased sales volume is due primarily to improving overall specialty products demand as a result of improved economic conditions and the addition of sales volume under the LyondellBasell Agreements in 2010, partially offset by decreased production due primarily to our decision to reduce crude oil run rates at our Shreveport refinery during the entire first quarter of 2010 because of the poor economics of running additional barrels, the failure of an environmental operating unit during the first quarter of 2010 and scheduled turnarounds completed in the second quarter related to various operating units at our Shreveport refinery.

Fuel products segment sales in 2010 decreased $93.5 million, or 10.7%, due primarily to a 16.7% decrease in sales volumes, from approximately 11.5 million barrels in 2009 to 9.6 million barrels in 2010, due primarily to our decision to reduce crude oil run rates at our facilities during the entire first quarter of 2010 because of the poor

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economics of running additional barrels, the failure of an environmental operating unit during the first quarter of 2010 and scheduled turnarounds completed in the second and fourth quarters related to various operating units at our Shreveport refinery. Partially offsetting this decrease in sales volume was an increase in the average selling price per barrel of $19.09, or 27.3%, as compared to a 32.3% increase in the average cost of crude oil per barrel. Increases in sales prices lagged crude oil cost increases due to local market conditions. Also contributing to the overall decrease in sales was a $142.2 million decrease in derivative gains on our fuel products cash flow hedges recorded in sales. Please read Gross Profit below for the net impact of our crude oil and fuel products derivative instruments designated as hedges.

Gross Profit. Gross profit increased $25.6 million, or 14.8%, to $198.7 million in 2010 from $173.1 million in 2009. Gross profit for our specialty and fuel products segments was as follows:

	Year Ended December 31,		
	2010	2009	% Change
	(Dollars in thousands)		
Gross profit by segment:			
Specialty products	$ 187,416	$ 141,577	32.4%
Percentage of sales	13.3%	14.6%	
Specialty products gross profit per barrel	$ 17.41	$ 15.11	15.2%
Fuel products	$ 11,333	$ 31,525	(64.1)%
Percentage of sales	1.4%	3.6%	
Fuel products gross profit per barrel	$ 1.19	$ 2.75	(56.7)%
Total gross profit	$ 198,749	$ 173,102	14.8%
Percentage of sales	9.1%	9.4%	

The increase in specialty products segment gross profit is due primarily to the 14.9% increase in sales volume. Also improving our gross profit was an increase of $10.9 million in 2010 compared to 2009 from the liquidation of lower cost inventory layers. Further, the increase in the average selling price per barrel of $27.21 exceeded the increase in the average cost of crude oil per barrel. Partially offsetting these increases were higher operating costs per barrel sold at our Shreveport refinery due to lower production levels in 2010 compared to 2009.

The decrease in fuel products segment gross profit is due primarily to reduced sales volume of 16.7%, increased crude oil costs per barrel of 32.3% compared to the 27.3% increase in the average sales price per barrel, a $15.6 million reduction in gains from the liquidation of lower cost inventory layers, higher operating costs per barrel at our Shreveport refinery due to lower production levels and decreased derivative gains of $4.6 million from our crack spread cash flow hedges.

Selling, general and administrative. Selling, general and administrative expenses increased $2.7 million, or 8.1%, to $35.2 million in 2010 from $32.6 million in 2009. This increase is due primarily to lower bad debt expense in 2009 resulting from the recovery of $0.9 million account receivable and the write off of the remaining costs related to the proposed offering for sale of senior unsecured notes in July 2010 which we opted not to complete.

Transportation. Transportation expenses increased $17.5 million, or 25.8%, to $85.5 million in 2010 from $68.0 million in 2009. This increase is due primarily to increased sales volumes of lubricating oils, solvents and waxes.

Interest expense. Interest expense decreased $3.1 million, or 9.2%, to $30.5 million in 2010 from $33.6 million in 2009. This decrease is due primarily to lower interest rates and lower balances being carried on the Company s revolver and term loan during the 2010 as compared to 2009. Revolver borrowings were reduced due to reductions in working capital as we improved payment terms with certain suppliers.

Realized gain (loss) on derivative instruments. Realized gain (loss) on derivative instruments decreased $16.0 million to a loss of $7.7 million in 2010 from an $8.3 million gain in 2009. This decrease is due primarily to reduced derivative gains of $13.6 million in 2010 on settlements of our crack spread derivatives used to economically lock in gains on a portion of our fuel products segment derivative hedging activity. Also contributing to this decrease was higher loss ineffectiveness on settled fuel products derivatives designated as cash flow hedges of $9.2 million. Partially offsetting these items were decreased realized losses in 2010 on crude oil derivatives in our specialty products segment due to the significant decline in crude oil prices late in 2008 (which resulted in larger realized losses early in 2009), whereas crude oil prices were relatively stable in 2010 as well as significantly less volume of these derivative contracts settled in 2010.

Unrealized gain (loss) on derivative instruments. Unrealized gain (loss) on derivative instruments decreased $39.6 million, to a $15.8 million loss in 2010 from a $23.7 million gain in 2009. This increased loss is due primarily to decreased gains of $11.4 million on the derivatives used to economically hedge our specialty products crude oil purchases and increased losses of $7.8 million on our crack spread derivatives used to economically lock in gains on a portion of our fuel products segment derivative hedging activity with minimal related activity in 2010. This decrease was also due to lower gain ineffectiveness in 2010 as compared to 2009.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

Sales. Sales decreased $642.4 million, or 25.8%, to $1,846.6 million in 2009 from $2,489.0 million in 2008. Sales for each of our principal product categories in these periods were as follows:

	Year Ended December 31,		
	2009	2008	% Change
	(Dollars in thousands)		
Sales by segment:			
Specialty products:			
Lubricating oils	$ 500,938	$ 841,225	(40.5)%
Solvents	260,185	419,831	(38.0)%
Waxes	97,658	142,525	(31.5)%
Fuels (1)	8,951	30,389	(70.5)%
Asphalt and by-products (2)	103,488	144,065	(28.2)%
Total specialty products	$ 971,220	$ 1,578,035	(38.5)%
Total specialty products sales volume (in barrels)	9,370,000	10,289,000	(8.9)%
Average specialty products sales price per barrel	$ 103.65	$ 153.37	(32.4)%
Fuel products:			
Gasoline	$ 317,435	$ 332,669	(4.6)%
Diesel	372,359	379,739	(1.9)%
Jet fuel	167,638	186,675	(10.2)%
By-products (3)	17,948	11,876	51.1%
Total fuel products	$ 875,380	$ 910,959	(3.9)%
Total fuel products sales volume (in barrels)	11,466,000	10,292,000	11.4%
Average fuel products sales price per barrel	$ 69.84	$ 117.40	(40.5)%
Total sales	$ 1,846,600	$ 2,488,994	(25.8)%
Total sales volume (in barrels)	20,836,000	20,581,000	1.2%

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

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

(3) Represents by-products produced in connection with the production of fuels at the Shreveport refinery.

Specialty products segment sales in 2009 decreased 38.5% due primarily to a 32.4% decrease in the average selling price per barrel, with prices decreasing across all specialty product categories in response to the 40.7% decrease in the average cost of crude oil per barrel from 2008. In addition, specialty products segment volumes sold decreased by 8.9% from approximately 10.3 million barrels in 2008 to 9.4 million barrels in 2009. This decrease is due primarily to lower demand for lubricating oils, solvents and waxes as a result of the economic downturn. Asphalt and other by-products sales volume increased slightly due to higher production of these products resulting from increased throughput of sour crude oil at our Shreveport refinery.

Fuel products segment sales in 2009 decreased 3.9% due to a 40.5% decrease in the average selling price per barrel as compared to a 41.1% decrease in the overall cost of crude oil per barrel, partially offset by an 11.4% increase in sales volume. Selling prices decreased across all fuel products categories. Fuel products sales volumes increased from approximately 10.3 million barrels in 2008 to 11.5 million barrels in 2009, due primarily to increases in diesel and jet fuel sales volume as a result of the startup of the Shreveport refinery expansion project during the second quarter of 2008. Further offsetting the decrease in selling prices was a $371.9 million increase in derivative gains on our fuel products cash flow hedges recorded in sales. Please read Gross Profit below for the net impact of our crude oil and fuel products derivative instruments designated as hedges.

Gross Profit. Gross profit decreased $80.8 million, or 31.8%, to $173.1 million in 2009 from $253.9 million in 2008. Gross profit for each of our specialty and fuel products segments was as follows:

	Year Ended December 31,		
	2009	2008	% Change
	(Dollars in thousands)		
Gross profit by segment:			
Specialty products	$ 141,577	$ 187,561	(24.5)%
Percentage of sales	14.6%	11.9%	
Specialty products gross profit per barrel	$ 15.11	$ 18.23	(17.1)%
Fuel products	$ 31,525	$ 66,322	(52.5)%
Percentage of sales	3.6%	7.3%	
Fuel products gross profit per barrel	$ 2.75	$ 6.44	(57.3)%
Total gross profit	$ 173,102	$ 253,883	(31.8)%
Percentage of sales	9.4%	10.2%	

The $80.8 million decrease in total gross profit includes a decrease in gross profit of $46.0 million in the specialty products segment and a $34.8 million decrease in gross profit in the fuel products segment.

The decrease in specialty products segment gross profit is due primarily to an 8.9% decrease in sales volume, as discussed above, as well as a 32.4% decrease in the average selling price per barrel partially offset by a 40.7% reduction in the cost of crude oil per barrel. Further lowering our gross profit was a reduction in the cost of sales benefit of $1.8 million in 2009 from the liquidation of lower cost inventory layers and decreased derivative gains of $21.4 million in 2009 as compared to 2008.

Fuel products segment gross profit was negatively impacted by a 40.5% decrease in the average fuel products selling price per barrel as compared to a 41.1% decrease in the crude oil cost per barrel, resulting in a reduction of approximately 36.4% in our gross profit per barrel. Also lowering fuel products gross profit was a reduction in the cost of sales benefit of $16.6 million in 2009 from the liquidation of lower cost inventory layers. Partially offsetting these decreases in gross profit were increased sales volumes of fuel products of 1.2 million barrels from 10.3 million barrels in 2008 to 11.5 million barrels in 2009 and increased derivative gains of $30.9 million from our crack spread cash flow hedges.

Selling, general and administrative. Selling, general and administrative expenses decreased $1.7 million, or 5.0%, to $32.6 million in 2009 from $34.3 million in 2008. This decrease is due primarily to reduced bad debt expense of $2.4 million.

Transportation. Transportation expenses decreased $16.7 million, or 19.8%, to $68.0 million in 2009 from $84.7 million in 2008. This decrease is due primarily to reduced sales volumes of lubricating oils, solvents and waxes as well as cost reductions achieved in 2009 from improvements in railcar leasing, lower fuel surcharges and variable rail rates being reduced on certain routes.

Realized gain (loss) on derivative instruments. Realized gain on derivative instruments increased $67.2 million to a gain of $8.3 million in 2009 from a $58.8 million loss in 2008. This increased gain is primarily the result of realized gains on our crack spread derivatives that were executed to lock in gains on a portion of our fuel products segment derivative hedging activity in 2009 with no comparable activity in 2008. In addition, we experienced significant losses in the third quarter of 2008 on derivatives used to hedge our specialty products segment crude oil purchases with no comparable activity in 2009.

Unrealized gain (loss) on derivative instruments. Unrealized gain on derivative instruments increased $20.3 million to $23.7 million in 2009 from $3.5 million in 2008. This increased gain is due primarily to the derivatives used to economically hedge our specialty products crude oil purchases experiencing significant losses in 2008 as market prices declined in the third quarter of 2008 with no comparable losses in 2009.

Gain on sale of mineral rights. We recorded a $5.8 million gain in 2008 resulting from the lease of mineral rights on the real property at our Shreveport and Princeton refineries to an unaffiliated third party, which was accounted for as a sale, with no comparable activity in 2009. We have retained a royalty interest in any future production associated with these mineral rights.

Liquidity and Capital Resources

Our principal sources of cash have historically included cash flow from operations, proceeds from public equity 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 and capital expenditures related to internal growth projects and acquisitions from third parties or affiliates. We expect to fund future capital expenditures with current cash flow from operations and borrowings under our existing revolving credit facility. Future internal growth projects or acquisitions may require expenditures in excess of our then-current cash flow from operations and borrowings under our existing revolving credit facility and may require us to issue debt or equity securities in public or private offerings or incur additional borrowings under bank credit facilities to meet those costs.

Cash Flows

We believe that we have sufficient liquid assets, cash flow from operations and borrowing capacity to meet our financial commitments, debt service obligations, and anticipated capital expenditures. However, we are subject to business and operational risks that could materially adversely affect our cash flows. A material decrease in our cash flow from operations including a significant, sudden decrease in crude oil prices would likely produce a corollary material adverse effect on our borrowing capacity under our revolving credit facility and potentially our ability to comply with the covenants under our credit facilities. A significant, sudden increase in crude oil prices, if sustained, would likely result in increased working capital requirements which would be funded by borrowings under our revolving credit facility.

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

	Year Ended December 31,		
	2010	**2009**	**2008**
		(In thousands)	
Net cash provided by operating activities	$ 134,143	$ 100,854	$ 130,341

Net cash used in investing activities	$ (34,759)	$ (22,714)	$ (480,461)
Net cash provided by (used in) financing activities	$ (99,396)	$ (78,139)	$ 350,133

Operating Activities. Operating activities provided $134.1 million in cash during 2010 compared to $100.9 million during 2009. The increase in cash provided by operating activities is due primarily to reduced working capital needs in 2010 providing $26.0 million in cash compared to 2009 working capital changes using $14.8 million. This improvement is due primarily to improved payment terms with suppliers, offset by increases in both accounts receivable and inventories from higher crude oil prices.

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Operating activities provided $100.9 million in cash during 2009 compared to $130.3 million during 2008. The decrease in cash provided by operating activities during 2009 is due primarily to increased working capital requirements of $19.2 million resulting from the LyondellBasell Agreements as well as rising crude oil prices increasing our working capital requirements, partially offset by increased net income of $17.3 million.

Investing Activities. Cash used in investing activities increased to $34.8 million in 2010 compared to $22.7 million in 2009 due primarily to increased capital expenditures in 2010 compared to 2009.

Cash used in investing activities decreased to $22.7 million during 2009 compared to $480.5 million during 2008. This decrease is due primarily to the acquisition of Penreco for $269.1 million and spending on the Shreveport expansion project in 2008 of $119.6 million, with no comparable activity in 2009. Also decreasing the use of cash for investing activities in 2009 was the early settlement in 2008 of $49.7 million of derivative instruments related to 2008 and 2009 utilized to economically hedge the risk of rising crude oil prices with no comparable activity in 2009.

Financing Activities. Cash used in financing activities was $99.4 million during 2010 compared to $78.1 million during 2009. This increased use of cash is due primarily to proceeds received from our December 2009 public equity offering of approximately $52.3 million, including $1.1 million of contributions received from our general partner, with only $0.8 million of proceeds received in early 2010 from the exercise of the underwriter s overallotment option on our December 2009 public equity offering in addition to increased distributions of $6.5 million in 2010 as compared to 2009 due to higher amounts of outstanding units and an increase in our distribution per unit. Partially offsetting these increases is decreased net repayments of revolver borrowings of $33.6 million in 2010 as compared to 2009.

Cash used in financing activities was $78.1 million during 2009 compared to cash provided of $350.1 million during 2008. This change is due primarily to proceeds from borrowings under the new senior secured term loan credit facility of $385.0 million along with associated debt issuance costs incurred during 2008 with no comparable activity in 2009. The increased use of cash was also due to net repayments on the revolving credit facility of $62.6 million compared to net borrowings of $95.6 million in 2008, due primarily to final spending on the Shreveport refinery expansion project in 2008. Partially offsetting the increased use of cash were the proceeds received from our December 2009 public equity offering of approximately $52.3 million, including $1.1 million of contributions received from our general partner.

On January 14, 2011, the Company declared a quarterly cash distribution of $0.47 per unit on all outstanding units, or $16.9 million, for the quarter ended December 31, 2010. The distribution was paid on February 14, 2011 to unitholders of record as of the close of business on February 4, 2011. This quarterly distribution of $0.47 per unit equates to $1.88 per unit, or $67.7 million on an annualized basis.

Capital Expenditures

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

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

	Year Ended December 31, 2010	2009	2008
	(In thousands)		
Capital improvement expenditures	$ 10,656	$ 8,013	$ 161,398
Replacement capital expenditures	14,700	12,149	4,555
Environmental capital expenditures	9,645	3,359	1,749
Total	$ 35,001	$ 23,521	$ 167,702

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We anticipate that future capital expenditure requirements will be provided primarily through cash from operations and available borrowings under our revolving credit facility. In 2009 and 2010, we limited our overall capital expenditures to required environmental expenditures, necessary replacement capital expenditures to maintain our facilities and minor capital improvement projects to reduce energy costs, improve finished product quality and improve finished product yields. We estimate our replacement and environmental capital expenditures will average approximately $5.0 million per quarter in 2011 with total capital expenditures below 2010 levels. These estimated amounts for 2011 include a portion of the $11.0 million to $15.0 million in environmental projects required by our settlement with the LDEQ under the Small Refinery and Single Site Refining Initiative . Please read Items 1 and 2 Business and Properties Environmental, Health and Safety Matters Air for additional information.

Debt and Credit Facilities

As of December 31, 2010, our credit facilities consist of:

- a $375.0 million senior secured revolving credit facility, subject to borrowing base restrictions, with a standby letter of credit sublimit of $300.0 million; and

- a $435.0 million senior secured first lien credit facility consisting of a $385.0 million term loan facility and a $50.0 million letter of credit facility to support crack spread hedging. In connection with the execution of the above senior secured first lien credit facility, we incurred total debt issuance costs of $23.4 million, including $17.4 million of issuance discounts.

Borrowings under the amended revolving credit facility are limited to a borrowing base that is determined based on advance rates of percentages of eligible accounts receivable and inventory (as defined by 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 borrowing base at December 31, 2010 was $247.0 million. The borrowing base cannot exceed the total commitments of the lender group. The lender group under our revolving credit facility is comprised of a syndicate of nine lenders with total commitments of $375.0 million. Currently, the largest member of our bank group provides a commitment for $87.5 million. The smallest commitment is $15 million and the median commitment is $42.5 million. In the event of a default by one of the lenders in the syndicate, the total commitments under the revolving credit facility would be reduced by the defaulting lenders commitment, unless another lender or a combination of lenders increase their commitments to replace the defaulting lender. In the alternative, the revolving credit facility also permits us to replace a defaulting lender. Although we do not expect any current lenders to default under the revolving credit facility, we can provide no assurance that lender defaults will not occur. Also, our borrowing base at December 31, 2010 was $247.0 million; thus, we would have to experience defaults in commitments totaling $128.0 million from our lender group before such defaults would impact our liquidity as of December 31, 2010. Accordingly, at least three of our nine lenders would have to default in order for our liquidity position as of December 31, 2010 under the revolving credit facility to be adversely impacted.

The revolving credit facility, which is our primary source of liquidity for cash needs in excess of cash generated from operations, currently bears interest at prime plus a basis points margin or LIBOR plus a basis points margin, at our option. This margin is currently at 50 basis points for prime and 200 basis points for LIBOR; however, it fluctuates based on measurement of our Consolidated Leverage Ratio discussed below. The revolving credit facility, which matures in January 2013, has a first priority lien on our cash, accounts receivable and inventory and a second priority lien on our fixed assets. On December 31, 2010, we had availability on our revolving credit facility of $145.5 million, based upon a $247.0 million borrowing base, $90.7 million in outstanding standby letters of credit, and outstanding borrowings of $10.8 million. The improvement in our availability under our revolving credit facility of approximately $38.2 million from December 31, 2009 to December 31, 2010 is due primarily to increased cash flow from operations.

Amounts outstanding on our revolving credit facility do materially fluctuate during each quarter due to normal changes in working capital, payments of quarterly distributions to unitholders and debt service costs. Specifically, the amount borrowed under our revolving credit facility is typically at its highest level after we pay for the majority of our crude oil supplies on the 20th day of every month per standard industry terms. The maximum revolving credit facility borrowings during the fourth quarter of 2010 was $107.2 million. Nonetheless, our availability on our revolving credit facility during the peak borrowing days of a quarter has been ample to support our operations and service upcoming requirements. During the quarter ended December 31, 2010, availability for additional borrowings under our revolving credit facility was approximately $78.6 million at its lowest point. We believe that we will continue to have sufficient cash flow from operations and borrowing availability under our revolving credit facility to meet our financial commitments, minimum quarterly distributions to our unitholders, debt service obligations, credit agreement covenants, contingencies 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 or a significant, sustained decline in crude oil prices would likely produce a corollary material adverse effect on our borrowing capacity under our revolving credit facility and potentially have a material adverse effect on our ability to comply with the covenants under our credit facilities. Substantial declines in crude oil prices, if sustained, may materially diminish our borrowing base which is based, in part, on the value of our crude oil inventory and could result in a material reduction in our borrowing capacity under our revolving credit facility.

The term loan facility bears interest at a rate of LIBOR plus 400 basis points or prime plus 300 basis points, at our option. Management has historically kept the outstanding balance on a LIBOR basis; however, that decision is evaluated every three months to determine if a portion should be converted back to the prime rate. Each lender under this facility has a first priority lien on our fixed assets and a second priority lien on our cash, accounts receivable and inventory. Our term loan facility matures in January 2015. Under the terms of our term loan facility, we applied a portion of the net proceeds from the term loan to the acquisition of Penreco. We are required to make mandatory repayments of approximately $1.0 million at the end of each fiscal quarter, beginning with the fiscal quarter ended March 31, 2008 and ending with the fiscal quarter ending September 30, 2014, with the remaining balance due at maturity on January 3, 2015.

Our letter of credit facility to support crack spread hedging bears interest at a rate of 4.0% and is secured by a first priority lien on our fixed assets. We have issued a letter of credit in the amount of $50.0 million, the full amount available under this letter of credit facility, to one counterparty. As long as this first priority lien is in effect and the counterparty remains the beneficiary of the $50.0 million letter of credit, we will have no obligation to post additional cash, letters of credit or other collateral with the counterparty to provide additional credit support for a mutually-agreed maximum volume of executed crack spread hedges. In the event the counterparty s exposure to us exceeds $100.0 million, we would be required to post additional credit support with the counterparty to enter into additional crack spread hedges up to the aforementioned maximum volume. In addition, we have other crack spread hedges in place with other approved counterparties under the letter of credit facility whose credit exposure to us is also secured by a first priority lien on our fixed assets, subject to certain conditions.

The credit facilities require us to satisfy certain financial and other covenants, including:

	Requirement	**Actual Level at December 31, 2010**
Consolidated Leverage Ratio	< 3.75 to 1	2.90 to 1
Consolidated Interest Coverage Ratio	> 2.75 to 1	4.22 to 1

Our credit facilities permit us to make distributions to our unitholders as long as we are not in default and would not be in default following the distribution. Under the credit facilities, we are obligated to comply with certain financial covenants requiring us to maintain a Consolidated Leverage Ratio of no more than 3.75 to 1 and a Consolidated Interest Coverage Ratio of no less than 2.75 to 1 (as of the end of each fiscal quarter and after giving effect to a proposed distribution or other restricted payments as defined in the credit agreements) and Availability (as such term is defined in our credit agreements) of at least $35.0 million (after giving effect to a proposed distribution or other restricted payments as defined in the credit agreements). The Consolidated Leverage Ratio is defined under our credit agreements to mean the ratio of our Consolidated Debt (as defined in the credit agreements) as of the last day of any fiscal quarter to our Adjusted EBITDA (as defined below) for the last four fiscal quarter periods ending on such date. The Consolidated Interest Coverage Ratio is defined as the ratio of Consolidated EBITDA for the last four fiscal quarters to Consolidated Interest Charges for the same period. Adjusted EBITDA means Consolidated EBITDA as defined in our credit facilities to mean, for any period: (1) net income plus (2)(a) interest expense; (b) taxes; (c) depreciation and amortization; (d) unrealized losses from mark to market accounting for hedging activities; (e) unrealized items decreasing net income (including the non-cash impact of restructuring, decommissioning and asset impairments in the periods presented); (f) other non-recurring expenses reducing net income which do not represent a cash item for such period; and (g) all non-recurring restructuring charges associated with the acquisition of Penreco on January 3, 2008 minus (3)(a) tax credits; (b) unrealized items increasing net income (including the non-cash impact of restructuring, decommissioning and asset impairments in the periods presented); (c) unrealized gains from mark to market accounting for hedging activities; and (d) other non-recurring expenses and unrealized items that reduced net income for a prior period, but represent a cash item in the current period. In addition, if at any time that our borrowing capacity under our revolving credit facility falls below $35.0 million, meaning we have Availability of less than $35.0 million, we will be required to immediately measure and maintain a Fixed Charge Coverage Ratio of at least 1 to 1 (as of the end of each fiscal quarter). The Fixed Charge Coverage Ratio is defined under our credit agreements to mean the ratio of (a) Adjusted EBITDA minus Consolidated Capital Expenditures minus Consolidated Cash Taxes, to (b) Fixed Charges (as each such term is defined in our credit agreements).

Compliance with the financial covenants pursuant to our credit agreements is measured quarterly based upon performance over the most recent four fiscal quarters, and as of December 31, 2010, we believe we were in compliance with all financial covenants under our credit agreements and have adequate liquidity to conduct our business. Even though our liquidity and leverage improved during fiscal year 2010, we are continuing to take steps to ensure that we continue to meet the requirements of our credit agreements and currently believe that we will be in compliance for all future measurement dates, although assurances cannot be made regarding our future compliance with these covenants.

Failure to achieve our anticipated results may result in a breach of certain of the financial covenants contained in our credit agreements. If this occurs, we will enter into discussions with our lenders to either modify the terms of the existing credit facilities or obtain waivers of non-compliance with such covenants. There can be no assurances of the timing of the receipt of any such modification or waiver, the term or costs associated therewith or our ultimate ability to obtain the relief sought. Our failure to obtain a waiver of non-compliance with certain of the financial covenants or otherwise amend the credit facilities would constitute an event of default under our credit facilities and would permit the lenders to pursue remedies. These remedies could include acceleration of maturity under our credit facilities and limitations on, or the elimination of, our ability to make distributions to our unitholders. If our lenders accelerate maturity under our credit facilities, a significant portion of our indebtedness may become due and payable immediately. We might not have, or be able to obtain, sufficient funds to make these accelerated payments. If we are unable to make these accelerated payments, our lenders could seek to foreclose on our assets.

In addition, our credit agreements contain various covenants that limit our ability, among other things, to: incur indebtedness; grant liens; make certain acquisitions and investments; make capital expenditures above specified amounts; redeem or prepay other debt or make other restricted payments such as distributions to unitholders; enter into transactions with affiliates; enter into a merger, consolidation or sale of assets; and cease our refining margin hedging program (our lenders have required us to obtain and maintain derivative contracts for fuel products margins in our fuel products segment for a rolling period of 1 to 12 months for at least 60% and no more than 90% of our anticipated fuels production, and for a rolling 13-24 months forward for at least 50% and no more than 90% of our anticipated fuels production).

If an event of default exists under our credit agreements, the lenders will be able to accelerate the maturity of the credit facilities and exercise other rights and remedies. An event of default is defined as 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 credit agreement or other loan documents, subject to certain grace periods; payment defaults in respect of other indebtedness; cross-defaults in other indebtedness if the effect of such default is to cause the acceleration of such indebtedness under any material agreement if such default could have a material adverse effect on us; bankruptcy or insolvency events; monetary judgment defaults; asserted invalidity of the loan documentation; and a change of control in us.

On July 12, 2010, we announced that we and Calumet Finance Corp., our wholly owned subsidiary, intended to offer for sale in a private placement under Rule 144A to eligible purchasers $450 million in aggregate principal amount of senior unsecured notes. We viewed the offering as an opportunity, but not a necessity, to refinance our existing term loan facility with longer-term unsecured notes. However, on July 22, 2010, we announced that, due to market conditions, we opted to not move forward with the contemplated senior notes offering at that time. We intend to continue monitoring the capital markets for the opportunity to complete a debt refinancing transaction under appropriate market conditions.

Contractual Obligations and Commercial Commitments

A summary of our total contractual cash obligations as of December 31, 2010 is as follows:

	Payments Due by Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
			(In thousands)		
Operating Activities:					
Interest on long-term debt at contractual rates	$ 70,458	$ 20,026	$ 34,908	$ 15,524	$
Operating lease obligations (1)	36,339	12,572	16,355	6,644	768
Letters of credit (2)	140,725	90,725	50,000		
Purchase commitments (3)	1,006,114	560,015	315,264	130,835	
Pension obligations	10,063	1,763	4,300	3,500	500
Employment agreements (4)	742	371	371		
Financing Activities:					
Capital lease obligations	1,781	994	787		
Long-term debt obligations, excluding capital lease obligations	378,217	3,850	18,532	355,835	
Total obligations	$ 1,644,439	$ 690,316	$ 440,517	$ 512,338	$ 1,268

(1) We have various operating leases for the use of land, storage tanks, pressure stations, railcars, equipment, precious metals and office facilities that extend through August 2015.

(2) Letters of credit supporting crude oil purchases, precious metals leasing and hedging activities.

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

(4) Annual compensation under the employment agreement of F. William Grube, chief executive officer and vice chairman of the board of our general partner.

In connection with the closing of the acquisition of Penreco on January 3, 2008, we entered into a feedstock purchase agreement with ConocoPhillips related to the LVT unit at its Lake Charles, Louisiana refinery (the LVT Feedstock Agreement). Pursuant to the LVT Feedstock Agreement, ConocoPhillips is obligated to supply a minimum quantity (the Base Volume) of feedstock for the LVT unit for a term of ten years. Based upon this minimum supply quantity, we expect to purchase $64.9 million of feedstock for the LVT unit in each fiscal year of the term based on pricing estimates as of December 31, 2010. This amount is not included in the table above. If the Base Volume is not supplied at any point during the first five years of the ten-year term, a penalty for each gallon of shortfall must be paid to us as liquidated damages.

Off-Balance Sheet Arrangements

We have no material off-balance sheet arrangements.

Critical Accounting Policies and Estimates

Our discussion and analysis of results of operations and financial condition are based upon our consolidated financial statements for the years ended December 31, 2010, 2009 and 2008. 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 to our consolidated financial statements in Item 8 Financial Statements and Supplementary Data of this Annual Report. 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, 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.

Inventories

The cost of inventories is determined using the last-in, first-out (LIFO) method and valued at the lower of cost or market. Costs include crude oil and other feedstocks, labor and refining overhead costs. We review our inventory balances quarterly for excess inventory levels or obsolete products and write down, if necessary, the inventory to net realizable value. The replacement cost of our inventory, based on current market values, would have been $55.9 million and $30.4 million higher at December 31, 2010 and 2009, respectively.

Fair Value of Financial Instruments

In accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification Statement (ASC) 815-10, *Derivatives and Hedging* (formerly Statement of Financial Accounting Standards (SFAS) No. 161, *Derivative Instruments and Hedging Activities*), we recognize all derivative transactions as either assets or liabilities at fair value on the consolidated balance sheets. We utilize third party valuations and published market data to determine the fair value of these derivatives and thus does not directly rely on market indices. We perform an independent verification of the third party valuation statements to validate inputs for reasonableness and complete a comparison of implied crack spread mark-to-market valuations among our counterparties.

Our derivative instruments, consisting of derivative liabilities of $32.8 million as of December 31, 2010, are valued at Level 1, Level 2, and Level 3 fair value measurement under ASC 820-10, *Fair Value Measurements and Disclosures* (formerly SFAS No. 157, *Fair Value Measurements),* depending upon the degree by which inputs are observable. We recorded realized and unrealized losses on derivative instruments of $7.7 million and $15.8 million, respectively, on our derivative instruments in 2010. The decrease in the fair market value of our outstanding derivative instruments from a net asset of $26.1 million as of December 31, 2009 to a liability of $32.8 million as of December 31, 2010 was due primarily to $28.9 million in settlements of fuel products derivative instruments outstanding as of December 31, 2009, in addition to $18.5 million in liabilities related to new derivative instruments. We believe that the fair values of our derivative instruments may diverge materially from the amounts currently recorded to fair value at settlement due to the volatility of commodity prices.

Holding all other variables constant, we expect a $1 increase in the applicable commodity prices would change our recorded mark-to-market valuation by the following amounts based upon the volumes hedged as of December 31, 2010:

	In millions
Crude oil swaps	$ 11.5
Diesel swaps	$ (3.9)
Jet fuel swaps	$ (6.6)
Gasoline swaps	$ (0.9)

We enter into crude oil, gasoline, and diesel hedges to hedge an implied crack spread in our fuel products segment. Therefore, any increase in crude oil swap mark-to-market valuation due to changes in commodity prices will generally be accompanied by a decrease in gasoline and diesel swap mark-to-market valuation.

In addition, we measure our investments associated with the Company s non-contributory defined benefit plan (Pension Plan) on a recurring basis. The Company s investments associated with its Pension Plan consist of mutual funds that are publicly traded and for which market prices are readily available, thus these investments are categorized as Level 1.

Recent Accounting Pronouncements

In December 2008, the FASB issued pronouncements under ASC 715-20, *Compensation-Retirement Benefits-Defined Benefit Plans (*formerly FSP FAS 132R-1, *Employers Disclosures about Postretirement Benefit Plan Assets*). ASC 715-20 replaces the requirement to disclose the percentage of the fair value of total plan assets with a requirement to disclose the fair value of each major asset category. ASC 715-20 also requires additional disclosure regarding the level of the plan assets within the fair value hierarchy according to ASC 820-10, *Fair Value Measurements and Disclosures* (formerly SFAS No. 157, *Fair Value Measurements*), and a reconciliation of activity for any plan assets being measured using unobservable inputs as defined in ASC 715-20. ASC 715-20 is effective for fiscal years ending after December 15, 2009. The adoption of ASC 715-20 did not have a material impact on the Company s financial position, results of operations, or cash flows.

In January 2010, the FASB issued ASU No. 2010-06, *Disclosures About Fair Value Measurements* (ASU 2010-06), which amends ASC No. 820, *Fair Value Measurements and Disclosures* to add new requirements for disclosures about transfers into and out of Levels 1 and 2 and separate disclosures about purchases, sales, issuances, and settlements relating to Level 3 measurements. ASU 2010-06 also clarifies existing fair value disclosures about the level of disaggregation and about inputs and valuation techniques used to measure fair value. ASU 2010-06 is effective for the first reporting period (including interim periods) beginning after December 15, 2009. The Company adopted ASU 2010-06 effective January 1, 2010; however, the Company s adoption of the ASU did not have a material effect on the Company s financial position, results of operations or cash flows.

In December 2010, the FASB issued ASU No. 2010-28, *When to Perform Step 2 of the Goodwill Impairment Test for Reporting Units with Zero or Negative Carrying Amounts* (ASU 2010-28), which amends ASC No. 830, *Intangibles Goodwill and Other* to modify Step 1 of the evaluation of goodwill impairment for reporting units with zero or negative carrying amounts to require that Step 2 of the impairment test be performed to measure the amount of any impairment loss when it is more likely than not that a goodwill impairment exits. ASU 2010-28 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2010, with early adoption not permitted. The Company does not expect the adoption of ASU 2010-28 to have a material impact on the Company s financial position, results of operations, or cash flows.

In December 2010, the FASB issued ASU No. 2010-29, *Disclosures of Supplementary Pro Forma Information for Business Combinations* (ASU 2010-29), which amends ASC No. 805, *Business Combinations,* to expand the requirements for supplemental pro forma disclosures to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. ASU 2010-29 is effective for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010, and should be applied prospectively. The Company will apply the provisions of ASU 2010-29 for all future business combinations.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk*

Commodity Price Risk

Consistent with prior years, both our profitability and our cash flows are affected by volatility in prevailing crude oil, gasoline, diesel, jet fuel, and natural gas prices. The primary purpose of our commodity risk management activities is to hedge our exposure to price risks associated with the cost of crude oil and natural gas and sales prices of our fuel products.

Crude Oil Price Volatility

We are exposed to significant fluctuations in the price of crude oil, our principal raw material. Given the historical volatility of crude oil prices, this exposure can significantly impact product costs and gross profit. Holding all other variables constant, and excluding the impact of our current hedges, we expect a $1.00 change in the per barrel price of crude oil would change our specialty product segment cost of sales by $10.8 million and our fuel product segment cost of sales by $9.6 million based on our sales volumes for 2010.

Crude Oil Hedging Policy

Because we typically do not set prices for our specialty products in advance of our crude oil purchases, we can generally take into account the cost of crude oil in setting specialty products prices. However, as evidenced during the prior three years when crude oil prices ranged from a low of approximately $34 per barrel to a high of approximately $145 per barrel, we are not always able to adjust our selling prices as quickly as increases in the price of crude oil. Due to this lack of correlation between our specialty products selling prices and crude oil in periods of high volatility, we further manage our exposure to fluctuations in crude oil prices in our specialty products segment through the use of derivative instruments, which can include both swaps and options, generally executed in the over-the-counter (OTC) market. Our policy is generally to enter into crude oil derivative contracts that match our expected future cash outflows for up to 70% of our anticipated crude oil purchases related to our specialty products production. While our policy generally requires that these positions be short term in nature and expire within three to nine months from execution, we may execute derivative instruments for up to two years forward, if a change in crude oil price risks supports lengthening our position. Our fuel products sales are based on market prices at the time of sale. Accordingly, in conjunction with our fuel products hedging policy discussed below, we enter into crude oil derivative contracts related to our fuel products segment for up to five years and no more than 75% of our fuel products sales on average for each fiscal year.

Natural Gas Price Volatility

Since natural gas purchases comprise a significant component of our cost of sales, changes in the price of natural gas also significantly affect our profitability and our cash flows. Holding all other cost and revenue variables constant, and excluding the impact of our current hedges, we expect a $0.50 change per MMBtu (one million British Thermal Units) in the price of natural gas would change our cost of sales by $4.0 million based on our results for the year ended December 31, 2010.

Natural Gas Hedging Policy

We enter into derivative contracts to manage our exposure to natural gas prices. Our policy is generally to enter into natural gas swap contracts during the summer months for up to approximately 50% of our anticipated natural gas requirements for the upcoming fall and winter months with time to expiration not to exceed three years.

Fuel Products Selling Price Volatility

We are exposed to significant fluctuations in the prices of gasoline, diesel, and jet fuel. Given the historical volatility of gasoline, diesel, and jet fuel prices, this exposure can significantly impact sales and gross profit.

Holding all other variables constant, and excluding the impact of our current hedges, we expect that a $1 change in the per barrel selling price of gasoline, diesel, and jet fuel would change our fuel products segment sales by $9.6 million based on our results for the year ended December 31, 2010.

Fuel Products Hedging Policy

In order to manage our exposure to changes in gasoline, diesel, and jet fuel selling prices, our policy is generally to enter into derivative contracts to hedge our fuel products sales for a period no greater than five years forward and for no more than 75% of anticipated fuels sales on average for each fiscal year, which is consistent with our crude oil purchase hedging policy for our fuel products segment discussed above. We believe this policy lessens the volatility of our cash flows. In addition, in connection with our credit facilities, our lenders require us to hedge our fuel products margins for a rolling period of 1 to 12 months forward for at least 60% and no more than 90% of our anticipated fuels production, and for a rolling 13 to 24 months forward for at least 50% and no more than 90% of our anticipated fuels production. As of December 31, 2010, we were over 60% hedged for the forward 12 month period and over 50% hedged for the forward 24 month period. We are currently hedging in calendar year 2013, with no positions currently in 2014 or 2015.

The unrealized gain or loss on derivatives at a given point in time is not necessarily indicative of the results realized when such contracts mature. The decrease in the fair market value of our outstanding derivative instruments from a net asset of $26.1 million as of December 31, 2009 to a liability of $32.8 million as of December 31, 2010 was due primarily to increases in the forward market values of fuel products margins, or cracks spreads, relative to our hedged fuel products margins and settlement of derivatives in 2010 that resulted in realized gain. Please read Note 2 Summary of Significant Accounting Policies Derivatives in the notes to our consolidated financial statements under Item 8 Financial Statements and Supplementary Data for a discussion of the accounting treatment for the various types of derivative transactions, and a further discussion of our hedging policies.

Interest Rate Risk

Our profitability and cash flows are affected by changes in interest rates, specifically LIBOR and prime rates, which is consistent with prior years. The primary purpose of our interest rate risk management activities is to hedge our exposure to changes in interest rates. Our policy is generally to enter into interest rate swap agreements to hedge up to 75% of its interest rate risk under our term loan agreement.

We are exposed to market risk from fluctuations in interest rates. As of December 31, 2010, we had approximately $378.2 million of variable rate debt. Holding other variables constant (such as debt levels), a one hundred basis point change in interest rates on our variable rate debt as of December 31, 2010 would be expected to have an impact on net income and cash flows for 2010 of approximately $3.8 million.

We have a $375.0 million revolving credit facility as of December 31, 2010, bearing interest at the prime rate or LIBOR, at our option, plus the applicable margin. We had borrowings of $10.8 million outstanding under this facility as of December 31, 2010, bearing interest at the prime rate or LIBOR, at our option, plus the applicable margin.

Existing Interest Rate Derivative Instruments

In 2008, the Company entered into a forward swap contract to manage interest rate risk related to a portion of its current variable rate senior secured first lien term loan which closed January 3, 2008. The Company hedged the future interest payments related to $150.0 million and $50.0 million of the total outstanding term loan indebtedness in 2009 and 2010, respectively, pursuant to this forward swap contract. This swap contract is designated as a cash flow hedge of the future payment of interest with three-month LIBOR fixed at 3.09% and 3.66% per annum in 2009 and 2010, respectively.

In 2009, the Company hedged the future interest payments related to $200.0 million of the total outstanding term loan indebtedness for the period from February 15, 2010 to February 15, 2011. This swap contract is designated as a cash flow hedge of the future payment of interest with three-month LIBOR fixed at an average rate during the hedge period of 0.94%.

During 2010, the Company entered into forward swap contracts to manage interest rate risk related to a portion of its current variable rate senior secured first lien term loan. The Company hedged the future interest payments related to $100.0 million of the total outstanding term loan indebtedness for the period from February 15, 2011 to February 15, 2012 pursuant to these forward swap contracts. These swap contracts are designated as cash flow hedges of the future payments of interest with three-month LIBOR fixed at an average rate during the hedge period of 2.03%.

Existing Commodity Derivative Instruments

Fuel Products Segment

As a result of our fuel products hedging activity, we recorded a loss of $67.7 million and a gain of $81.6 million, to sales and cost of sales, respectively, in the consolidated statements of operations for 2010. As of December 31, 2010 we had not provided any cash margin in credit support to our hedging counterparties. As of February 18, 2011, we had provided $23.2 million in credit support to our hedging counterparties due to the decrease in the fair market value of our derivative instruments since December 31, 2010.

The following tables provide information about our derivative instruments related to our fuel products segment as of December 31, 2010:

Crude Oil Swap Contracts by Expiration Dates	Barrels Purchased	BPD	Average Swap ($/Bbl)
First Quarter 2011	1,215,000	13,500	$ 75.32
Second Quarter 2011	1,729,000	19,000	76.62
Third Quarter 2011	1,610,000	17,500	77.38
Fourth Quarter 2011	1,334,000	14,500	77.71
Calendar Year 2012	5,535,000	15,123	86.30
Totals	11,423,000		
Average price			$ 81.41

Diesel Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
First Quarter 2011	630,000	7,000	$ 89.57
Second Quarter 2011	637,000	7,000	89.57
Third Quarter 2011	552,000	6,000	91.74
Fourth Quarter 2011	552,000	6,000	91.74
Calendar Year 2012	1,560,000	4,262	99.27
Totals	3,931,000		
Average price			$ 94.03

Average

Jet Fuel Swap Contracts by Expiration Dates	Barrels Sold	BPD	Swap ($/Bbl)
First Quarter 2011	405,000	4,500	$ 86.12
Second Quarter 2011	819,000	9,000	89.58
Third Quarter 2011	920,000	10,000	89.86
Fourth Quarter 2011	644,000	7,000	89.21
Calendar Year 2012	3,838,500	10,480	99.78
Totals	6,626,500		
Average price			$ 95.28

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Gasoline Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
First Quarter 2011	180,000	2,000	$ 81.84
Second Quarter 2011	273,000	3,000	82.66
Third Quarter 2011	138,000	1,500	85.50
Fourth Quarter 2011	138,000	1,500	85.50
Calendar Year 2012	136,500	373	89.04
Totals	865,500		
Average price			$ 84.40

The following table provides a summary of these derivatives and implied crack spreads for the crude oil, diesel and gasoline swaps disclosed above, all of which are designated as hedges.

Swap Contracts by Expiration Dates	Barrels Sold	BPD	Implied Crack Spread ($/Bbl)
First Quarter 2011	1,215,000	13,500	$ 11.96
Second Quarter 2011	1,729,000	19,000	11.87
Third Quarter 2011	1,610,000	17,500	12.75
Fourth Quarter 2011	1,334,000	14,500	12.16
Calendar Year 2012	5,535,000	15,123	13.07
Totals	11,423,000		
Average price			$ 12.62

Jet Fuel Put Spread Contracts

At December 31, 2010, the Company had the following jet fuel put options related to jet fuel crack spreads in its fuel products segment, none of which are designated as hedges.

Jet Fuel Put Option Crack Spread Contracts by Expiration Dates	Barrels	BPD	Average Sold Put ($/Bbl)	Average Bought Put ($/Bbl)
First Quarter 2011	630,000	7,000	$ 4.00	$ 6.00
Fourth Quarter 2011	184,000	2,000	4.75	7.00
Totals	814,000			
Average price			$ 4.17	$ 6.23

Specialty Products Segment

As a result of our specialty products crude oil hedging activity, we recorded a loss of $5.3 million, to realized loss on derivative instruments in the consolidated statements of operations for 2010. As of December 31, 2010 and February 18, 2011, we had not provided any cash margin in credit support to any of our hedging counterparties. At December 31, 2010, the Company had the following crude oil swap derivatives related to crude oil purchases in its specialty products segment, none of which are designated as hedges. As a result of these derivatives not being designated as hedges, the Company recognized $0.7 million of gain in unrealized gain (loss) on derivative instruments in the consolidated statements of operations in 2010.

Crude Oil Swap Contracts by Expiration Dates	**Barrels Purchased**	**BPD**	**Average Swap ($/Bbl)**
February 2011	33,600	1,200	$ 83.10
March 2011	37,200	1,200	83.55
Totals	70,800		
Average price			$ 83.34

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Item 8. *Financial Statements and Supplementary Data*

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, 2010 and 2009, and the related consolidated statements of operations, partners capital, and cash flows for each of the three years in the period ended December 31, 2010. 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 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 provide a reasonable basis for our opinion.

In our opinion, 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, 2010 and 2009, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2010, 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, 2010, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 18, 2011 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Indianapolis, Indiana
February 18, 2011

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CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.

CONSOLIDATED BALANCE SHEETS

	Year Ended December 31, 2010	2009
	(In thousands, except unit data)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 37	$ 49
Accounts receivable:		
Trade, less allowance for doubtful accounts of $633 and $801, respectively	157,185	116,914
Other	776	5,854
	157,961	122,768
Inventories	147,110	137,250
Derivative assets		30,904
Prepaid expenses and other current assets	1,909	1,811
Deposits	2,094	6,861
Total current assets	309,111	299,643
Property, plant and equipment, net	612,433	629,275
Goodwill	48,335	48,335
Other intangible assets, net	29,666	38,093
Other noncurrent assets, net	17,127	16,510
Total assets	$ 1,016,672	$ 1,031,856
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Accounts payable	$ 146,730	$ 92,110
Accounts payable related party	27,985	17,866
Accrued salaries, wages and benefits	7,559	6,500
Taxes payable	7,174	7,551
Other current liabilities	16,605	6,114
Current portion of long-term debt	4,844	5,009
Derivative liabilities	32,814	4,766
Total current liabilities	243,711	139,916
Pension and postretirement benefit obligations	9,168	9,433
Other long-term liabilities	1,083	1,111
Long-term debt, less current portion	364,431	396,049
Total liabilities	618,393	546,509

Commitments and contingencies		
Partners capital:		
Common unitholders (22,213,778 units and 22,166,000 units, issued and outstanding at December 31, 2010 and 2009, respectively)	390,843	418,902
Subordinated unitholders (13,066,000 units, issued and outstanding at December 31, 2010 and 2009)	16,930	34,714
General partner s interest	18,125	19,087
Accumulated other comprehensive income (loss)	(27,619)	12,644
Total partners capital	398,279	485,347
Total liabilities and partners capital	$ 1,016,672	$ 1,031,856

See accompanying notes to consolidated financial statements.

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CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2010	2009	2008
	(In thousands, except per unit data)		
Sales	$ 2,190,752	$ 1,846,600	$ 2,488,994
Cost of sales	1,992,003	1,673,498	2,235,111
Gross profit	198,749	173,102	253,883
Operating costs and expenses:			
Selling, general and administrative	35,224	32,570	34,267
Transportation	85,471	67,967	84,702
Taxes other than income taxes	4,601	3,839	4,598
Other	1,963	1,366	1,576
Operating income	71,490	67,360	128,740
Other income (expense):			
Interest expense	(30,497)	(33,573)	(33,938)
Debt extinguishment costs			(898)
Realized gain (loss) on derivative instruments	(7,704)	8,342	(58,833)
Unrealized gain (loss) on derivative instruments	(15,843)	23,736	3,454
Gain on sale of mineral rights			5,770
Other	(147)	(3,929)	399
Total other expense	(54,191)	(5,424)	(84,046)
Income before income taxes	17,299	61,936	44,694
Income tax expense	598	151	257
Net income	$ 16,701	$ 61,785	$ 44,437
Allocation of net income:			
Net income	$ 16,701	$ 61,785	$ 44,437
Less:			
General partner s interest in net income	334	1,236	889
Holders of incentive distribution rights			
Net income available to limited partners	16,367	60,549	43,548
Weighted average limited partner units outstanding:			
Basic	35,335	32,372	32,232
Diluted	35,351	32,372	32,232
Common and subordinated unitholders basic and diluted net income per unit	$ 0.46	$ 1.87	$ 1.35

Cash distributions declared per common and subordinated unit	$ 1.84	$ 1.81	$ 1.98

See accompanying notes to consolidated financial statements.

CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF PARTNERS CAPITAL

	Accumulated Other Comprehensive Income (Loss)	General Partner	Partners Capital Limited Partners Common	Subordinated	Total
			(In thousands)		
Balance at January 1, 2008	$ (39,641)	$ 19,364	$ 375,925	$ 43,996	$ 399,644
Comprehensive income:					
Net income		889	25,895	17,653	44,437
Cash flow hedge loss reclassified to net income	(8,208)				(8,208)
Change in fair value of cash flow hedges	109,639				109,639
Defined benefit pension and retiree health benefit plans	(6,224)				(6,224)
Comprehensive income					139,644
Units repurchased for phantom unit grants			(115)		(115)
Amortization of vested phantom units			179		179
Distributions to partners		(2,320)	(37,949)	(25,871)	(66,140)
Balance at December 31, 2008	$ 55,566	$ 17,933	$ 363,935	$ 35,778	$ 473,212
Comprehensive income:					
Net income		1,236	38,094	22,455	61,785
Cash flow hedge gain reclassified to net income	(15,068)				(15,068)
Change in fair value of cash flow hedges	(29,371)				(29,371)
Defined benefit pension and retiree health benefit plans	1,517				1,517
Comprehensive income					18,863
Proceeds from public equity offering, net			51,225		51,225
Contribution from Calumet GP, LLC		1,102			1,102
Units repurchased for phantom unit grants			(164)		(164)
Amortization of vested phantom units			367		367
Distributions to partners		(1,184)	(34,555)	(23,519)	(59,258)
Balance at December 31, 2009	$ 12,644	$ 19,087	$ 418,902	$ 34,714	$ 485,347
Comprehensive loss:					
Net income		334	10,305	6,062	16,701

Cash flow hedge gain reclassified to net income	(11,104)				(11,104)
Change in fair value of cash flow hedges	(29,015)				(29,015)
Defined benefit pension and retiree health benefit plans	(144)				(144)
Comprehensive loss					(23,562)
Proceeds from public equity offering, net			793		793
Contribution from Calumet GP, LLC		18			18
Units repurchased for phantom unit grants			(248)		(248)
Amortization of vested phantom units			1,670		1,670
Distributions to partners		(1,314)	(40,579)	(23,846)	(65,739)
Balance at December 31, 2010	$ (27,619)	$ 18,125	$ 390,843	$ 16,930	$ 398,279

See accompanying notes to consolidated financial statements.

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CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2010	2009	2008
	(In thousands)		
Operating activities			
Net income	$ 16,701	$ 61,785	$ 44,437
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	64,151	65,407	59,261
Amortization of turnaround costs	10,006	7,256	2,468
Provision for doubtful accounts	74	(916)	1,448
Non-cash debt extinguishment costs			898
Unrealized (gain) loss on derivative instruments	15,843	(23,736)	(3,454)
Gain on sale of mineral rights			(5,770)
Loss on disposal of fixed assets	239	4,455	211
Other non-cash activities	1,104	1,441	1,501
Changes in assets and liabilities:			
Accounts receivable	(35,267)	(12,296)	45,042
Inventories	(9,860)	(18,726)	55,532
Prepaid expenses and other current assets	(98)	(8)	5,834
Derivative activity	2,990	8,531	41,757
Deposits	4,767	(2,840)	(4,000)
Other assets	(12,690)	(6,889)	(10,211)
Accounts payable	64,739	15,951	(103,136)
Accrued salaries, wages and benefits	1,059	(1,088)	(1,657)
Taxes payable	(377)	718	618
Other liabilities	11,171	576	(245)
Pension and postretirement benefit obligations	(409)	1,233	(193)
Net cash provided by operating activities	134,143	100,854	130,341
Investing activities			
Additions to property, plant and equipment	(35,001)	(23,521)	(167,702)
Acquisition of Penreco, net of cash acquired			(269,118)
Settlement of derivative instruments			(49,746)
Proceeds from sale of mineral rights			6,065
Proceeds from disposal of property, plant and equipment	242	807	40
Net cash used in investing activities	(34,759)	(22,714)	(480,461)
Financing activities			
Proceeds from borrowings revolving credit facility	1,015,485	805,361	1,424,732
Repayments of borrowings revolving credit facility	(1,044,553)	(868,000)	(1,329,150)
Repayments of borrowings prior term loan credit facilities			(30,099)
Proceeds from borrowings existing term loan credit facility			385,000
Repayments of borrowings existing term loan credit facility	(3,850)	(3,850)	(9,915)

Discount on existing term loan						(17,400)
Debt issuance costs						(9,633)
Payments on capital lease obligation		(1,302)		(1,542)		(618)
Proceeds from public equity offerings, net		793		51,225		
Contributions from Calumet GP, LLC		18		1,102		
Change in bank overdraft.				(3,013)		3,471
Common units repurchased for vested phantom unit grants		(248)		(164)		(115)
Distributions to partners		(65,739)		(59,258)		(66,140)
Net cash provided by (used in) financing activities		(99,396)		(78,139)		350,133
Net increase (decrease) in cash and cash equivalents		(12)		1		13
Cash and cash equivalents at beginning of year		49		48		35
Cash and cash equivalents at end of year	$	37	$	49	$	48
Supplemental disclosure of cash flow information						
Interest paid, net of capitalized interest	$	26,389	$	30,343	$	27,000
Income taxes paid	$	188	$	161	$	30
Supplemental disclosure of noncash financing and investing activities						
Equipment acquired under capital lease	$		$	1,659	$	171

See accompanying notes to consolidated financial statements.

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CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(dollars in thousands)

1. Description of the Business

Calumet Specialty Products Partners, L.P. (the Company) is a Delaware limited partnership. The general partner of the Company is Calumet GP, LLC, a Delaware limited liability company. As of December 31, 2010, the Company had 22,213,778 common units, 13,066,000 subordinated units, and 719,995 general partner units outstanding. The general partner owns 2% of the Company while the remaining 98% is owned by limited partners. The Company is engaged in the production and marketing of crude oil-based specialty lubricating oils, white mineral oils, solvents, petrolatums, waxes and fuels. The Company owns facilities located in Shreveport, Louisiana (Shreveport), Princeton, Louisiana (Princeton), Cotton Valley, Louisiana (Cotton Valley), Karns City, Pennsylvania (Karns City), and Dickinson, Texas (Dickinson), and a terminal located in Burnham, Illinois (Burnham).

2. Summary of Significant Accounting Policies

Consolidation

The consolidated financial statements of the Company include the accounts of Calumet Specialty Products Partners, L.P. and its wholly-owned operating subsidiaries, Calumet Lubricants Co., Limited Partnership, Calumet Sales Company Incorporated, Calumet Penreco, LLC and Calumet Shreveport, LLC. Calumet Shreveport, LLC s wholly-owned operating subsidiaries are Calumet Shreveport Fuels, LLC and Calumet Shreveport Lubricants & Waxes, LLC. All intercompany transactions and accounts have been eliminated.

Use of Estimates

The Company s financial statements are prepared in conformity with U.S. generally accepted accounting principles 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 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 includes all highly liquid investments with a maturity of three months or less at the time of purchase.

Inventories

The cost of inventories is determined 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.

Inventories consist of the following:

	December 31,	
	2010	**2009**

Raw materials	$ 12,885	$ 1,323
Work in process	49,006	51,304
Finished goods	85,219	84,623
	$ 147,110	$ 137,250

The replacement cost of these inventories, based on current market values, would have been $55,855 and $30,420 higher as of December 31, 2010 and 2009, respectively. During the years ended December 31, 2010, 2009

CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(dollars in thousands)

and 2008, the Company recorded $13,661, $18,375 and $5,446, respectively, of gains in cost of sales in the consolidated statements of operations due to the liquidation of lower cost inventory layers.

Accounts Receivable

The Company performs periodic credit evaluations of customers financial condition and generally does not require collateral. Accounts receivable are generally due within 30 to 45 days for the specialty products segment and 10 days for the fuel products segment. 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 credit experience and expected future trends. The activity in the allowance for doubtful accounts was as follows:

	December 31,		
	2010	**2009**	**2008**
Beginning balance	$ 801	$ 2,121	$ 786
Provision	(61)	(916)	1,448
Recoveries		11	
Write-offs, net	(107)	(415)	(113)
Ending balance	$ 633	$ 801	$ 2,121

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, consists of the following:

	December 31,	
	2010	**2009**
Land	$ 3,249	$ 3,249
Buildings and improvements (10 to 40 years)	6,848	6,713
Machinery and equipment (10 to 20 years)	770,973	740,656
Furniture and fixtures (5 to 10 years)	3,646	2,713
Assets under capital leases (1 to 4 years)	4,201	4,198
Construction-in-progress	7,673	9,400
	796,590	766,929

Less accumulated depreciation	(184,157)	(137,654)
	$ 612,433	$ 629,275

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 the years ended December 31, 2010, 2009 and 2008, the Company incurred $30,886, $34,170 and $41,159, respectively, of interest expense of which $389, $597 and $7,221, respectively, was capitalized as a component of property, plant and equipment.

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CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(dollars in thousands)

The Company has not recorded an asset retirement obligation as of December 31, 2010 or 2009 because such potential obligations cannot be measured since it is not possible to estimate the settlement dates.

Accumulated depreciation above includes $1,050 and $1,074 of depreciation expense for the years ended December 31, 2010 and 2009, respectively, related to the Company s capital lease assets. During the years ended December 31, 2010, 2009 and 2008, the Company recorded $51,365, $50,327 and $42,144, respectively, of depreciation expense on its property, plant and equipment.

Goodwill

Goodwill represents the excess of purchase price over fair value of the net assets acquired in the acquisition of Penreco on January 3, 2008. In accordance with ASC 350, *Intangibles Goodwill and Other* (formerly SFAS No. 142, *Goodwill and Other Intangible Assets*), goodwill and other intangible assets are not amortized, but are tested for impairment at least annually and when indicators dictate, such as adverse changes in business climate, market value of long-lived assets or a change in the structure of the Company. The Company performs its annual impairment review in the fourth quarter of each fiscal year, unless circumstances dictate more frequent assessments. No impairments were noted in 2010, 2009 or 2008.

Other Intangible Assets

Other intangible assets primarily consist of supply agreements, customer relationships, non-compete agreements and patents acquired in the acquisition of Penreco on January 3, 2008. The majority of these assets are being amortized using the discounted estimated future cash flows method over the term of the related agreements. Intangible assets associated with customer relationships of Penreco are being amortized using the discounted estimated future cash flows method based upon an assumed rate of annual customer attrition. For more information, refer to Note 5.

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.

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 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.

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

CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(dollars in thousands)

credit are generally required. The Company maintains allowances 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 customers credit quality, historical write-off experience, age of accounts receivable, average default rates provided by a third party and any known specific issues or disputes 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* (formerly SFAS No. 157, *Fair Value Measurements*), valuations to determine the impact of counterparty credit risk on the valuation of its derivative instruments.

Income Taxes

The Company, as a partnership, is not liable for income taxes on the earnings of Calumet Specialty Products Partners, L.P. and its wholly-owned subsidiaries Calumet Lubricants Co., Limited Partnership and Calumet Shreveport, LLC. However, Calumet Sales Company Incorporated (Calumet Sales Company), a wholly-owned subsidiary of the Company, is a corporation and as a result, is liable for income taxes on its earnings. Income taxes on the earnings of the Company, with the exception of Calumet Sales Company, are the responsibility of the partners, with earnings of the Company included in partners earnings.

In the event that the Company s taxable income did 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. The Company had no unrecognized tax benefits as of December 31, 2010 and 2009. The Company s income taxes generally remain subject to examination by major tax jurisdictions for a period of three years.

Net income for financial statement purposes may differ significantly from taxable income reportable to partners as a result of differences between the tax bases and financial reporting bases of assets and liabilities and the taxable income allocation requirements under the Company s partnership agreement. Individual partners have different investment bases depending upon the timing and price of acquisition of their partnership units. Furthermore, each partner s tax accounting, which is partially dependent upon the partner s tax position, differs from the accounting followed in the consolidated financial statements. Accordingly, the aggregate difference in the basis of net assets for financial and tax reporting purposes cannot be readily determined because information regarding each partner s tax attributes in the partnership is not readily available.

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 jet fuel. 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.

Derivatives

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

CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(dollars in thousands)

Other Noncurrent Assets

Other noncurrent assets consist of deferred debt issuance costs and turnaround costs. Deferred debt issuance costs were $5,812 and $7,385 as of December 31, 2010 and 2009, respectively, and are being amortized on a straight-line basis over the lives of the related debt instruments. These amounts are net of accumulated amortization of $5,246 and $3,674 at December 31, 2010 and 2009, respectively.

Turnaround costs represent capitalized costs associated with the Company s periodic major maintenance and repairs and were $9,803 and $9,125 as of December 31, 2010 and 2009, respectively. The Company capitalizes these costs and amortizes the cost on a straight-line basis over the life of the turnaround assets. These amounts are net of accumulated amortization of $11,694 and $8,035 at December 31, 2010 and 2009, respectively.

Earnings per Unit

The Company calculates earnings per unit under ASC 260-10, *Earnings per Share* (formerly EITF Issue No. 07-4, *Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships*). 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 pay 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 its partnership agreement.

Shipping and Handling Costs

The Company complies with ASC 605-45, *Revenue Recognition Principal Agent Considerations* (formerly EITF 00-10, *Accounting for Shipping and Handling Fees and Costs).* 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 $85,471, $67,967 and $84,702, respectively, for the years ended December 31, 2010, 2009, and 2008, in transportation expense in the consolidated statements of operations, the majority of which is billed to customers.

New Accounting Pronouncements

In December 2008, the FASB issued pronouncements under ASC 715-20, *Compensation-Retirement Benefits-Defined Benefit Plans (*formerly FSP FAS 132R-1, *Employers Disclosures about Postretirement Benefit Plan Assets*). ASC 715-20 replaces the requirement to disclose the percentage of the fair value of total plan assets with a requirement to disclose the fair value of each major asset category. ASC 715-20 also requires additional disclosure regarding the level of the plan assets within the fair value hierarchy according to ASC 820-10, *Fair Value Measurements and Disclosures* (formerly SFAS No. 157, *Fair Value Measurements*), and a reconciliation of activity for any plan assets being measured using unobservable inputs as defined in ASC 715-20. ASC 715-20 is effective for fiscal years ending after December 15, 2009. The adoption of ASC 715-20 did not have a material impact on the Company s financial position, results of operations, or cash flows.

In January 2010, the FASB issued ASU No. 2010-06, *Disclosures About Fair Value Measurements* (ASU 2010-06), which amends ASC No. 820, *Fair Value Measurements and Disclosures* to add new requirements for disclosures about transfers into and out of Levels 1 and 2 and separate disclosures about purchases, sales, issuances, and settlements relating to Level 3 measurements. ASU 2010-06 also clarifies existing fair value disclosures about the level of disaggregation and about inputs and valuation techniques used to measure fair value. ASU 2010-06 is effective for the first reporting period (including interim periods) beginning after December 15, 2009. The

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
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Company has adopted ASU 2010-06 standard effective January 1, 2010; however, the Company s adoption of ASU 2010-06 did not have a material effect on the Company s financial position, results of operations or cash flows.

In December 2010, the FASB issued ASU No. 2010-28, *When to Perform Step 2 of the Goodwill Impairment Test for Reporting Units with Zero or Negative Carrying Amounts* (ASU 2010-28), which amends ASC No. 830, *Intangibles Goodwill and Other* to modify Step 1 of the evaluation of goodwill impairment for reporting units with zero or negative carrying amounts to require that Step 2 of the impairment test be performed to measure the amount of any impairment loss when it is more likely than not that a goodwill impairment exits. ASU 2010-28 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2010, with early adoption not permitted. The Company does not expect the adoption of ASU 2010-28 to have a material impact on the Company s financial position, results of operations, or cash flows.

In December 2010, the FASB issued ASU No. 2010-29, *Disclosures of Supplementary Pro Forma Information for Business Combinations* (ASU 2010-29), which amends ASC No. 805, *Business Combinations,* to expand the requirements for supplemental pro forma disclosures to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. ASU 2010-29 is effective for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010, and should be applied prospectively. The Company will apply the provisions of ASU 2010-29 for all future business combinations.

3. LyondellBasell Agreements

Effective November 4, 2009, the Company entered into agreements (the LyondellBasell Agreements) with Houston Refining LP, a wholly-owned subsidiary of LyondellBasell (Houston Refining), to form a long-term specialty products affiliation. The initial term of the LyondellBasell Agreements expires on October 31, 2014 after which it is automatically extended for additional one-year terms until either party terminates with 24 months notice. Under the terms of the LyondellBasell Agreements, (i) the Company is required to purchase at least a minimum volume of 3,100 bpd of naphthenic lubricating oils produced at Houston Refining s Houston, Texas refinery, and have a right of first refusal to purchase any additional napthentic lubricating oils produced at the refinery, and (ii) Houston Refining is required to process a minimum of approximately 800 bpd of white mineral oil for the Company at Houston Refining s Houston, Texas refinery, which supplements the white mineral oil production at the Company s Karns City and Dickinson facilities. LyondellBasell has also granted the Company rights to use certain registered trademarks and tradenames, including Tufflo, Duoprime, Duotreat, Crystex, Ideal and Aquamarine.

4. Sale of Mineral Rights

In June 2008, the Company received $6,065 associated with the lease of mineral rights on the real property at the Shreveport and Princeton refineries to an unaffiliated third party which were accounted for as a sale. The Company has retained a royalty interest in any future production associated with these mineral rights. As a result of these transactions, the Company recorded a gain of $5,770 in other income (expense) in the consolidated statements of operations. Under the term loan agreement, cash proceeds resulting from this disposition of property, plant and equipment were used as a mandatory prepayment of the term loan.

5. Goodwill and Other Intangible Assets

The Company has recorded $48,335 of goodwill as a result of the acquisition of Penreco on January 3, 2008, all of which is recorded within the Company s specialty products segment.

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Other intangible assets consist of the following:

	Weighted Average Life	December 31, 2010 Gross Amount	December 31, 2010 Accumulated Amortization	December 31, 2009 Gross Amount	December 31, 2009 Accumulated Amortization
Customer relationships	20	$ 28,482	$ (10,130)	$ 28,482	$ (7,465)
Supplier agreements	4	21,519	(18,001)	21,519	(13,555)
Patents	12	1,573	(788)	1,573	(573)
Non-competition agreements	5	5,732	(2,323)	5,732	(1,615)
Distributor agreements	3	2,019	(2,019)	2,019	(1,447)
Royalty agreements	19	4,499	(897)	4,116	(693)
	12	$ 63,824	$ (34,158)	$ 63,441	$ (25,348)

Intangible assets associated with supplier agreements, non-competition agreements, patents and distributor agreements are being amortized to properly match expense with the estimated future cash flows over the term of the related agreements. Contracts with terms to allow for the potential extension of the agreement are being amortized based on the initial term only. Intangible assets associated with customer relationships of Penreco are being amortized using the discounted estimated future cash flows based upon an assumed rate of annual customer attrition. For the years ended December 31, 2010, 2009 and 2008, the Company recorded amortization expense of intangible assets of $8,810, $11,409 and $13,721, respectively. The Company estimates that amortization of intangible assets will be $6,991, $5,747, $3,114, $2,531 and $2,066 for the years ended December 31, 2011, 2012, 2013, 2014 and 2015, respectively.

6. Commitments and Contingencies

Operating Leases

The Company has various operating leases for the use of land, storage tanks, compressor stations, railcars, equipment, precious metals, operating unit catalyst used in refining processes and office facilities that extend through August 2015. Renewal options are available on certain of these leases in which the Company is the lessee. Rent expense for the years ended December 31, 2010, 2009, and 2008 was $17,104, $15,675 and $16,003, respectively.

As of December 31, 2010, 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:

Year	Operating Leases
2011	$ 12,572
2012	9,541

2013		6,814
2014		4,703
2015		1,941
Thereafter		768
Total	$	36,339

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The Company is currently purchasing all of its crude oil under evergreen contracts or on a spot basis. As of December 31, 2010, the estimated minimum purchase requirements under our crude oil and other feedstock contracts were as follows:

Year	Commitment
2011	$ 560,015
2012	157,632
2013	157,632
2014	130,835
2015	
Thereafter	
Total	$ 1,006,114

In connection with the Company s acquisition of Penreco on January 3, 2008, the Company entered into a feedstock purchase agreement with ConocoPhillips related to the LVT unit at its Lake Charles, Louisiana refinery (the LVT Feedstock Agreement). Pursuant to the LVT Feedstock Agreement, ConocoPhillips is obligated to supply a minimum quantity (the Base Volume) of feedstock for the LVT unit for a term of ten years. Based upon this minimum supply quantity, the Company is obligated to purchase approximately $64,910 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, 2010. If the Base Volume is not supplied at any point during the first five years of the ten year term, a penalty for each gallon of shortfall must be paid to the Company as liquidated damages.

Labor Matters

The Company has approximately 370 employees out of a total of approximately 650 covered by various collective bargaining agreements. These agreements have expiration dates of October 31, 2011, January 31, 2012, March 31, 2013 and April 30, 2013. The Company does not expect any work stoppages.

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 Louisiana Department of Environmental Quality (LDEQ), the U.S. Environmental Protection Agency (EPA), the Internal Revenue Service and the 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. The Company is currently pursuing an insurance claim related to property damage and business interruption at its Shreveport refinery related to the failure of an environmental operating unit in the first quarter of 2010. The outcome of this claim is uncertain at this time. Management is of the opinion that the ultimate resolution of any known claims, either individually or in the aggregate, will not have a material adverse impact on the Company s financial position, results of operations or cash flows.

Environmental

The Company operates crude oil and specialty hydrocarbon refining and terminal operations, which are subject to stringent and complex federal, state, and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations can impair the Company s operations that affect the environment in many ways, such as requiring the acquisition of permits to conduct regulated activities, restricting the manner in which the Company can release materials into the

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environment, requiring remedial activities or capital expenditures to mitigate pollution from former or current operations, and imposing substantial liabilities for pollution resulting from its operations. Certain environmental 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.

Failure to comply with environmental laws and regulations may result in the triggering of administrative, civil and criminal measures, including the assessment of monetary penalties, the imposition of remedial obligations, and the issuance of injunctions limiting or prohibiting some or all of the Company s operations. On occasion, the Company receives notices of violation, enforcement and other complaints from regulatory agencies alleging non-compliance with applicable environmental laws and regulations. For example, the LDEQ initiated enforcement actions in prior years for the following alleged violations: (i) a May 2001 notification received by the Cotton Valley refinery from the LDEQ regarding several alleged violations of various air emission regulations, as identified in the course of the Company s Leak Detection and Repair program, and also for failure to submit various reports related to the facility s air emissions; (ii) a December 2002 notification received by the Company s Cotton Valley refinery from the LDEQ regarding alleged violations for excess emissions, as identified in the LDEQ s file review of the Cotton Valley refinery; (iii) a December 2004 notification received by the Cotton Valley refinery from the LDEQ regarding alleged violations for the construction of a multi-tower pad and associated pump pads without a permit issued by the agency; and (iv) an August 2005 notification received by the Princeton refinery from the LDEQ regarding alleged violations of air emissions regulations, as identified by the LDEQ following performance of a compliance review, due to excess emissions and failures to continuously monitor and record air emissions levels. On December 23, 2010, the Company entered into a settlement agreement with the LDEQ that consolidated the terms of its settlement of the aforementioned violations with the Company s agreement to voluntarily participate in the LDEQ s Small Refinery and Single Site Refinery Initiative described below.

On December 23, 2010, we entered into a settlement agreement with the LDEQ regarding the Company s voluntary participation in the LDEQ s Small Refinery and Single Site Refinery Initiative. This state initiative is patterned after the EPA s National Petroleum Refinery Initiative, which is a coordinated, integrated compliance and enforcement strategy to address federal Clean Air Act compliance issues at the nation s largest petroleum refineries. The agreement requires the Company to make a $1,000 payment to the LDEQ, resulting in an additional $600 expense recorded during the fourth quarter of 2010, and complete beneficial environmental programs and implement emissions reduction projects at our Shreveport, Cotton Valley and Princeton refineries. We estimate implementation of these requirements will result in approximately $11,000 to $15,000 of capital expenditures and expenditures related to additional personnel and environmental studies. This agreement also fully settles the aforementioned alleged environmental and permit violations at our Shreveport, Cotton Valley and Princeton refineries and stipulates that no further civil penalties over alleged past violations will be pursued by the LDEQ. The required investments are expected to include i) nitrogen oxide and sulfur dioxide emission reductions from heaters and boilers and New Source Performance Standards applicability of, and compliance for, sulfur recovery plants and flaring devices, iii) control of incidents related to acid gas flaring, tail gas and hydrocarbon flaring, iv) electrical reliability improvements to reduce flaring, v) flare refurbishment at the Shreveport refinery, vi) enhance the Benzene Waste National Emissions Standards for Hazardous Air Pollutants programs and the Leak Detection and Repair programs at the Company s three Louisiana refineries, and vii) Title V audits and targeted audits of certain regulatory compliance programs. During these negotiations with the LDEQ, the Company voluntarily initiated projects for certain of these requirements prior to the settlement with the LDEQ, and currently anticipate completion of these projects over the next five years. These capital investment requirements will be incorporated into our annual capital expenditures budget and management does not expect any additional capital expenditures as a result of the required audits or required operational changes included in the settlement to have a material adverse effect on our financial results or operations. Management estimates that the total additional expenditures above already planned levels will be approximately $1,000 to $3,000. Before the terms of this settlement agreement are

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deemed final, the terms remain subject to public comment and the concurrence of the Louisiana Attorney General until the end of the first quarter of 2011.

Voluntary remediation of subsurface contamination is in process at each of the Company s refinery sites. The remedial projects are being overseen by the appropriate state agencies. Based on current investigative and remedial activities, the Company believes that the groundwater contamination at these refineries can be controlled or remedied without having a material adverse effect on the Company s financial condition. However, such costs are often unpredictable and, therefore, there can be no assurance that the future costs will not become material. The Company incurred approximately $541 of capital expenditures at its Cotton Valley refinery during 2010 and estimates that it will incur another $750 of capital expenditures at its Cotton Valley refinery during 2011 in connection with these activities.

The Company is indemnified by Shell Oil Company, as successor to Pennzoil-Quaker State Company and Atlas Processing Company, for specified environmental liabilities arising from the operations of the Shreveport refinery prior to the Company s acquisition of the facility. The indemnity is unlimited in amount and duration, but requires the Company to contribute up to $1,000 of the first $5,000 of indemnified costs for certain of the specified environmental liabilities.

Health, Safety and Maintenance

The Company is subject to various laws and regulations relating to occupational health and safety, including OSHA and comparable state laws. These laws and the implementing 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, training, and maintenance programs as part of its ongoing efforts to ensure compliance with applicable laws and regulations. The Company s compliance with applicable health and safety laws and regulations has required, and continues to require, substantial expenditures. The Company has implemented an internal program of inspection designed to monitor and enforce compliance with worker safety requirements as well as a quality system that meets the requirements of the ISO-9001-2008 Standard. The integrity of the Company s ISO-9001-2008 Standard certification is maintained through surveillance audits by its registrar at regular intervals designed to ensure adherence to the standards.

The Company has completed studies to assess the adequacy of its process safety management practices at its Shreveport refinery with respect to certain consensus codes and standards. The Company expects to incur between $5,000 and $8,000 of capital expenditures in total during 2011, 2012 and 2013 to address OSHA compliance issues identified in these studies. The Company expects these capital expenditures will enhance its equipment to maintain compliance with applicable consensus codes and standards. The Company believes that its operations are in substantial compliance with OSHA and similar state laws.

Beginning in February 2010, OSHA conducted an inspection of the Shreveport refinery s process safety management program under OSHA s National Emphasis Program which is targeting all U.S. refineries for review. On August 19, 2010, OSHA issued a Citation and Notification of Penalty (the Citation) to the Company as a result of this inspection which included a proposed civil penalty amount of $173. The Company contested the Citation and associated penalty amount and agreed to a final penalty amount of $119 that was paid in January 2011. The Cotton Valley refinery s process safety management program is currently undergoing inspection under OSHA s National Emphasis Program.

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Standby Letters of Credit

The Company has agreements with various financial institutions for standby letters of credit which have been issued to domestic vendors. As of December 31, 2010 and 2009, the Company had outstanding standby letters of credit of $90,725 and $46,859, respectively, under its senior secured revolving credit facility. The maximum amount of letters of credit the Company can issue is limited to its borrowing capacity under its revolving credit facility or $300,000, whichever is lower. As of December 31, 2010 and 2009, the Company had availability to issue letters of credit of $145,454 and $107,285, respectively, under its revolving credit facility. As discussed in Note 7, as of December 31, 2010 the Company also had a $50,000 letter of credit outstanding under its senior secured first lien letter of credit facility for its fuels hedging program.

7. Long-Term Debt

Long-term debt consisted of the following:

	December 31, 2010	December 31, 2009
Borrowings under senior secured first lien term loan with third-party lenders, interest at rate of three-month LIBOR plus 4.00% (4.29% and 4.27% at December 31, 2010 and December 31, 2009, respectively), interest and principal payments quarterly with remaining borrowings due January 2015, effective interest rate of 5.45% and 6.00% as of December 31, 2010 and 2009, respectively	$ 367,385	$ 371,235
Borrowings under senior secured revolving credit agreement with third-party lenders, interest at prime plus 0.50% (3.75% at December 31, 2010 and 2009), interest payments monthly, borrowings due January 2013	10,832	39,900
Capital lease obligations, interest at 8.25%, interest and principal payments quarterly through January 2012	1,781	2,938
Less unamortized discount on new senior secured first lien term loan with third-party lenders	(10,723)	(13,015)
Total long-term debt	369,275	401,058
Less current portion of long-term debt	4,844	5,009
	$ 364,431	$ 396,049

The Company s $435,000 senior secured first lien term loan facility includes a $385,000 term loan and a $50,000 prefunded letter of credit facility to support crack spread hedging, which bears interest at 4.0%. In the event the counterparty holding this letter of credit has exposure to the Company in excess of $100,000, the Company would be required to post additional credit support with the counterparty to enter into additional crack spread hedges. The term loan bears interest at a rate equal to (i) with respect to a LIBOR Loan, the LIBOR Rate plus 400 basis points (the Applicable Rate defined in the term loan credit agreement) and (ii) with respect to a Base Rate Loan, the Base Rate plus 300 basis points (as defined in the term loan credit agreement).

Lenders under the term loan facility have a first priority lien on the Company s fixed assets and a second priority lien on its cash, accounts receivable, inventory and other personal property. The term loan facility requires quarterly principal payments of $963 until maturity on September 30, 2014, with the remaining balance due at maturity on January 3, 2015.

The Company s senior secured revolving credit facility has a maximum availability of up to $375,000, subject to borrowing base limitations. The revolving credit facility, which is the Company s primary source of liquidity for cash needs in excess of cash generated from operations, currently bears interest at a rate equal to prime plus a basis points margin or LIBOR plus a basis points margin, at the Company s option. As of December 31, 2010, the margin

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is 50 basis points for prime and 200 basis points for LIBOR; however, the margin fluctuates based on quarterly measurement of the Company s Consolidated Leverage Ratio (as defined in the credit agreement). The senior secured revolving credit facility matures on January 3, 2013.

The borrowing capacity at December 31, 2010 under the revolving credit facility was $247,012, with $145,454 available for additional borrowings based on collateral and specified availability limitations. Lenders under the revolving credit facility have a first priority lien on the Company s cash, accounts receivable, inventory and other personal property and a second priority lien on the Company s fixed assets.

Compliance with the financial covenants pursuant to the Company s credit agreements is tested quarterly based upon performance over the most recent four fiscal quarters, and as of December 31, 2010, the Company was in compliance with all financial covenants under its credit agreements. Even though its liquidity and leverage improved during 2010, the Company is continuing to take steps to ensure that it meets the requirements of its credit agreements and currently forecasts that it will be in compliance at future measurement dates, although assurances cannot be made regarding the Company s future compliance with these covenants.

Failure to achieve the Company s anticipated results may result in a breach of certain of the financial covenants contained in its credit agreements. If this occurs, the Company will enter into discussions with its lenders to either modify the terms of the existing credit facilities or obtain waivers of non-compliance with such covenants. There can be no assurances of the timing of the receipt of any such modification or waiver, the term or costs associated therewith or our ultimate ability to obtain the relief sought. The Company s failure to obtain a waiver of non-compliance with certain of the financial covenants or otherwise amend the credit facilities would constitute an event of default under its credit facilities and would permit the lenders to pursue remedies. These remedies could include acceleration of maturity under the credit facilities and limitations or the elimination of the Company s ability to make distributions to its unitholders. If the Company s lenders accelerate maturity under its credit facilities, a significant portion of its indebtedness may become due and payable immediately. The Company might not have, or be able to obtain, sufficient funds to make these accelerated payments. If the Company is unable to make these accelerated payments, its lenders could seek to foreclose on its assets.

As of December 31, 2010, maturities of the Company s long-term debt are as follows:

Year	**Maturity**
2011	$ 4,844
2012	4,401
2013	14,918
2014	2,888
2015	352,947
Thereafter	
Total	$ 379,998

In 2007, the Company entered into a capital lease for catalyst used in refining processes which will expire in 2012. In 2009, the Company entered into a capital lease for catalyst which will expire in 2013 to replace a portion of the catalyst under an existing capital lease that was disposed. Assets recorded under these capital lease obligations are included in property, plant and equipment and consist of $4,201 and $4,198 as of December 31, 2010 and 2009, respectively.

As of December 31, 2010 and 2009, the Company had recorded $2,171 and $1,120, respectively, in accumulated amortization for these capital lease assets.

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As of December 31, 2010, the Company had estimated minimum commitments for the payment of total rentals under capital leases as follows:

Year	Capital Leases
2011	$ 1,069
2012	571
2013	240
Total minimum lease payments	1,880
Less amount representing interest	99
Capital lease obligations	1,781
Less obligations due within one year	994
Long-term capital lease obligations	$ 787

8. Derivatives

The Company utilizes derivative instruments to minimize its price risk and volatility of cash flows associated with the purchase of crude oil and natural gas, the sale of fuel products and interest payments. The Company employs various hedging strategies, which are further discussed below. The Company does not hold or issue derivative instruments for trading purposes.

The Company recognizes all derivative instruments at their fair values (see Note 9) as either assets or liabilities on 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

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financial reporting purposes. The Company recorded the following derivative assets and liabilities at their fair values as of December 31, 2010 and December 31, 2009:

	Derivative Assets		Derivative Liabilities	
	December 31, 2010	December 31, 2009	December 31, 2010	December 31, 2009
Derivative instruments designated as hedges:				
Fuel products segment:				
Crude oil swaps	$	$ 134,587	$ 134,916	$
Gasoline swaps		(6,147)	(14,149)	
Diesel swaps		(67,731)	(53,744)	
Jet fuel swaps		(26,926)	(96,556)	
Specialty products segment:				
Crude oil collars				
Crude oil swaps				
Natural gas swaps				
Interest rate swaps:			(2,681)	(2,752)
Total derivative instruments designated as hedges		33,783	(32,214)	(2,752)
Derivative instruments not designated as hedges:				
Fuel products segment:				
Crude oil swaps (1)		13,062		
Gasoline swaps (1)		(16,165)		
Diesel swaps				
Jet fuel crack spread collars (2)		375	20	
Specialty products segment:				
Crude oil collars (3)		(151)		
Crude oil swaps (3)			662	
Natural gas swaps (3)				
Interest rate swaps: (4)			(1,282)	(2,014)
Total derivative instruments not designated as hedges		(2,879)	(600)	(2,014)
Total derivative instruments	$	$ 30,904	$ (32,814)	$ (4,766)

(1) The Company entered into derivative instruments, which do not qualify for hedge accounting, to economically lock in a gain on a portion of the Company s gasoline and crude oil swap contracts that are designated as hedges.

(2) The Company entered into jet fuel crack spread collars, which do not qualify for hedge accounting, to economically hedge its exposure to changes in the jet fuel crack spread.

(3) The Company enters into combinations of crude oil options and swaps and natural gas swaps to economically hedge its exposures to price risk related to these commodities in its specialty products segment. The Company has not designated these derivative instruments as hedges.

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(4) The Company refinanced its long-term debt in January 2008 and, as a result, the interest rate swap that was designated as a hedge of the interest payments under the previous debt agreement no longer qualified for hedge accounting. To offset the effect of this interest rate swap, the Company entered into another interest rate swap. These two derivative instruments are netted on this line item and the Company is settling this net position over the term of the derivative instruments.

To the extent a derivative instrument 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. The Company accounts for certain derivatives hedging purchases of crude oil and natural gas, sales of gasoline, diesel and jet fuel and the payment of interest as cash flow hedges. The derivatives 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 derivatives hedging payments of interest are recorded in interest expense in the consolidated statements of operations upon payment of interest. The Company assesses, both at inception of the hedge and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items.

For derivative instruments not designated as cash flow hedges and the portion of any cash flow hedge that is determined to be ineffective, the change in fair value of the asset or liability for the period is recorded to unrealized gain (loss) on derivative instruments in the consolidated statements of operations. Upon the settlement of a derivative not designated as a cash flow hedge, the gain or loss at settlement is recorded to realized gain (loss) on derivative instruments in the consolidated statements of operations.

The Company recorded the following amounts in its consolidated balance sheets, consolidated statements of operations and its consolidated statements of partners capital as of, and for the years ended, December 31, 2010 and 2009 related to its derivative instruments that were designated as cash flow hedges:

	Amount of Gain (Loss) Recognized in Accumulated Other Comprehensive Income on Derivatives (Effective Portion)			Amount of (Gain) Loss Reclassified from Accumulated Other Comprehensive Income into Net Income (Effective Portion)			Amount of Gain (Loss) Recognized in I Income on Derivatives (Ineffective Portion)	
	December 31,			Year Ended December 31,			Year Ended December 31,	
of Derivative	2010	2009	Location of (Gain) Loss	2010	2009	Location of Gain (Loss)	2010	20
products ent:								
oil swaps	$ 73,661	$ 231,177	Cost of sales	$ (81,647)	$ 55,974	Unrealized/Realized	$ (10,077)	$ 26,
ine swaps	(1,329)	(141,347)	Sales	23,973	(19,859)	Unrealized/Realized	(4,034)	1,
l swaps	(31,839)	(89,763)	Sales	43,685	(54,729)	Unrealized/Realized	(2,430)	(17,

el swaps	(66,693)	(26,926)	Sales			Unrealized/Realized	(2,936)	
alty products								
ent:								
e oil collars			Cost of sales			Unrealized/Realized		
e oil swaps			Cost of sales			Unrealized/Realized		
al gas swaps		(101)	Cost of sales		307	Unrealized/Realized		
st rate swaps:	(2,815)	(2,411)	Interest expense	2,885	3,239	Unrealized/Realized		
	$ (29,015)	$ (29,371)		$ (11,104)	$ (15,068)		$ (19,477)	$ 9,

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CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(dollars in thousands)

The Company recorded the following gains (losses) in its consolidated statements of operations for the years ended December 31, 2010 and 2009 related to its derivative instruments not designated as cash flow hedges:

Type of Derivative	Amount of Gain (Loss) Recognized in Realized Gain (Loss) on Derivatives Year Ended December 31, 2010	2009	Amount of Gain (Loss) Recognized in Unrealized Gain (Loss) on Derivatives Year Ended December 31, 2010	2009
Fuel products segment:				
Crude oil swaps	$ (9,508)	$ 12,362	$ 10,907	$ (38,371)
Gasoline swaps	14,318	10,107	(14,864)	36,763
Diesel swaps	(1,301)	(6,655)	1,301	6,655
Jet fuel swaps				
Jet fuel collars			(355)	(371)
Specialty products segment:				
Crude oil collars	(3,698)	(9,148)	153	12,194
Crude oil swaps	(1,086)		661	
Natural gas swaps	(515)	(1,578)		1,222
Interest rate swaps:	(814)	(824)	731	173
Total	$ (2,604)	$ 4,264	$ (1,466)	$ 18,265

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. To manage credit risk, the Company selects and periodically reviews counterparties based on credit ratings. The Company executes all of its derivative instruments with large financial institutions that have ratings of at least A2 and A by Moody s and S&P, respectively. In the event of default, the Company would potentially be subject to losses on derivative instruments with mark to market gains. The Company requires collateral from its counterparties when the fair value of the derivatives exceeds agreed upon thresholds in its contracts with these counterparties. The Company s contracts with these counterparties allow for netting of derivative instrument positions 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 not netted against derivative assets or liabilities. As of December 31, 2010, the Company had provided its counterparties with no cash collateral or letters of credit above the $50,000 prefunded letter of credit provided to one counterparty to support crack spread hedging. For financial reporting purposes, the Company does not offset the collateral provided to a counterparty against the fair value of its obligation to that counterparty. Any outstanding collateral is released to the Company upon settlement of the related derivative instrument liability.

Certain of the Company s outstanding derivative instruments are subject to credit support agreements with the applicable counterparties which contain provisions setting certain credit thresholds above which the Company may be required to post agreed-upon collateral, such as cash or letters of credit, with the counterparty to the extent that the Company s mark-to-market net liability, if any, on all outstanding derivatives exceeds the credit threshold amount per such credit support agreement. In certain cases, the Company s credit threshold is dependent upon the Company s maintenance of certain corporate credit ratings with Moody s and S&P. In the event that the Company s corporate credit rating was lowered below its current level by either Moody s or S&P, such counterparties would have the right to reduce the applicable threshold to zero and demand full collateralization of the Company s net liability position on outstanding derivative instruments. As of December 31, 2010, there is a liability of $388

CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(dollars in thousands)

associated with the Company s outstanding derivative instruments subject to such requirements. In addition, the majority of the credit support agreements covering the Company s outstanding derivative instruments also contain a general provision stating that if the Company experiences a material adverse change in its business, in the reasonable discretion of the counterparty, the Company s credit threshold could be lowered by such counterparty. The Company does not expect that it will experience a material adverse change in its business. The effective portion of the hedges classified in accumulated other comprehensive loss is $22,765 as of December 31, 2010 and, absent a change in the fair market value of the underlying transactions, will be reclassified to earnings by December 31, 2012 with balances being recognized as follows:

Year		**Accumulated Other Comprehensive Loss**
2011	$	(5,736)
2012		(17,029)
Total	$	(22,765)

Crude Oil Swap and Collar Contracts Specialty Products Segment

The Company is exposed to fluctuations in the price of crude oil, its principal raw material. The Company utilizes combinations of options and swaps to manage crude oil price risk and volatility of cash flows in its specialty products segment. These derivatives may be designated as cash flow hedges of the future purchase of crude oil if they meet the hedge criteria. The Company s general policy is to enter into crude oil derivative contracts that mitigate the Company s exposure to price risk associated with crude oil purchases related to specialty products production (for up to 70% of expected purchases). As of December 31, 2010, the Company has hedged less than 5% of its expected specialty products crude purchases for the three months ended March 31, 2011. While the Company s policy generally requires that these positions be short term in nature and expire within three to nine months from execution, the Company may execute derivative contracts for up to two years forward, if a change in the risks supports lengthening the Company s position. As of December 31, 2010, the Company had the following crude oil derivatives related to crude oil purchases and forecasted changes in crude oil inventory levels in its specialty products segment, none of which are designated as hedges.

Crude Oil Swap Contracts by Expiration Dates	**Barrels Purchased**	**BPD**	**Average Swap ($/Bbl)**
February 2011	33,600	1,200	$ 83.10
March 2011	37,200	1,200	83.55
Totals	70,800		

Average price	$ 83.34

As of December 31, 2009, the Company had the following crude oil derivatives related to crude oil purchases in its specialty products segment, none of which are designated as hedges.

Crude Oil Put/Swap/Call Contracts by Expiration Dates	**Barrels**	**BPD**	**Average Bought Put ($/Bbl)**	**Average Swap ($/Bbl)**	**Average Sold Call ($/Bbl)**
January 2010	186,000	6,000	$ 68.32	$ 80.43	$ 90.43
Totals	186,000				
Average price			$ 68.32	$ 80.43	$ 90.43

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CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(dollars in thousands)

Crude Oil Swap Contracts Fuel Products Segment

The Company is exposed to fluctuations in the price of crude oil, its principal raw material. The Company utilizes swap contracts to manage crude oil price risk and volatility of cash flows in its fuel products segment. The Company s policy is generally to enter into crude oil swap contracts for a period no greater than five years forward and for no more than 75% of crude oil purchases used in fuels production. At December 31, 2010, the Company had the following derivatives related to crude oil purchases in its fuel products segment, all of which are designated as hedges.

Crude Oil Swap Contracts by Expiration Dates	**Barrels Purchased**	**BPD**	**Average Swap ($/Bbl)**
First Quarter 2011	1,215,000	13,500	$ 75.32
Second Quarter 2011	1,729,000	19,000	76.62
Third Quarter 2011	1,610,000	17,500	77.38
Fourth Quarter 2011	1,334,000	14,500	77.71
Calendar Year 2012	5,535,000	15,123	86.30
Totals	11,423,000		
Average price			$ 81.41

At December 31, 2009, the Company had the following derivatives related to crude oil purchases in its fuel products segment, all of which are designated as hedges.

Crude Oil Swap Contracts by Expiration Dates	**Barrels Purchased**	**BPD**	**Average Swap ($/Bbl)**
First Quarter 2010	1,800,000	20,000	$ 67.29
Second Quarter 2010	1,820,000	20,000	67.29
Third Quarter 2010	1,840,000	20,000	67.29
Fourth Quarter 2010	1,840,000	20,000	67.29
Calendar Year 2011	5,614,000	15,381	76.54
Totals	12,914,000		
Average price			$ 71.31

At December 31, 2009, the Company had the following derivatives related to crude oil sales in its fuel products segment, none of which are designated as hedges.

Average

Crude Oil Swap Contracts by Expiration Dates	Barrels Sold	BPD	Swap ($/Bbl)
First Quarter 2010	135,000	1,500	$ 58.25
Second Quarter 2010	136,500	1,500	58.25
Third Quarter 2010	138,000	1,500	58.25
Fourth Quarter 2010	138,000	1,500	58.25
Totals	547,500		
Average price			$ 58.25

CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(dollars in thousands)

Fuel Products Swap Contracts

The Company is exposed to fluctuations in the prices of gasoline, diesel, and jet fuel. The Company utilizes swap contracts to manage diesel, gasoline and jet fuel price risk and volatility of cash flows in its fuel products segment. The Company s policy is generally to enter into diesel, jet fuel and gasoline swap contracts for a period no longer than five years forward and for no more than 75% of forecasted fuel sales.

Diesel Swap Contracts

At December 31, 2010, the Company had the following derivatives related to diesel and jet fuel sales in its fuel products segment, all of which are designated as hedges.

Diesel Swap Contracts by Expiration Dates	**Barrels Sold**	**BPD**	**Average Swap ($/Bbl)**
First Quarter 2011	630,000	7,000	$ 89.57
Second Quarter 2011	637,000	7,000	89.57
Third Quarter 2011	552,000	6,000	91.74
Fourth Quarter 2011	552,000	6,000	91.74
Calendar Year 2012	1,560,000	4,262	99.27
Totals	3,931,000		
Average price			$ 94.03

At December 31, 2009, the Company had the following derivatives related to diesel and jet fuel sales in its fuel products segment, all of which are designated as hedges.

Diesel Swap Contracts by Expiration Dates	**Barrels Sold**	**BPD**	**Average Swap ($/Bbl)**
First Quarter 2010	1,170,000	13,000	$ 80.41
Second Quarter 2010	1,183,000	13,000	80.41
Third Quarter 2010	1,196,000	13,000	80.41
Fourth Quarter 2010	1,196,000	13,000	80.41
Calendar Year 2011	2,371,000	6,496	90.58
Totals	7,116,000		
Average price			$ 83.80

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CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(dollars in thousands)

Jet Fuel Swap Contracts

At December 31, 2010, the Company had the following derivatives related to diesel and jet fuel sales in its fuel products segment, all of which are designated as hedges.

Jet Fuel Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
First Quarter 2011	405,000	4,500	$ 86.12
Second Quarter 2011	819,000	9,000	89.58
Third Quarter 2011	920,000	10,000	89.86
Fourth Quarter 2011	644,000	7,000	89.21
Calendar Year 2012	3,838,500	10,488	99.78
Totals	6,626,500		
Average price			$ 95.28

At December 31, 2009, the Company had the following derivatives related to diesel and jet fuel sales in its fuel products segment, all of which are designated as hedges.

Jet Fuel Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
Calendar Year 2011	2,514,000	6,888	$ 88.51
Totals	2,514,000		
Average price			$ 88.51

Gasoline Swap Contracts

At December 31, 2010, the Company had the following derivatives related to gasoline sales in its fuel products segment, all of which are designated as hedges.

Gasoline Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
First Quarter 2011	180,000	2,000	$ 81.84

Second Quarter 2011	273,000	3,000	82.66
Third Quarter 2011	138,000	1,500	85.50
Fourth Quarter 2011	138,000	1,500	85.50
Calendar Year 2012	136,500	373	89.04
Totals	865,500		
Average price			$ 84.40

At December 31, 2009, the Company had the following derivatives related to gasoline sales in its fuel products segment, all of which are designated as hedges.

CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(dollars in thousands)

Gasoline Swap Contracts by Expiration Dates	Barrels Sold	BPD	Average Swap ($/Bbl)
First Quarter 2010	630,000	7,000	$ 75.28
Second Quarter 2010	637,000	7,000	75.28
Third Quarter 2010	644,000	7,000	75.28
Fourth Quarter 2010	644,000	7,000	75.28
Calendar Year 2011	729,000	1,997	83.53
Totals	3,284,000		
Average price			$ 77.11

At December 31, 2009, 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 2010	135,000	1,500	$ 58.42
Second Quarter 2010	136,500	1,500	58.42
Third Quarter 2010	138,000	1,500	58.42
Fourth Quarter 2010	138,000	1,500	58.42
Totals	547,500		
Average price			$ 58.42

Jet Fuel Put Spread Contracts

At December 31, 2010, the Company had the following jet fuel put options related to jet fuel crack spreads in its fuel products segment, none of which are designated as hedges.

Jet Fuel Put Option Crack Spread Contracts by Expiration Dates	Barrels	BPD	Average Sold Put ($/Bbl)	Average Bought Put ($/Bbl)
First Quarter 2011	630,000	7,000	$ 4.00	$ 6.00
Fourth Quarter 2011	184,000	2,000	4.75	7.00

Totals	814,000			
Average price			$ 4.17	$ 6.23

At December 31, 2009, the Company had the following jet fuel put options related to jet fuel crack spreads in its fuel products segment, none of which are designated as hedges.

Jet Fuel Put Option Crack Spread Contracts by Expiration Dates	**Barrels**	**BPD**	**Average Sold Put ($/Bbl)**	**Average Bought Put ($/Bbl)**
First Quarter 2011	630,000	7,000	$ 4.00	$ 6.00
Fourth Quarter 2011	184,000	2,000	4.75	7.00
Totals	814,000			
Average price			$ 4.17	$ 6.23

CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(dollars in thousands)

Natural Gas Swap Contracts

Natural gas purchases comprise a significant component of the Company s cost of sales, therefore, changes in the price of natural gas also significantly affect its profitability and cash flows. The Company utilizes swap contracts to manage natural gas price risk and volatility of cash flows. The Company s policy is generally to enter into natural gas derivative contracts to hedge approximately 50% or more of its upcoming fall and winter months anticipated natural gas requirement for a period no greater than three years forward. At December 31, 2010 and 2009, the Company did not have any derivatives outstanding related to natural gas purchases.

Interest Rate Swap Contracts

The Company s profitability and cash flows are affected by changes in interest rates, specifically LIBOR and prime rates. The primary purpose of the Company s interest rate risk management activities is to hedge its exposure to changes in interest rates. The Company s policy is generally to enter into interest rate swap agreements to hedge up to 75% of its interest rate risk under its term loan agreement.

During 2010, the Company entered into forward swap contracts to manage interest rate risk related to a portion of its current variable rate senior secured first lien term loan. The Company hedged the future interest payments related to $100,000 of the total outstanding term loan indebtedness for the period from February 15, 2011 to February 15, 2012 pursuant to these forward swap contracts. These swap contracts are designated as cash flow hedges of the future payments of interest with three-month LIBOR fixed at an average rate during the hedge period of 2.03%.

In 2009, the Company hedged the future interest payments related to $200,000 of the total outstanding term loan indebtedness for the period from February 15, 2010 to February 15, 2011. This swap contract is designated as a cash flow hedge of the future payment of interest with three-month LIBOR fixed at an average rate during the hedge period of 0.94%.

In 2008, the Company entered into a forward swap contract to manage interest rate risk related to a portion of its current variable rate senior secured first lien term loan which closed January 3, 2008. The Company hedged the future interest payments related to $150,000 and $50,000 of the total outstanding term loan indebtedness in 2009 and 2010, respectively, pursuant to this forward swap contract. This swap contract is designated as a cash flow hedge of the future payment of interest with three-month LIBOR fixed at 3.09% and 3.66% per annum in 2009 and 2010, respectively.

In 2006, the Company entered into a forward swap contract to manage interest rate risk related to a portion of its then existing variable rate senior secured first lien term loan. Due to the repayment of $19,000 of the outstanding balance of the Company s then existing term loan facility in August 2007 and subsequent refinancing of the remaining term loan balance, this swap contract was not designated as a cash flow hedge of the future payment of interest. The entire change in the fair value of this interest rate swap is recorded to unrealized gain (loss) on derivative instruments in the consolidated statements of operations. In the first quarter of 2008, the Company fixed its unrealized loss on this interest rate swap derivative instrument by entering into an offsetting interest rate swap expiring December 2012 which is not designated as a cash flow hedge.

9. Fair Value of Financial Instruments

The Company s financial instruments which require fair value disclosure consist primarily of cash and cash equivalents, accounts receivable, financial derivatives, accounts payable and indebtedness. The carrying values of cash and cash equivalents, accounts receivable and accounts payable are considered to be representative of their respective fair values, due to the short maturity of these instruments. Derivative instruments are reported in the accompanying consolidated financial statements at fair value. The fair value of the Company s term loan was $355,445 and $328,543 at December 31, 2010 and December 31, 2009, respectively. The carrying values of

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CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(dollars in thousands)

borrowings under the Company s senior secured revolving credit facility were $10,832 and $39,900 at December 31, 2010 and December 31, 2009, respectively, and approximate their fair values. In addition, based upon fees charged for similar agreements, the face values of outstanding standby letters of credit approximated their fair values at December 31, 2010 and December 31, 2009.

10. Fair Value Measurements

The Company uses a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value. These tiers include: Level 1, defined as observable inputs such as quoted prices in active markets; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as 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.

As of December 31, 2010, the Company held certain assets and liabilities that are required to be measured at fair value on a recurring basis. These included the Company s derivative instruments related to crude oil, gasoline, diesel, jet fuel and interest rates, and investments associated with the Company s non-contributory defined benefit plan (Pension Plan).

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 A2 and A by Moody s and S&P, respectively. To estimate the fair values of the Company s derivative instruments, the entity uses the market approach. Under this approach, the fair values of the Company s derivative instruments for crude oil, gasoline, diesel, jet fuel and interest rates are determined primarily based on inputs that are readily available in public markets or can be derived from information available in publicly quoted markets. Generally, the Company obtains this data through surveying its counterparties and performing various analytical tests to validate the data. The Company determines the fair value of its crude oil option contracts utilizing a standard option pricing model based on inputs that can be derived from information available in publicly quoted markets, or are quoted by counterparties to these contracts. In situations where the Company obtains inputs via quotes from its counterparties, it verifies the reasonableness of these quotes via similar quotes from another counterparty as of each date for which financial statements are prepared. The Company also includes an adjustment for non-performance risk in the recognized measure of fair value of all of the Company s derivative instruments. The adjustment reflects the full credit default spread (CDS) applied to a net exposure by counterparty. When the Company is in a net asset position, it uses its counterparty s CDS, or a peer group s estimated CDS when a CDS for the counterparty is not available. The Company uses its own peer group s estimated CDS when it is in a net liability position. As a result of applying the applicable CDS, at December 31, 2010, the Company s liability was reduced by approximately $687. Based on the use of various unobservable inputs, principally non-performance risk and unobservable inputs in forward years for gasoline, jet fuel and diesel, the Company has categorized these derivative instruments as Level 3. The Company has consistently applied these valuation techniques in all periods presented and believes it has obtained the most accurate information available for the types of derivative instruments it holds.

The Company s investments associated with its Pension Plan consist of mutual funds that are publicly traded and for which market prices are readily available, thus these investments are categorized as Level 1.

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CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(dollars in thousands)

The Company s assets and liabilities measured at fair value at December 31, 2010 were as follows:

	Fair Value Measurements			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 37	$	$	$ 37
Crude oil swaps			135,578	135,578
Gasoline swaps				
Diesel swaps				
Jet fuel swaps				
Crude oil options				
Jet fuel options			20	20
Pension plan investments	16,039			16,039
Total assets at fair value	$ 16,076	$	$ 135,598	$ 151,674
Liabilities:				
Crude oil swaps	$	$	$	$
Gasoline swaps			(14,149)	(14,149)
Diesel swaps			(53,744)	(53,744)
Jet fuel swaps			(96,556)	(96,556)
Crude oil options				
Jet fuel options				
Interest rate swaps			(3,963)	(3,963)
Pension plan investments				
Total liabilities at fair value	$	$	$ (168,412)	$ (168,412)

CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(dollars in thousands)

The Company s assets and liabilities measured at fair value at December 31, 2009 were as follows:

	Fair Value Measurements			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 49	$	$	$ 49
Crude oil swaps			147,649	147,649
Gasoline swaps				
Diesel swaps				
Jet fuel swaps				
Crude oil options				
Jet fuel options			375	375
Pension plan investments	13,730			13,730
Total assets at fair value	$ 13,779	$	$ 148,024	$ 161,803
Liabilities:				
Crude oil swaps	$	$	$	$
Gasoline swaps			(22,312)	(22,312)
Diesel swaps			(67,731)	(67,731)
Jet fuel swaps			(26,926)	(26,926)
Crude oil options			(151)	(151)
Jet fuel options				
Interest rate swaps			(4,766)	(4,766)
Pension plan investments				
Total liabilities at fair value	$	$	$ (121,886)	$ (121,886)

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, 2010 and 2009:

	Derivative Instruments, Net Year Ended December 31,	
	2010	2009
Fair value at January 1, 2010	$ 26,138	$ 55,372
Realized losses (gains)	7,704	(8,342)
Unrealized (losses) gains	(15,843)	23,736
Change in fair value of cash flow hedges	(29,015)	(29,371)
Purchases, issuances and settlements	(21,798)	(15,257)

Transfers in (out) of Level 3		
Fair value at December 31, 2010	$ (32,814)	$ 26,138
Total (losses) gains included in net income attributable to changes in unrealized gains (losses) relating to financial assets and liabilities held as of December 31, 2010	$ (15,843)	$ 23,736

All settlements from derivative instruments that are deemed effective and were designated as cash flow hedges are included in sales for gasoline, diesel and jet fuel derivatives, cost of sales for crude oil and natural gas

CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(dollars in thousands)

derivatives, and interest expense for interest rate derivatives in the consolidated financial statements of operations in the period that the hedged cash flow occurs. Any ineffectiveness associated with these derivative instruments are recorded in earnings immediately in unrealized gain (loss) on derivative instruments in the consolidated statements of operations. All settlements from derivative instruments not designated as cash flow hedges are recorded in realized gain (loss) on derivative instruments in the consolidated statements of operations. See Note 8 for further information on derivative instruments.

11. Partners Capital

On December 14, 2009, the Company completed a public equity offering of its common units in which it sold 3,000,000 common units to the underwriters of the offering at a price to the public of $18.00 per common unit. This issuance was made pursuant to the Company s Registration Statement on Form S-3 (File No. 333-145657) declared effective by the Securities and Exchange Commission on November 9, 2007. In addition, on January 7, 2010 we sold an additional 47,778 common units to the underwriters at a price to the public of $18.00 per common unit pursuant to the underwriters over-allotment option. The proceeds received by the Company (net of underwriting discounts, commissions and expenses but before its general partner s capital contribution) from this offering were $51,225 and used to repay borrowings under its revolving credit facility. Underwriting discounts totaled $2,295. The Company s general partner contributed $1,102 to retain its 2% general partner interest.

Of the 22,213,778 common units outstanding at December 31, 2010, 16,019,463 common units were held by the public, with the remaining 6,194,315 common units held by the Company s affiliates. At the time of conversion, all of the 13,066,000 subordinated units were held by affiliates of the Company. Upon expiration of the subordination period on February 16, 2011, each outstanding subordinated unit automatically converted into one common unit and participates pro rata with the other common units in distributions of available cash as defined in the Company s partnership agreement.

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 662/3% 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.

CALUMET SPECIALTY PRODUCTS PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
(dollars in thousands)

The Company s general partner is entitled to incentive distributions if the amount it distribute to unitholders with respect to any quarter exceeds specified target levels shown below:

	Total Quarterly Distribution	Marginal Percentage Interest in Distributions	
	Target Amount	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 credit agreements. The credit agreements permit the Company to make distributions to its unitholders as long as it is not in default and would not be in default following the distribution. Under the credit facilities, the Company is obligated to comply with certain financial covenants requiring it to maintain a Consolidated Leverage Ratio of no more than 3.75 to 1 and a Consolidated Interest Coverage Ratio of no less than 2.75 to 1 (as of the end of each fiscal quarter and after giving effect to a proposed distribution or other restricted payments as defined in the credit agreement) and available liquidity of at least $35.0 million (after giving effect to a proposed distribution or other restricted payments as defined in the credit agreements).

The Company s distribution policy is as defined in its partnership agreement. For the years ended December 31, 2010, 2009 and 2008, the Company made distributions of $65,739, $59,258 and $66,140, respectively, to its partners.

12. Unit-Based Compensation

The Company s general partner originally adopted a Long-Term Incentive Plan (the Plan) on January 24, 2006, which was amended and restated effective January 22, 2009, for its employees, consultants and directors and its affiliates who perform services for the Company. The Plan 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 783,960 common units may be delivered pursuant to awards under the Plan. Units withheld to satisfy the Company s general partner s tax withholding obligations are available for delivery pursuant to other awards. The Plan is administered by the compensation committee of the Company s general partner s board of directors.

Non-employee directors of our general partner have been granted phantom units under the terms of the Plan as part of their director compensation package related to fiscal years 2008, 2009 and 2010. 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, the recipients have DERs on these phantom units from the date of grant.

For the year ended December 31, 2010, named executive officers and certain employees were awarded phantom units under the terms of the Plan, as part of the Company s achievement of specified levels of financial performance in fiscal year 2010. These phantom units are subject to time-vesting requirements whereby 25% of the units vest in the first quarter of 2011, 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 will have DERs beginning in the first quarter of 2011.

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On January 22, 2009, the board of directors of the Company s general partner approved discretionary contributions to participant accounts for certain directors and employees in the form of phantom units under the Calumet Specialty Products Partners, L.P. Executive Deferred Compensation Plan. The phantom unit awards vest in one-quarter increments over a four year service period, subject to early vesting on a change in control, upon termination without cause, or due to death, disability or normal retirement. These phantom units also carry DERs 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 selling, general and administrative expense in the consolidated statements of operations using the straight-line method over the four year vesting period, as it expects these units to fully vest.

A summary of the Company s nonvested phantom units as of December 31, 2010, and the changes during the years ended December 31, 2010, 2009 and 2008, are presented below:

	Number of Phantom Units	Weighted-Average Grant Date Fair Value	
Nonvested at January 1, 2008	8,508	$	35.56
Granted	30,192		7.79
Vested	(10,992)		16.38
Forfeited			
Nonvested at December 31, 2008	27,708	$	12.91
Granted	47,121		13.29
Vested	(17,336)		15.56
Forfeited			
Nonvested at December 31, 2009	57,493	$	12.42
Granted	138,490		20.11
Vested	(90,491)		18.05
Forfeited			
Nonvested at December 31, 2010	105,492	$	17.68

For the years ended December 31, 2010, 2009 and 2008, compensation expense of $784, $367 and $179, respectively, was recognized in the consolidated statements of operations related to vested phantom unit grants. As of December 31, 2010 and 2009, there was a total of $1,865 and $714, respectively of unrecognized compensation costs related to nonvested phantom unit grants. These costs are expected to be recognized over a weighted-average period of three years. The total fair value of phantom units vested during the years ended December 31, 2010 and 2009, was $1,927 and $318, respectively.

13. Employee Benefit Plans

The Company has a defined contribution plan administered by its general partner. All full-time employees who have completed at least one hour of service are eligible to participate in the plan. Participants are allowed to contribute 0% to 100% of their pre-tax earnings to the plan, subject to government imposed limitations. The Company matches 100% of each 1% contribution by the participant up to 4% and 50% of each additional 1% contribution up to 6% for a maximum contribution by the Company of 5% per participant. The Company s matching contribution was $1,948, $2,040, and $1,782 for the years ended December 31, 2010, 2009 and 2008, respectively. The plan also includes a profit-sharing component. Contributions under the profit-sharing component

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are determined by the board of directors of the Company s general partner and are discretionary. The Company s profit sharing contribution was $1,331, $1,308, and $1,123 for the years ended December 31, 2010, 2009 and 2008, respectively.

The Company has a noncontributory defined benefit plan (Pension Plan) for both those salaried employees as well as those employees represented by either the United Steelworkers (USW) or the International Union of Operating Engineers (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. The Company also has a contributory defined benefit postretirement medical plan for both 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, as well as a non-contributory disability plan for those salaried employees who were formerly employees of Penreco (collectively, Other Plans). The pension benefits are based primarily on years of service for USW and IUOE represented employees and both years of service and the employee s final 60 months average compensation for salaried employees. The funding policy is consistent with funding requirements of applicable laws and regulations. The assets of these plans consist of corporate equity securities, municipal and government bonds, and cash equivalents. In 2009, the Company amended the Pension Plan. The amendments removed employees from accumulating additional benefits subsequent to December 31, 2009. All information presented below has been adjusted for this curtailment.

The components of net periodic pension and other post retirement benefits cost for the years ended December 31, 2010 and 2009 were as follows:

	Year Ended December 31,			
	2010		2009	
	Pension Benefits	Other Post Retirement Employee Benefits	Pension Benefits	Other Post Retirement Employee Benefits
Service cost	$ 84	$	$ 250	$ 9
Interest cost	1,336	23	1,327	44
Expected return on assets	(1,034)		(748)	
Amortization of net (gain) loss	274	(3)	381	(4)
Amortization of prior service cost		(35)		
Curtailment loss recognized			2	
Net periodic pension cost	$ 660	$ (15)	$ 1,212	$ 49

During the year ended December 31, 2010, the Company made contributions to its Pension Plan and Other Plans of $1,055 and expects to make contributions in 2011 of approximately $1,763.

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The benefit obligations, plan assets, funded status, and amounts recognized in the consolidated balance sheets were as follows:

	Year Ended December 31,			
	2010		2009	
	Pension Benefits	Other Post Retirement Employee Benefits	Pension Benefits	Other Post Retirement Employee Benefits
Change in projected benefit obligation (PBO):				
Benefit obligation at beginning of year	$ 22,382	$ 781	$ 20,896	$ 839
Service cost	84		250	9
Interest cost	1,336	23	1,327	44
Curtailment			2	
Benefits paid	(861)	(114)	(807)	(104)
Actuarial (gain) loss	1,917	31	798	(81)
Administrative expense	(97)		(84)	
Plan amendments		(345)		
Employee contributions		70		74
Benefit obligation at end of year	$ 24,761	$ 446	$ 22,382	$ 781
Change in plan assets:				
Fair value of plan assets at beginning of year	$ 13,730	$	$ 12,018	$
Benefit payments	(861)	(114)	(807)	(104)
Actual return on assets	2,256		2,603	
Administrative expense	(97)		(84)	
Employee contributions		70		74
Employer contribution	1,011	44		30
Fair value of plan assets at end of year	$ 16,039	$	$ 13,730	$
Funded status benefit obligation in excess of plan assets	$ (8,722)	$ (446)	$ (8,652)	$ (781)
Curtailment			2	
Prior service credit		(311)		
Unrecognized net actuarial loss (gain)	5,236	(73)	4,814	(108)
Net amount recognized at end of year	$ (3,486)	$ (830)	$ (3,836)	$ (889)

Amounts recognized in the consolidated balance sheets consisted of:

Accrued benefit obligation	$	(8,722)	$	(446)	$	(8,652)	$	(781)
Accumulated other comprehensive (income) loss		5,236		(384)		4,816		(108)
Net amount recognized at end of year	$	(3,486)	$	(830)	$	(3,836)	$	(889)

The accumulated benefit obligation for the Pension Plan was $24,761 and $22,382 as of December 31, 2010 and 2009, respectively. The accumulated benefit obligation is equal to the projected benefit obligation due to the curtailment that occurred in 2008. The accumulated benefit obligation for the Pension Plan was less than plan assets

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by $8,722 and $8,652 as of December 31, 2010 and 2009, respectively. As of December 31, 2010, the Company had no transition gains (losses) but recorded a prior service credit of $311 and actuarial (gains) losses of $455 in accumulated other comprehensive loss in the consolidated balance sheets.

The portion relating to the Pension Plan and Other Plans classified in accumulated other comprehensive loss is $4,852 as of December 31, 2010 and the portion classified in accumulated other comprehensive loss is $4,708 as of December 31, 2009. In 2011, the Company will recognize $(277) and $37, respectively, of (gains) losses from accumulated other comprehensive loss for the Company s Pension Plan and Other Plans.

The significant weighted average assumptions used for the years ended December 31, 2010 and 2009 were as follows:

	2010		2009	
	Pension Benefits	Other Post Retirement Employee Benefits	Pension Benefits	Other Post Retirement Employee Benefits
Discount rate for benefit obligations	5.50%	4.54%	6.04%	5.55%
Discount rate for net periodic benefit costs	6.04%	5.55%	6.18%	6.20%
Expected return on plan assets for net periodic benefit costs	7.50%	N/A	7.50%	N/A
Rate of compensation increase for benefit obligations	N/A	N/A	4.50%	N/A
Rate of compensation increase for net periodic benefit costs	N/A	N/A	4.50%	N/A

For measurement purposes, a 8.2% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2011. The rate was assumed to decrease by 0.20% per year for an ultimate rate of 4.5% for 2029 and remain at that level thereafter. An increase or decrease by one percentage point in the assumed healthcare cost trend rates would not have a material effect on the benefit obligation and service and interest cost components of benefit costs for the Other Plans as of December 31, 2010. The Company considered the historical returns and the future expectation for returns for each asset class, as well as the target asset allocation of the Pension Plan portfolio, to develop the expected long-term rate of return on plan assets.

The Company s Pension Plan asset allocations, as of December 31, 2010 and 2009 by asset category, are as follows:

	2010 Pension Benefits	2009 Pension Benefits
Cash	2%	2%
Equity	49%	66%

Foreign equities	12%	17%
Fixed income	37%	15%
Capital Preservation Portfolio	0%	0%
	100%	100%

Investment Policy

Our Pension Plan investment policy is set with specific consideration of return and risk requirements in relationship to the respective liabilities. Given the long term nature of our liabilities, the Pension Plan has the flexibility to manage a moderate level of risk. At the investment policy level, there are no specifically prohibited

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investments. However, within individual investment manager mandates, restrictions and limitations are contractually set to align with our investment objectives, ensure risk control, and limit concentrations.

We manage our portfolio to minimize any concentration of risk by allocating funds within asset categories. In addition, within a category we use different managers with various management objectives to eliminate any significant concentration of risk. Management believes there are no significant concentrations of risks associated with the investment assets.

The Pension Plan s asset allocation strategy is currently comprised of the following:

	2010	
Asset Class	**Range of Asset Allocations**	**Target Allocation**
Equities	25 35%	30%
Fixed income	45 55%	50%
Capital Preservation Portfolio	15 25%	20%

During 2010, we began the process to better align our investments with our liability as a result of the Pension Plan s curtailed status. We will complete this reallocation in 2011 as our investment consultant completes their evaluations and recommendations. Prior to 2010, our allocation strategy was comprised of the following:

	2009	
Asset Class	**Range of Asset Allocations**	**Target Allocation**
Cash	0 5%	Minimal
Fixed income	20 50%	35%
Equities	50 80%	65%

Trust assets will be invested in accordance with prudent expert standards as mandated by the Employee Retirement Income Security Act (ERISA). In the event market environments create asset exposures outside of the policy guidelines, reallocations will be made in an orderly manner to rebalance the investments and maximize the effectiveness of the Pension Plan asset allocation strategy. The Company s investment consultant 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 based on such factors as organizational stability, depth of resources, experience, investment strategy and process, performance expectations and fees.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid in the years indicated as of December 31, 2010:

	Pension Benefits	Other Post Retirement Employee Benefits
2011	$ 912	$ 73
2012	961	75
2013	1,018	58
2014	1,090	41
2015	1,190	43
2016 to 2020	7,281	142
Total	$ 12,452	$ 432

The Company participated in two multi-employer plans as a result of the acquisition of Penreco. The Company elected to withdraw from these plans in 2009 and made a final contribution of approximately $183 to the Penreco

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Local 710 Health, Welfare and Pension Funds plan and has agreed to the final settlement of approximately $1,863 for the Western Pennsylvania Teamsters and Employers Pension Fund to be paid over 30 years.

The Company s investments associated with its Pension Plan consist of investments that are publicly traded and for which market prices are readily available, thus these investments are categorized as Level 1. The Company s Pension Plan assets measured at fair value at December 31, 2010 and 2009 were as follows:

	Quoted Prices in Active Markets for Identical Assets (Level 1) December 31,	
	2010 Pension Benefits	2009 Pension Benefits
Cash	$ 347	$ 326
Equity	7,784	8,326
Foreign equities	1,890	2,736
Fixed income	6,018	2,342
Capital Preservation Portfolio		N/A
	$ 16,039	$ 13,730

14. Transactions with Related Parties

During the years ended December 31, 2010, 2009 and 2008, the Company had sales to related parties owned by a limited partner of $4,727, $3,208 and $7,973, respectively. Trade accounts and other receivables from related parties at December 31, 2010 and 2009 were $422 and $248, respectively. The Company also had purchases from related parties owned by a limited partner, excluding crude purchases related to the Legacy Resources Co., L.P. (Legacy Resources) agreements and director s and officers liability insurance premiums discussed below, during the years ended December 31, 2010, 2009 and 2008 of $1,480, $1,718 and $615, respectively. Accounts payable to related parties, excluding accounts payable related to the Legacy Resources agreements discussed below, at December 31, 2010 and 2009 were $1,246 and $1,015, respectively.

In May 2008, the Company began purchasing all of its crude oil requirements for its Princeton refinery on a just in time basis utilizing a market-based pricing mechanism from Legacy Resources. In addition, in January 2009, the Company entered into an agreement with Legacy Resources to begin purchasing certain of its crude oil requirements for its Shreveport refinery utilizing a market-based pricing mechanism from Legacy. In September 2009, the Company entered into a Crude Oil Supply Agreement with Legacy Resources (the Legacy Shreveport Agreement). Under the Legacy Shreveport Agreement, Legacy Resources supplies the Company s Shreveport refinery with a portion of its crude oil requirements on a just in time basis utilizing a market-based pricing mechanism. Legacy

Resources is owned in part by one of the Company s limited partners, an affiliate of the Company s general partner, the Company s chief executive officer and vice chairman of the board of our general partner, F. William Grube, and Jennifer G. Straumins, the Company s president and chief operating officer. The volume of crude oil purchased under the Legacy Shreveport Agreement fluctuates based on the volume of crude oil needed by the Shreveport refinery and can be up to 20,000 barrels per day. During the years ended December 31, 2010 and 2009 and 2008, the Company had crude oil purchases of $591,777, $390,231 and $140,180, respectively, from Legacy Resources. Accounts payable to Legacy Resources at December 31, 2010 and 2009 related to these agreements were $26,739 and $16,851, respectively.

Nicholas J. Rutigliano, a member of the board of directors of our general partner, founded and is the president of Tobias Insurance Group, Inc. (Tobias), a commercial insurance brokerage business, that has historically placed

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a portion of our insurance underwriting requirements, including our directors and officers liability insurance. The total premiums paid to Tobias by the Company for the years ended December 31, 2010, 2009 and 2008 were $638, $672 and $634, 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, 2010, 2009 and 2008.

15. Segments and Related Information

a. Segment Reporting

The Company has two reportable segments: Specialty Products and Fuel Products. The Specialty Products segment, which includes Penreco from its date of acquisition, produces a variety of lubricating oils, solvents and waxes. These products are sold to customers who purchase these products primarily as raw material components for basic automotive, industrial and consumer goods. The Fuel Products segment produces a variety of fuel and fuel-related products including gasoline, diesel and jet fuel. Because of the similar economic characteristics, certain operations have been aggregated for segment reporting purposes.

The accounting policies of the segments are the same as those described in the summary of significant accounting policies except that the Company evaluates segment performance based on income from operations. The Company accounts for intersegment sales and transfers at cost plus a specified mark-up. Reportable segment information is as follows:

Year Ended December 31, 2010	Specialty Products	Fuel Products	Combined Segments	Eliminations	Consolidated Total
Sales:					
External customers	$ 1,408,872	$ 781,880	$ 2,190,752	$	$ 2,190,752
Intersegment sales	775,366	39,410	814,776	(814,776)	
Total sales	$ 2,184,238	$ 821,290	$ 3,005,528	$ (814,776)	$ 2,190,752
Depreciation and amortization	74,157		74,157		74,157
Operating income (loss)	73,194	(1,704)	71,490		71,490
Reconciling items to net income:					
Interest expense					(30,497)
Debt extinguishment costs					