MARTIN MIDSTREAM PARTNERS LP
Form 10-K
March 03, 2014

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

FORM 10-K

Mark One	
ý	Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 For the fiscal year ended December 31, 2013
OR	
o	Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from _____ to _____.
Commission file number 000-50056
MARTIN MIDSTREAM PARTNERS L.P.
(Exact name of registrant as specified in its charter)

Delaware	05-0527861
State or other jurisdiction of incorporation or organization	(I.R.S. Employer Identification No.)

4200 Stone Road Kilgore, Texas 75662
(Address of principal executive offices) (Zip Code)

903-983-6200
(Registrant's telephone number, including area code)

_____

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 partnership interests	NASDAQ Global Select 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 ý No o

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 ý

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 the past 90 days.
Yes ý 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 ý 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 definition of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

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

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

As of June 30, 2013, 26,624,276 common units were outstanding. The aggregate market value of the common units held by non-affiliates of the registrant as of such date approximated $949,302,187 based on the closing sale price on that date. There were 26,622,276 of the registrant's common units outstanding as of March 3, 2014.

DOCUMENTS INCORPORATED BY REFERENCE: None.

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PART I

Item 1. Business

References in this annual report to “we,” “ours,” “us” or like terms when used in a historical context refer to the assets and operations of Martin Resource Management's business contributed to us in connection with our initial public offering on November 6, 2002. References in this annual report to “Martin Resource Management” refer to Martin Resource Management Corporation and its subsidiaries, unless the context otherwise requires. References in this annual report to the "Partnership" refer to Martin Midstream Partners L.P. and its subsidiaries, unless the content otherwise requires. You should read the following discussion of our financial condition and results of operations in conjunction with the consolidated financial statements and the notes thereto included elsewhere in this annual report. For more detailed information regarding the basis for presentation for the following information, you should read the notes to the consolidated financial statements included elsewhere in this annual report.

Forward-Looking Statements

This annual report on Form 10-K includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Statements included in this annual report that are not historical facts (including any statements concerning plans and objectives of management for future operations or economic performance, or assumptions or forecasts related thereto), are forward-looking statements. These statements can be identified by the use of forward-looking terminology including “forecast,” “may,” “believe,” “will,” “expect,” “anticipate,” “estimate,” “continue” or other similar words. These statements dis future expectations, contain projections of results of operations or of financial condition or state other “forward-looking” information. We and our representatives may from time to time make other oral or written statements that are also forward-looking statements.

These forward-looking statements are made based upon management's current plans, expectations, estimates, assumptions and beliefs concerning future events impacting us and therefore involve a number of risks and uncertainties. We caution that forward-looking statements are not guarantees and that actual results could differ materially from those expressed or implied in the forward-looking statements.

Because these forward-looking statements involve risks and uncertainties, actual results could differ materially from those expressed or implied by these forward-looking statements for a number of important reasons, including those discussed above in “Item 1A. Risk Factors – Risks Related to our Business.”

Overview

We are a publicly traded limited partnership with a diverse set of operations focused primarily in the United States (“U.S.”) Gulf Coast region. Our four primary business lines include:

- Terminalling and storage services for petroleum products and by-products including the refining, blending and packaging of finished lubricants;
- Natural gas liquids distribution services and natural gas storage;
- Sulfur and sulfur-based products gathering, processing, marketing, manufacturing and distribution; and
- Marine transportation services for petroleum products and by-products.

The petroleum products and by-products we collect, transport, store and market are produced primarily by major and independent oil and gas companies who often turn to third parties, such as us, for the transportation and disposition of these products. In addition to these major and independent oil and gas companies, our primary customers include independent refiners, large chemical companies, fertilizer manufacturers and other wholesale purchasers of these products. We operate primarily in the U.S. Gulf Coast region. This region is a major hub for petroleum refining, natural gas gathering and processing, and support services for the exploration and production industry.

We were formed in 2002 by Martin Resource Management, a privately-held company whose initial predecessor was incorporated in 1951 as a supplier of products and services to drilling rig contractors. Since then, Martin Resource Management has expanded its operations through acquisitions and internal expansion initiatives as its management identified

and capitalized on the needs of producers and purchasers of petroleum products and by-products and other bulk liquids. Martin Resource Management is an important supplier and customer of ours. As of December 31, 2013, Martin Resource Management owned 19.1% of our total outstanding common limited partner units. Furthermore, Martin Resource Management controls Martin Midstream GP LLC ("MMGP"), our general partner, by virtue of its 51% voting interest in MMGP Holdings, LLC ("Holdings"), the sole member of MMGP. MMGP owns a 2.0% general partner interest in us and all of our incentive distribution rights. Martin Resource Management directs our business operations through its ownership interests in and control of our general partner.

We entered into an omnibus agreement dated November 1, 2002, with Martin Resource Management (the "Omnibus Agreement") that governs, among other things, potential competition and indemnification obligations among the parties to the agreement, related party transactions, the provision of general administration and support services by Martin Resource Management and our use of certain of Martin Resource Management's trade names and trademarks. Under the terms of the Omnibus Agreement, the employees of Martin Resource Management are responsible for conducting our business and operating our assets.

The historical operation of our business segments by Martin Resource Management provides us with several decades of experience and a demonstrated track record of customer service across our operations. Our current lines of business have been developed and systematically integrated over this period of more than 60 years, including natural gas services (1950s); sulfur (1960s); marine transportation (late 1980s); and terminalling and storage (early 1990s). This development of a diversified and integrated set of assets and operations has produced a complementary portfolio of midstream services that facilitates the maintenance of long-term customer relationships and encourages the development of new customer relationships.

Primary Business Segments

Our primary business segments can be generally described as follows:

- Terminalling and Storage. We own or operate 30 marine shore-based terminal facilities and 17 specialty terminal facilities located in the U.S. Gulf Coast region that provide storage, refining, blending, packaging, and handling services for producers and suppliers of petroleum products and by-products, including the refining, blending and packaging of various grades and quantities of naphthenic lubricants and related products. Our facilities and resources provide us with the ability to handle various products that require specialized treatment, such as molten sulfur and asphalt. We also provide land rental to oil and gas companies along with storage and handling services for lubricants and fuels. We provide these terminalling and storage services on a fee basis primarily under long-term contracts. A significant portion of the contracts in this segment provide for minimum fee arrangements that are not based on the volumes handled.

- Natural Gas Services. We distribute natural gas liquids ("NGLs"). We purchase NGLs primarily from refineries and natural gas processors. We store NGLs in our supply and storage facilities for wholesale deliveries to propane retailers, refineries and industrial NGL users in Texas and the Southeastern U.S. We own a NGL pipeline, which spans approximately 200 miles from Kilgore, Texas to Beaumont, Texas. We own three NGL supply and storage facilities with an aggregate above-ground storage capacity of approximately 3,000 barrels and we lease approximately 2.2 million barrels of underground storage capacity for NGLs. We own six liquefied petroleum gas ("LPG") pressure barges, which are primarily used for product storage in our NGL distribution business. Additionally, through our ownership interests in Redbird Gas Storage LLC ("Redbird"), we are partners in a joint venture, Cardinal Gas Storage Partners LLC ("Cardinal"), which is focused on the development, construction, operation and management of natural gas storage facilities across northern Louisiana and Mississippi.

- Sulfur Services. We have developed an integrated system of transportation assets and facilities relating to sulfur services over the last 50 years. We process and distribute sulfur predominantly produced by oil refineries primarily

located in the U.S. Gulf Coast region. We handle molten sulfur on contracts that are tied to sulfur indices and tend to provide stable margins. We process molten sulfur into prilled or pelletized sulfur on take-or-pay fee contracts at our facilities in Port of Stockton, California and Beaumont, Texas. The sulfur we process and handle is primarily used in the production of fertilizers and industrial chemicals. We own and operate seven sulfur-based fertilizer production plants and one emulsified sulfur blending plant that manufactures primarily sulfur-based fertilizer products for wholesale distributors and industrial users. These plants are located in Illinois, Texas and Utah. Demand for our sulfur products exists in both the domestic and foreign markets, and we believe our asset base provides us with additional opportunities to handle increases in U.S. supply and access to foreign demand.

- Marine Transportation. We own a fleet of 39 inland marine tank barges, 25 inland push boats and four offshore tug and barge units that transport petroleum products and by-products largely in the U.S. Gulf Coast region. We provide these transportation services on a fee basis primarily under annual contracts and many of our customers have long standing contractual relationships with us. Our modernized asset base is attractive both to our existing customers as well as potential new customers. In addition, our fleet contains several vessels that reflect our focus on specialty products. For example, we are one of a very limited number of companies that can transport molten sulfur.

Recent Developments

We believe one of the rationales driving investment in master limited partnerships, including us, is the opportunity for distribution growth offered by the partnerships. Such distribution growth is a function of having access to liquidity in the financial markets used for incremental capital investment (development projects and acquisitions) to grow distributable cash flow.

We continually adjust our business strategy to focus on maximizing liquidity, maintaining a stable asset base which generates fee based revenues not sensitive to commodity prices, and improving profitability by increasing asset utilization and controlling costs. Over the past year, we have had access to the capital markets and have appropriate levels of liquidity and operating cash flows to adequately fund our growth. Over the next two years, we plan to increase expansion capital expenditures primarily in our Terminalling and Storage and Natural Gas Services segments.

Recent Acquisitions

Marine Transportation Equipment Purchase. On September 30, 2013, we acquired two previously leased inland tank barges from Martin Resource Management for $7.1 million. This transaction was funded with borrowings under our revolving credit facility.

Sulfur Production Facility. On August 5, 2013, we purchased a plant nutrient sulfur production facility in Cactus, Texas for $4.1 million. This transaction was funded with borrowings under our revolving credit facility.

NL Grease, LLC. On June 13, 2013, we acquired certain assets of NL Grease, LLC (“NLG”) for approximately $12.1 million. NLG is a Kansas City, Missouri based grease manufacturer that specializes in private-label packaging of commercial and industrial greases. This transaction was funded with borrowings under our revolving credit facility.

Martin Energy Trading LLC. During March 2013, we acquired 100% of the preferred interests in Martin Energy Trading LLC (“MET”), a subsidiary of Martin Resource Management, for $15.0 million. This transaction was funded with borrowings under our revolving credit facility.

NGL Marine Equipment Purchase. On February 28, 2013, we purchased from affiliates of Florida Marine Transporters, Inc., six liquefied petroleum gas ("LPG") pressure barges and two commercial push boats (“Florida Marine Assets”) for approximately $50.8 million. This transaction was funded with borrowings under our revolving credit facility.

Talen's Marine & Fuel LLC. On December 31, 2012, we acquired all of the outstanding membership interests in Talen's Marine & Fuel LLC (“Talen's”) from QEP Marine Fuel Investment, LLC and QEP Marine Fuel Holdings, Inc. (collectively referred to as “Quintana Energy Partners”) for $103.4 million, subject to certain post-closing adjustments. Simultaneous with the acquisition, we sold certain working capital-related assets to Martin Energy Services LLC (“MES”), a wholly-owned subsidiary of Martin Resource Management for $56.0 million, reducing our investment in Talen's to $47.4 million. This transaction was funded with borrowings under our revolving credit facility. In conjunction with its purchase of certain working capital-related assets, MES entered into various service agreements with Talen's pursuant to which we provide certain terminalling and marine services to MES.

Other Developments

Sale of general partner interest. On August 30, 2013, Martin Resource Management completed the sale of a 49% non-controlling voting interest (50% economic interest) in Holdings, the newly-formed sole member of MMGP, the general partner of the Partnership, to certain affiliated investment funds managed by Alinda Capital Partners ("Alinda"). Upon closing the transaction, Alinda appointed two representatives to serve on the board of directors of the general partner of the Partnership.

Debt Financing Activities

Amendment to Revolving Credit Facility. On March 28, 2013, we made certain strategic amendments to our credit facility which, among other things, increased our borrowing capacity from $400.0 million to $600.0 million and extended the maturity date of the facility from April 15, 2016 to March 28, 2018.

Issuance of 2021 Senior Unsecured Notes. On February 11, 2013, we completed a private placement of $250.0 million in aggregate principal amount of 7.250% senior unsecured notes due 2021 to qualified institutional buyers under Rule 144A. We received proceeds of approximately $245.1 million, after deducting initial purchasers' discounts and the expenses of the private placement. The proceeds were primarily used to repay borrowings under our revolving credit facility. On July 1, 2013, we filed a registration statement on Form S-4 with the Securities and Exchange Commission ("SEC") to exchange the notes for registered 7.250% senior unsecured notes due February 2021. The exchange offer was completed on July 31, 2013.

For a more detailed discussion regarding our debt financing activities, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Description of Our Long-Term Debt."

Subsequent Events

Redemption of 2018 Senior Unsecured Notes. On February 28, 2014, we announced that we will exercise a full redemption of the 2018 senior unsecured notes pursuant to the indenture, on or about April 1, 2014 at an aggregate redemption value of $182.8 million. We expect to fund the redemption under borrowings from our revolving credit facility.

Amendment to Revolving Credit Facility. On February 18, 2014, we increased the maximum amount of borrowings under our revolving credit facility from $600.0 million to $637.5 million by utilizing the accordion feature of our revolving credit facility.

Quarterly Distribution. On January 23, 2014, we declared a quarterly cash distribution of $0.785 per common unit for the fourth quarter of 2013, or $3.14 per common unit on an annualized basis, which was paid on February 14, 2014 to unitholders of record as of February 7, 2014.

Our Business Strategy

The key components of our business strategy are:

- Pursue Organic Growth Projects. We continually evaluate economically attractive organic expansion opportunities in new or existing areas of operation that will allow us to leverage our existing market position and increase the distributable cash flow from our existing assets through improved utilization and efficiency.

- Pursue Internal Organic Growth by Attracting New Customers and Expanding Services Provided to Existing Customers. We seek to identify and pursue opportunities to expand our customer base across all of our business segments. We generally begin a relationship with a customer by transporting, storing or marketing a limited range of products and services. We believe expanding our customer base and our service and product offerings to existing customers is an efficient and cost effective method of achieving organic growth in revenues and cash flow. We believe significant opportunities exist to expand our customer base and provide additional services and products to existing customers.

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Pursue Strategic Acquisitions. We continually monitor the marketplace to identify and pursue accretive acquisitions that expand the services and products we offer or that expand our geographic presence. After acquiring other businesses, we will attempt to utilize our industry knowledge, network of customers and suppliers and strategic asset base to operate the acquired businesses more efficiently and competitively, thereby increasing revenues and cash flow. We believe that our diversified base of operations provides multiple platforms for strategic growth through acquisitions.

Pursue Strategic Commercial Alliances. Many of our larger customers, which include major integrated energy companies, have established strategic alliances with midstream service providers such as us to address logistical and transportation problems or achieve operational synergies. We intend to pursue strategic commercial alliances with such customers in the future.

Competitive Strengths

We believe we are well positioned to execute our business strategy because of the following competitive strengths:
Fee Based Contracts. We generate a majority of our cash flow from fee-based contracts with our customers. In addition, a significant portion of these fee-based contracts consist of reservation charges or minimum fee arrangements, which reduce the volatility of a portion of our cash flows due to volume fluctuations.
Asset Base and Integrated Distribution Network. We operate a diversified asset base that enables us to offer our customers an integrated distribution network consisting of transportation, terminalling and storage and midstream logistical services while minimizing our dependence on the availability and pricing of services provided by third parties. Our integrated distribution network enables us to provide customers with a complementary portfolio of transportation, terminalling, distribution and other midstream services for petroleum products and by-products.
Strategically Located Assets. We are one of the largest operators of marine service shore-based terminals in the U.S. Gulf Coast region providing broad geographic coverage and distribution capability of our products and services to our customers. Our natural gas storage and NGL distribution and storage assets are located in areas highly desirable for our customers. Finally, many of our sulfur services assets are strategically located to source sulfur from the largest refinery sources in the U.S.
Specialized Transportation Equipment and Storage Facilities. We have the assets and expertise to handle and transport certain petroleum products and by-products with unique requirements for transportation and storage. For example, we own facilities and resources to transport a variety of specialty products, including ammonia, molten sulfur and asphalt. Some of these specialty products require treatment across a wide range of temperatures ranging between approximately -30 to +400 degrees Fahrenheit to remain in liquid form, which our facilities are designed to accommodate. We believe these capabilities help us enhance relationships with our customers by offering them services to handle their unique product requirements.
Strong Industry Reputation and Established Relationships with Suppliers and Customers. We believe we have established a reputation in our industry as a reliable and cost-effective supplier of services to our customers and have a track record of safe, efficient operation of our facilities. Our management has also established long-term relationships with many of our suppliers and customers. We believe we benefit from our management's reputation and track record and from these long-term relationships.
Financial Strength and Flexibility. We have historically financed our operations with a combination of debt and equity while maintaining a modest leverage profile, even in challenging business environments. Since our initial public offering, we have accessed the public equity markets eight times for approximately $539.3 million in total net proceeds, including capital contributions from our general partner. As of March 3, 2014, we have accessed the public debt markets two times for approximately $442.3 million in total net proceeds. We have also occasionally issued common units to Martin Resource Management in exchange for cash or assets.
Experienced Management Team and Operational Expertise. Members of our executive management team and the heads of our principal business lines have a significant amount of experience in the industries in which we operate. Our management team has a successful track record of creating internal growth and completing acquisitions. We believe our management team's experience and familiarity with our industry and businesses are important assets that assist us in implementing our business strategies.

Terminalling and Storage Segment

Industry Overview. The U.S. petroleum distribution system moves petroleum products and by-products from oil refineries and natural gas processing facilities to end users. This distribution system is comprised of a network of terminals, storage facilities, pipelines, tankers, barges, railcars and trucks. Terminals play a key role in moving these products throughout the distribution system by providing storage, blending and other ancillary services.

In the 1990s, the petroleum industry entered a period of consolidation. Refiners and marketers developed large-scale, cost-efficient operations resulting in several refinery acquisitions, combinations, alliances and joint ventures. This consolidation resulted in major oil companies integrating the various components of their businesses, including

terminalling and storage. However, major integrated oil companies later concentrated their focus and resources on their core competencies of exploration, production, refining and retail marketing and examined ways to lower their distribution costs. Additionally, the Federal Trade Commission required some divestitures of terminal assets in markets in which merged companies, alliances and

joint ventures were regarded as having excessive market power. As a result of these factors, oil and gas companies began to increasingly rely on third parties, such as us, to perform many terminalling and storage services.

Although many large energy and chemical companies own terminalling and storage facilities, these companies also use third-party terminalling and storage services. Major energy and chemical companies typically have a strong demand for terminals owned by independent operators when such terminals are strategically located at or near key transportation links, such as deep-water ports. Major energy and chemical companies also need independent terminal storage when their owned storage facilities are inadequate, either because of lack of capacity, the nature of the stored material or specialized handling requirements.

The Gulf Coast region is a major hub for petroleum refining. Approximately 50% of U.S. refining capacity exists in this region. Growth in the refining and natural gas processing industries has increased the volume of petroleum products and by-products that are transported within the Gulf Coast region, which consequently has increased the need for terminalling and storage services.

The marine and offshore oil and gas exploration and production industries use terminal facilities in the Gulf Coast region as shore bases that provide them logistical support services as well as provide a broad range of products, including fuel oil, lubricants, chemicals and supplies. The demand for these types of terminals, services and products is driven primarily by offshore exploration, development and production in the Gulf of Mexico. Offshore activity is greatly influenced by current and projected prices of oil and natural gas.

Specialty Petroleum Terminals. We own or operate 17 terminalling facilities providing storage and handling services for some or all of the following: anhydrous ammonia, asphalt, sulfur, sulfuric acid, fuel oil, crude oil and other petroleum products and by-products. Each of these terminals has storage capacity for petroleum products and by-products and assets to handle products transported by vessel, barge or truck. The location and composition of our terminals are structured to complement our other businesses and reflect our strategy to provide a broad range of integrated services in the handling and transportation of petroleum products and by-products. We primarily developed our terminalling and storage assets by acquiring existing terminalling and storage facilities and then customizing and upgrading these facilities as needed to integrate the facilities into our petroleum product and by-product transportation network and to more effectively service customers. We have also identified strategic locations near rail, waterways and pipelines and have developed our own terminal facilities. We expect to continue to acquire facilities, streamline their operations and customize and upgrade them as part of our growth strategy. We also anticipate continuing to develop our own facilities when strategically desirable locations are identified. We also continually evaluate opportunities to add services and increase access to our terminals to attract more customers and create additional revenues.

Our Tampa terminal is located on approximately 10 acres of land owned by the Tampa Port Authority that was leased to us under a 10-year lease that commenced on December 16, 2006 with two five-year options. Our Stanolind terminal is located on approximately 11 acres of land owned by us located on the Neches River in Beaumont, Texas. Our Neches terminal is a deep water marine terminal located near Beaumont, Texas, on approximately 50 acres of land owned by us. Our Corpus Christi, Texas Barge terminal is located on approximately 25 acres of land owned by us and has access to the waterfront via marine docks owned by the Port of Corpus Christi. Our Corpus Christi, Texas crude terminal is located on 10 acres leased from the Port of Corpus Christi under terms of a five-year lease commencing on May 18, 2011 with five five-year options.

At our Tampa, Neches, Stanolind and Corpus Christi terminals, our customers are primarily large oil refining and natural gas processing companies. We charge either a fixed monthly fee or a throughput fee for the use of our facilities based on the capacity of the applicable tank. We conduct a substantial portion of our terminalling and storage operations under long-term contracts, which enhances the stability and predictability of our operations and cash flow. We attempt to balance our short-term and long-term terminalling contracts in order to allow us to maintain a

consistent level of cash flow while maintaining flexibility to earn higher storage revenues when demand for storage space increases. In addition, a significant portion of the contracts for our specialty terminals provide for minimum fee arrangements that are not based on the volume handled.

In Channelview, Texas, we operate a terminal used for lubricant blending, storage, packaging and distribution. This terminal is used as our central hub for bulk lubricant distribution where we receive, package and ship lubricants to our terminals or directly to customers.

In Smackover, Arkansas, we own a refinery and terminal where we process crude oil into finished products that include naphthenic lubricants, distillates, asphalt and other intermediates. This process is dedicated to an affiliate of Martin Resource Management through a long-term tolling agreement based on throughput rates and a monthly reservation fee.

In Smackover, Arkansas, we own and operate a terminal used for lubricant blending, processing, packaging, marketing and distribution. This terminal is used as our central hub for branded and private label package lubricants where we receive, package and ship heavy-duty, passenger car, and industrial lubricants to a network of retailers and distributors. A secondary blending and packaging operation is owned in Kansas City, Kansas, that allows us to serve markets that we cannot out of our Smackover facility.

In Kansas City, Missouri, we own and operate a plant that specializes in the processing and packaging of private-label commercial and industrial greases.

In South Houston, Texas, we own an asphalt terminal whose use is dedicated to an affiliate of Martin Resource Management through a terminalling service agreement based on throughput rates.

In Port Neches, Texas, we own an asphalt terminal whose use is dedicated to an affiliate of Martin Resource Management through a terminalling service agreement based upon throughput rates.

In Omaha, Nebraska, we own an asphalt terminal whose use is dedicated to an affiliate of Martin Resource Management through a terminalling service agreement based on throughput rates.

In Beaumont, Texas we own a terminal where we receive natural gasoline via pipeline and then ship the product to our customers via other pipelines to which the facility is connected, referred to as the “Spindletop Terminal”. Our fees for the use of this facility are based on the number of barrels shipped from the terminal.

In Broussard, Louisiana, we own a lubricant terminal on leased land whose use is dedicated to an affiliate of Martin Resource Management through a terminalling service agreement based on throughput rates.

In Jennings, Louisiana, we own a lubricant terminal whose use is dedicated to an affiliate of Martin Resource Management through a terminalling service agreement based on throughput rates.

In Lake Charles, Louisiana, we own a lubricant terminal on leased land whose use is dedicated to an affiliate of Martin Resource Management through a terminalling service agreement based on throughput rates.

The following is a summary description of our shore-based specialty terminals:

Terminal	Location	Aggregate Capacity	Products	Description
Tampa (1)	Tampa, Florida	718,000 barrels	Asphalt, sulfur and fuel oil	Marine terminal, loading/unloading for vessels, barges, railcars and trucks
Stanolind	Beaumont, Texas	555,000 barrels	Asphalt, crude oil, sulfur, sulfuric acid and fuel oil	Marine terminal, marine dock for loading/unloading of vessels, barges, railcars and trucks
Neches	Beaumont, Texas	500,400 barrels	Molten sulfur, ammonia, asphalt, fuel oil, crude oil and sulfur-based fertilizer	Marine terminal, loading/unloading for vessels, barges, railcars and trucks
Corpus Christi Barge terminal	Corpus Christi, Texas	330,000 barrels	Fuel oil and diesel	Marine terminal, loading/unloading barges and vessels and unloading trucks
Corpus Christi crude terminal (2)	Corpus Christi, Texas	600,000 barrels	Crude oil	Marine terminal, loading/unloading barges and vessels, trucks, and pipeline

access

(1) This terminal is located on land owned by the Tampa Port Authority that was leased to us under a 10-year lease that expires in December 2016 with two five-year extension options.

(2) Our Corpus Christi, Texas crude terminal is located on 10 acres leased from the Port of Corpus Christi under terms of a five-year lease commencing on May 18, 2011 with five five-year options.

The following is a summary description of our non shore-based specialty terminals:

Terminal	Location	Aggregate Capacity	Products	Description
Channelview	Houston, Texas	44,000 sq. ft. Warehouse; 35,000 barrels	Lubricants	Lubricants blending and storage
Smackover Refinery	Smackover, Arkansas	7,500 barrels per day	Naphthenic lubricants, distillates, asphalt	Crude refining facility
Martin Lubricants	Smackover, Arkansas	235,000 sq. ft. Warehouse; 5.3 million gallons bulk storage	Gard, SynGard, and Xtreme brands, and private label packaged lubricants	Lubricants packaging facility
Martin Lubricants	Kansas City, Kansas	65,000 sq. ft. Warehouse; 1.5 million gallons bulk storage	Gard, SynGard, and Xtreme brands, and private label packaged lubricants	Lubricants packaging facility
Martin Lubricants (6)	Kansas City, Missouri	75,000 sq. ft. Warehouse; 0.2 million gallons bulk storage	Private-label commercial and industrial greases	Grease manufacturing and packaging facility
South Houston Asphalt	Houston, Texas	71,000 barrels	Asphalt	Asphalt processing and storage
Port Neches Asphalt	Port Neches, Texas	31,300 barrels	Asphalt	Asphalt processing and storage
Omaha Asphalt	Omaha, Nebraska	114,200 barrels	Asphalt	Asphalt processing and storage
Spindletop	Beaumont, Texas	90,000 barrels	Natural gasoline	Pipeline receipts and shipments
Broussard Bulk Facility (4)(5)	Broussard, Louisiana	43,000 sq. ft. Warehouse; 8,200 barrels	Lubricants, fuel	Lubricants and fuel storage
Jennings Bulk Plant (5)	Jennings, Louisiana	41,000 sq. ft. building; 3,700 barrels	Lubricants, fuel	Lubricants and fuel storage
Lake Charles (3)	Lake Charles, Louisiana	18,000 sq. ft.Warehouse; 6,400 barrels	Lubricants	Lubricants storage

(3) This terminal is located on land owned by third parties and leased under a lease that expires in January 2016 and can be extended by us through January 2021. This terminal was acquired from Martin Resource Management on January 31, 2011.

(4) This terminal is located on land owned by third parties and leased under a lease that expires in November 2015 and can be extended by us through November 2030.

(5) These terminals were acquired from the purchase of Talen's on December 31, 2012.

(6) This terminal contains a warehouse owned by third parties and leased under a lease that expires in December 2020 and can be extended by us for two successive five-year periods and was acquired from the purchase of the NLG assets on June 13, 2013.

Marine Shore-Based Terminals. We own or operate 30 marine shore-based terminals along the Gulf Coast from Theodore, Alabama to Corpus Christi, Texas. Our terminalling assets are located at strategic distribution points for the products we handle and are in close proximity to our customers. We are one of the largest operators of marine shore-based terminals in the Gulf Coast region. These terminals are used to distribute and market fuel and lubricants.

Additionally, full service terminals also provide shore bases for companies that are operating in the offshore exploration and production industry. Customers are primarily oil and gas exploration and production companies and oilfield service companies, such as drilling fluid companies, marine transportation companies and offshore construction companies. Shore bases typically provide logistical support, including the storing and handling of tubular goods, loading and unloading bulk materials, providing facilities from which major and independent oil companies can communicate with and control offshore operations and leasing dockside facilities to companies which provide complementary products and services such as drilling fluids and cementing services. We generate revenues from our terminals that have shore bases by fees that we charge our customers under land rental contracts for the use of our terminal facility for these shore bases. These contracts generally provide us a fixed land rental fee and additional rental fees that are determined based on a percentage of the sales value of the products and services delivered from the shore

base. In addition, Martin Resource Management, through contractual arrangements, pays us for terminalling and storage of fuels and lubricants at these terminal facilities.

Our 30 marine shore-based terminals are divided into two classes of terminals: (i) full service terminals and (ii) fuel and lubricant terminals.

Full Service Terminals. We own or operate 10 full service terminals. These facilities provide logistical support services and storage and handling services for fuel and lubricants. The significant difference between our full service terminals and our fuel and lubricant terminals is that our full service terminals generate additional revenues by providing shore bases to support our customer's operating activities related to the offshore exploration and production industry. One typical use for our shore bases is for drilling fluids manufacturers to manufacture and sell drilling fluids to the offshore drilling industry. Offshore drilling companies may also set up service facilities at these terminals to support their offshore operations. Customers of our full service terminals are primarily oil and gas exploration and production companies, oilfield service companies such as drilling fluids companies, marine transportation companies and offshore construction companies.

The following is a summary description of our 10 full service terminals:

Terminal	Location	Aggregate Capacity (barrels)
Amelia-2 (3)(4)	Amelia, Louisiana	13,000
Cameron East (2)	Cameron, Louisiana	32,000
Dock 193 (7)(11)	Gueydan, Louisiana	13,000
Fourchon-15 (3)(6)	Fourchon, Louisiana	6,500
Freshwater City (7)(8)(9)	Freshwater City, Louisiana	7,400
Harbor Island (1)	Harbor Island, Texas	6,400
Intracoastal City-2 (3)(5)	Intracoastal City, Louisiana	12,500
Pelican Island	Galveston, Texas	88,600
Theodore	Theodore, Alabama	20,000
Venice (3)(10)	Venice, Louisiana	25,000

(1) A portion of this terminal is located on land owned by a third party and leased under a lease that expires in January 2015.
(2) This terminal is located on land owned by third parties and leased under a lease that expires in March 2017 and can be extended by us through February 2022.
(3) These terminals were acquired from Martin Resource Management on January 31, 2011.
(4) This terminal is located on land owned by a third party and leased under a lease that expires in August 2018 and can be extended by us through August 2023.
(5) This terminal is located on land owned by a third party and leased under a lease that expires in December 2015 and can be extended by us through December 2025.
(6) This terminal is located on land owned by a third party and leased under a lease that expires in February 2017.
(7) These terminals were acquired from the purchase of Talen's on December 31, 2012.
(8) This terminal is located on land owned by a third party and leased under a lease that expires in March 2017.
(9) This terminal has a warehousing agreement with a third party and under a lease that expires in March 2017.
(10) This terminal is located on land owned by third parties and leased under multiple leases that expire in September 2017 and can be extended by us through December 2027
(11) A portion of this terminal is located on land owned by a third party and leased under a lease that expires in May 2014 and can be extended by us through May 2016.

Fuel and Lubricant Terminals. We own or operate 20 lubricant and fuel terminals located in the Gulf Coast region that provide storage and handling services for lubricants and fuel oil.

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The following is a summary description of our fuel and lubricant terminals:

Terminal	Location	Aggregate Capacity (barrels)
Berwick (1)	Berwick, Louisiana	25,000
Cameron West (5)	Cameron, Louisiana	18,000
Cameron-7 (9)(19)	Cameron, Louisiana	15,500
Cameron-8 (9)(6)	Cameron, Louisiana	32,000
Dulac (9)(11)	Dulac, Louisiana	15,300
Fourchon (8)	Fourchon, Louisiana	80,900
Fourchon 16 (9)(16)	Fourchon, Louisiana	11,200
Fourchon 17(9)(12)	Fourchon, Louisiana	40,900
Fourchon-T (4)(10)	Fourchon, Louisiana	39,100
Freeport	Freeport, Texas	8,300
Galveston-T (4)(18)	Galveston Texas	10,400
Intracoastal City (7)(21)	Intracoastal City, Louisiana	30,600
Lake Charles-T (4)(17)	Lake Charles, Louisiana	16,500
Morgan City 33 (9)(15)(21)	Morgan City, Louisiana	0
Morgan City DWC 31(9)(14)	Morgan City, Louisiana	28,200
Pascagoula (18)	Pascagoula, Mississippi	11,000
Port Arthur (4)(20)	Port Arthur, Texas	15,800
Port O'Connor (2)	Port O'Connor, Texas	7,000
River Ridge (9)(13)	River Ridge, Louisiana	8,700
Sabine Pass (3)(21)	Sabine Pass, Texas	0

(1) This terminal is located on land owned by third parties and leased under a lease that expires in September 2017.

(2) This terminal is located on land owned by a third party and leased under a lease that expires in March 2014. We intend to extend this lease.

(3) This terminal is located on land owned by a third party and leased under a lease that expires in September 2016 and can be extended by us through September 2036.

(4) These terminals were acquired from the purchase of Talen's on December 31, 2012.

(5) This terminal is located on land owned by a third party and leased under a lease that expires in February 2018 and can be extended by us through February 2033.

(6) This terminal is located on land owned by a third party and leased under a lease that expires in July 2016 and can be extended by us through July 2036.

(7) A portion is leased pursuant to a month-to-month throughput agreement and a portion is under lease, which expires April of 2014. We intend to renew the lease.

(8) This terminal is located on land owned by a third party at which we throughput lubricants and fuel oil pursuant to an agreement that expires in May 2027.

(9) These terminals were acquired from Martin Resource Management on January 31, 2011.

(10) This terminal is located on land owned by a third party at which we throughput lubricants and fuel oil pursuant to an agreement that expires in October 2018 and can be extended by us through October 2038.

(11) This terminal is located on land owned by third parties and leased under a lease that expires in December 2021 and can be extended by us through December 2041.

(12) This terminal is located on land owned by third parties and leased under a lease that expires in December 2018 and can be extended by us through December 2023.

(13) This terminal is located on land owned by third parties and leased under multiple leases that expire in April 2019 and February 2020.

(14) This terminal is located on land owned by third parties and leased under a lease that expires in December 2014 and can be extended by us through December 2034. In addition, there is an office sublease that expires December 2014 and can be extended through December 2019.

(15)

This terminal is located on land owned by third parties and leased under a lease that expires in May 2014, Notice of Termination executed in September of 2013.

(16) This terminal is located on land owned by third parties and leased under multiple leases that expires in July 2017, July 2016, and March 2017. These leases can be extended by us through July 2022, July 2026, and March 2022, respectively.

(17) This terminal is located on land owned by third parties and leased under a lease that expires in April 2018 and can be extended by us through April 2023.
(18) These terminals were converted from full services terminals to fuel and lube terminals during 2013.
(19) This terminal is located on land owned by a third party and leased under a lease that expires in July 2017 and can be extended by us through July 2027.
(20) This terminal is located on land owned by third parties and leased under a lease that expires in November 2015 and can be extended by us through November 2025.
(21) These terminals are currently in caretaker status.

Competition. We compete with independent terminal operators and major energy and chemical companies that own their own terminalling and storage facilities. We believe many customers prefer to contract with independent terminal operators rather than terminal operators owned by integrated energy and chemical companies that may have refining or marketing interests that compete with the customers.

Independent terminal owners generally compete on the basis of the location and versatility of terminals, service and price. A favorably-located terminal has access to various cost effective transportation modes, both to and from the terminal, such as waterways, railroads, roadways and pipelines. Terminal versatility depends upon the operator's ability to handle diverse products, some of which have complex or specialized handling and storage requirements. The service function of a terminal includes, among other things, the safe storage of product at specified temperature, moisture and other conditions and receiving and delivering product to and from the terminal. All of these services must be in compliance with applicable environmental and other regulations.

We believe we successfully compete for terminal customers because of the strategic location of our terminals along the Gulf Coast, our integrated transportation services, our reputation, the prices we charge for our services and the quality and versatility of our services. Additionally, while some companies have significantly more terminalling and storage capacity than us, not all terminalling and storage facilities located in the markets we serve are equipped to properly handle specialty products such as asphalt, sulfur and anhydrous ammonia. As a result, our facilities typically command higher terminal fees when compared to fees charged for terminalling and storage of other petroleum products.

The principal competitive factors affecting our terminals, which provide fuel and lubricants distribution and marketing, as well as shore bases at certain terminals, are the locations of the facilities, availability of competing logistical support services and the experience of personnel and dependability of service. The distribution and marketing of our lubricant products is brand sensitive and we encounter brand loyalty competition. Shore base rental contracts are generally long-term contracts and provide more protection from competition. Our primary competitors for both lubricants and shore bases include several independent operations as well as major companies that maintain their own similarly equipped marine terminals, shore bases and fuel and lubricant supply sources.

Natural Gas Services Segment

Industry Overview. NGLs are produced through natural gas processing. They are also a by-product of crude oil refining. NGLs include ethane, propane, normal butane, iso butane and natural gasoline.

Ethane is almost entirely used as a petrochemical feedstock in the production of ethylene and propylene. Propane is used as a petrochemical feedstock in the production of ethylene and propylene, as a fuel for heating, for industrial applications, as motor fuel and as a refrigerant. Normal butane is used as a petrochemical feedstock, as a blend stock for motor gasoline and as a component in aerosol propellants. Normal butane can also be made into iso butane through isomerization. Iso butane is used in the production of motor gasoline, alkylation and as a component in aerosol propellants. Natural gasoline is used as a component of motor gasoline, as a petrochemical feedstock and as a diluent.

Facilities. We purchase NGLs primarily from major domestic oil refiners and natural gas processors. We transport NGLs using Martin Resource Management's land transportation fleet or by contracting with common carriers, owner-operators and railroad tank cars. We typically enter into annual contracts with independent retail propane distributors to deliver their estimated annual volume requirements based on prevailing market prices. We believe dependable delivery is very important to these customers and in some cases may be more important than price. We ensure adequate supply of NGLs through:

- storage of NGLs purchased in off-peak months;

- efficient use of the transportation fleet of vehicles owned by Martin Resource Management; and

•product management expertise to obtain supplies when needed.

The following is a summary description of our owned and leased NGL facilities:

NGL Facility	Location	Capacity	Description
Wholesale terminals	Arcadia, Louisiana (1)	2,200,000 barrels	Underground storage
	Breaux Bridge, Louisiana (2)	555,000 barrels	Underground storage
	Hattiesburg, Mississippi (2)	40,000 barrels	Underground storage
	Mt. Belvieu, Texas (2)	135,000 barrels	Underground storage
Retail terminals	Kilgore, Texas	90,000 gallons	Retail propane distribution
	Longview, Texas	30,000 gallons	Retail propane distribution
	Henderson, Texas	12,000 gallons	Retail propane distribution

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(1) We lease our underground storage at Arcadia, Louisiana, from Martin Resource Management under a year-to-year product storage agreement.

(2) We lease our underground storage at Breaux Bridge, Louisiana, Hattiesburg, Mississippi, and Mont Belvieu, Texas, from third parties under one-year lease agreements.

Our NGL customers that utilize these assets consist of refiners, industrial processors and retail propane distributors. For the year ended December 31, 2013, we sold approximately 88% of our NGL volume to refiners and industrial processors and approximately 12% of our NGL volume to independent retail propane distributors located in Texas and the southeastern U.S.

NGL Marine Storage. In addition to the above facilities, we also own six LPG pressure barges, which we acquired during February of 2013. These assets are used primarily for storage and each has a capacity of 16,101 barrels.

Competition. We compete with large integrated NGL producers and marketers, as well as small local independent marketers. NGLs compete primarily with natural gas, electricity and fuel oil as an energy source, principally on the basis of price, availability and portability.

Seasonality. The level of NGL supply and demand is subject to changes in domestic production, weather, inventory levels and other factors. While production is not seasonal, residential, refinery, and wholesale demand is highly seasonal. This imbalance causes increases in inventories during summer months when consumption is low and decreases in inventories during winter months when consumption is high. If inventories are low at the start of the winter, higher prices are more likely to occur during the winter. Additionally, abnormally cold weather can put extra upward pressure on prices during the winter because there are less readily available sources of additional supply except for imports, which are less accessible and may take several weeks to arrive. General economic conditions and inventory levels have a greater impact on industrial and refinery use of NGLs than the weather.

We generally maintain consistent margins in our natural gas services business because we attempt to pass increases and decreases in the cost of NGLs directly to our customers. We generally try to coordinate our sales and purchases of NGLs based on the same daily price index of NGLs in order to decrease the impact of NGL price volatility on our profitability.

Redbird Gas Storage

Through our ownership interests in Redbird, we formed Cardinal, a joint venture with Energy Capital Partners "ECP", which is focused on the development, construction, operation and management of natural gas storage facilities across northern Louisiana and Mississippi. At December 31, 2013, we owned an unconsolidated 42.21% interest in Cardinal. Through Redbird, we have the ability to invest in gas storage development projects at the Cardinal level. The Cardinal facilities are discussed below as follows:

Arcadia Gas Storage, LLC ("Arcadia"), located in Bienville Parish, Louisiana, is in service with 17.5 billion cubic feet ("bcf") of working storage capacity, of which 76% is contracted under firm storage service agreements. As of December 31, 2013, the weighted average remaining term of our existing portfolio of third party firm storage contracts was approximately 3.6 years.

Monroe Gas Storage Company, LLC ("Monroe"), located in Monroe County, Mississippi, is in service with approximately 7.0 bcf of working storage capacity, all of which is contracted under firm storage service agreements. As of December 31, 2013, the weighted average remaining term of our existing portfolio of third party firm storage contracts was approximately 1.0 year.

Perryville Gas Storage, LLC ("Perryville"), located in Franklin Parish, Louisiana, is in service with approximately 8.7 bcf of working storage capacity, of which 98% is contracted under firm storage service agreements. As of December 31, 2013, the weighted average remaining term of our existing portfolio of third party firm storage contracts was approximately 5.0 years.

Cadeville Gas Storage, LLC ("Cadeville"), located in Ouachita Parish, Louisiana, is in service with approximately 17.0 bcf of working storage capacity, of which 100% is contracted under firm storage service agreements. As of December 31, 2013, the weighted average remaining term of our existing portfolio of third party firm storage contracts was approximately 9.4 years.

These facilities were developed to provide producers, end users, local distribution companies, pipelines and energy marketers with high deliverability storage services and hub services.

Natural gas storage facilities provide a staging and warehousing function for seasonal swings in demand relative to supply, as well as an essential reliability cushion against disruptions in natural gas supply, demand and transportation by allowing natural gas to be injected into, withdrawn from or warehoused in such storage facilities as dictated by market conditions. The long term demand for storage services in the U.S. is driven primarily by the long-term demand for natural gas and the overall lack of balance between the supply of and demand for natural gas on a seasonal, monthly, daily or other basis. In general and on a long term basis, to the extent the overall demand for natural gas increases and such growth includes higher demand from seasonal or weather-sensitive end-users (such as gas-fired power generators and residential and commercial consumers), demand for natural gas storage services should also grow. In addition, any factors that contribute to more frequent and severe imbalances between the supply of and demand for natural gas, whether caused by supply or demand fluctuations, should increase the need for and the value of storage services. On a short term basis, storage demand and values are also significantly influenced by operational imbalances, near term seasonal spreads, shorter term spreads and basis differentials.

Sulfur Services Segment

Industry Overview. Sulfur is a natural element and is required to produce a variety of industrial products. In the U.S., approximately 10 million tons of sulfur are consumed annually with the Tampa, Florida area being the largest single market. Currently, all sulfur produced in the U.S. is "recovered sulfur," or sulfur that is a by-product from oil refineries and natural gas processing plants. Sulfur production in the U.S. is principally located along the Gulf Coast, along major inland waterways and in some areas of the western U.S.

Sulfur is an important plant nutrient and is primarily used in the manufacture of phosphate fertilizers with the balance used for industrial purposes. The primary application of sulfur in fertilizers occurs in the form of sulfuric acid. Burning sulfur creates sulfur dioxide, which is subsequently oxidized and dissolved in water to create sulfuric acid. The sulfuric acid is then combined with phosphate rock to make phosphoric acid, the base material for most high-grade phosphate fertilizers.

Sulfur-based fertilizers are manufactured chemicals containing nutrients known to improve the fertility of soils. Nitrogen, phosphorus, potassium and sulfur are the four most important nutrients for crop growth. These nutrients are found naturally in soils. However, soils used for agriculture become depleted of these nutrients and frequently require fertilizers rich in these essential nutrients to restore fertility.

Industrial sulfur products (including sulfuric acid) are used in a wide variety of industries. For example, these products are used in power plants, paper mills, auto and tire manufacturing plants, food processing plants, road construction, cosmetics and pharmaceuticals.

Our Operations and Products. We have an integrated system of transportation assets and facilities relating to our sulfur services. We gather molten sulfur from refiners, primarily located on the Gulf Coast, and from natural gas processing plants, primarily located in the southwestern U.S. We transport sulfur by inland and offshore barges, railcars and trucks. In the U.S., recovered sulfur is mainly kept in liquid form from production to usage at a temperature of approximately 275 degrees Fahrenheit. Because of the temperature requirement, the sulfur industry uses specialized equipment to store and transport molten sulfur. We have the necessary assets and expertise to handle the unique requirements for transportation and storage of molten sulfur.

The terms of our commercial sulfur contracts typically range from one to five years in length. We handle molten sulfur on cost-plus contracts and margin-based contracts, and the prices in such contracts are usually tied to a published market indicator and fluctuate according to the price movement of the indicator. We also provide barge transportation and tank storage services to large integrated oil companies that produce sulfur and fertilizer manufacturers that consume sulfur under transportation and storage contracts with remaining terms from one to two years in duration.

The sulfur prilling assets located at the Port of Stockton in California are used to process (prill) molten sulfur into pellets. The Stockton facility can process approximately 1,000 metric tons of molten sulfur per day and the resulting dry pellets are stored in bulk until sold into certain U.S. and international agricultural markets. In 2006, we completed the construction of a sulfur priller at our Neches facility in Beaumont, Texas with construction of a second priller completed in 2009. Forming capacity was further increased in 2012 with the addition of a granulator. The two Beaumont prillers along with the granulator have the capacity to process approximately 5,500 metric tons of molten sulfur per day. We process molten sulfur into formed sulfur on take-or-pay fee contracts, providing refiners access to the export market for the sale of their residual sulfur.

In September 2007, we completed construction of a sulfuric acid production facility at our Plainview, Texas location. This facility processes molten sulfur to produce approximately 150,000 tons of sulfuric acid per year. This acid production provides a dedicated supply of raw material sulfuric acid to our ammonium sulfate production plant that was completed in March of 2011. The ammonium sulfate plant produces approximately 400 tons per day of quality ammonium sulfate and is marketed to our customers throughout the U.S. The sulfuric acid produced and not consumed by the captive ammonium sulfate production is sold to Martin Resource Management which markets the excess production to third parties.

Fertilizer and related sulfur products are a natural extension of our molten sulfur business because of our access to sulfur and our distribution capabilities. These products allow us to leverage the Sulfur Services segment of our business. Our annual fertilizer and industrial sulfur products sales have grown from approximately 62,000 tons in 1997 to approximately 273,000 tons in 2013 as a result of acquisitions and internal growth.

In the U.S., fertilizer is generally sold to farmers through local dealers. These dealers are typically owned and supplied by much larger wholesale distributors. We sell to these wholesale distributors. Our industrial sulfur products are marketed primarily in the southern U.S., where many paper manufacturers and power plants are located. Our products are sold in accordance with price lists that vary from state to state. These price lists are updated periodically to reflect changes in seasonal or competitive prices. We transport our fertilizer and industrial sulfur products to our customers using third-party common carriers. We utilize rail shipments for large volume and long distance shipments where available.

We manufacture and market the following sulfur-based fertilizer and related sulfur products:

- Plant nutrient sulfur products. We produce plant nutrient and agricultural ground sulfur products at our two facilities in Odessa, Texas. We also produce plant nutrient sulfur at our facilities in Seneca, Illinois and Cactus, Texas. Our plant nutrient sulfur product is a 90% degradable sulfur product marketed under the Disper-Sul® trade name and sold throughout the U.S. to direct application agricultural markets. Our agricultural ground sulfur products are used primarily in the western U.S. on grapes and vegetable crops.

- Ammonium sulfate products. We produce various grades of ammonium sulfate including granular, coarse and standard grades, a 40% ammonium sulfate solution. These products primarily serve direct application agricultural markets. We blend our ammonium sulfate to make custom grades of lawn and garden fertilizer at our facility in Salt Lake City, Utah. We package these custom grade products under both proprietary and private labels and sell them to

major retail distributors and other retail customers of these products.

- Industrial sulfur products. We produce industrial sulfur products such as elemental pastille sulfur, industrial ground sulfur products, and emulsified sulfur. We produce elemental pastille sulfur at our two Odessa, Texas facilities and at our Seneca, Illinois facility. Elemental pastille sulfur is used to increase the efficiency of the coal-fired precipitators in the power industry. These industrial ground sulfur products are also used in a variety of dusting and wettable sulfur applications such as rubber manufacturing, fungicides, sugar and animal feeds. We produce emulsified sulfur at our Texarkana, Texas facility. Emulsified sulfur is primarily used to control the sulfur content in the pulp and paper manufacturing processes.

- Liquid sulfur products. We produce ammonium thiosulfate at our Neches terminal facility in Beaumont, Texas. This agricultural sulfur product is a clear liquid containing 12% nitrogen and 26% sulfur. This product serves as a liquid plant nutrient used directly through spray rigs or irrigation systems. It is also blended with other nitrogen

phosphorus potassium “NPK” liquids or suspensions as well. Our market is predominantly the Mid-South U.S. and Coastal Bend area of Texas.

Our Sulfur Services Facilities.

We own 56 railcars and lease 116 railcars equipped to transport molten sulfur. We own the following major marine assets and use them to transport molten sulfur from our Beaumont, Texas terminal to our Tampa, Florida terminal as well as provide third party marine transportation services to others:

Asset	Class of Equipment	Capacity/Horsepower	Products Transported
Margaret Sue	Offshore tank barge	10,450 long tons	Molten sulfur
M/V Martin Explorer	Offshore tugboat	7,200 horsepower	N/A
M/V Martin Express	Inland push boat	1,200 horsepower	N/A
MGM 101	Inland tank barge	2,450 long tons	Molten sulfur
MGM 102	Inland tank barge	2,450 long tons	Molten sulfur

We own the following sulfur forming facilities as part of our sulfur services business:

Terminal	Location	Daily Production Capacity	Products Stored
Neches	Beaumont, Texas	5,500 metric tons per day	Molten, prilled and granulated sulfur
Stockton	Stockton, California	1,000 metric tons per day	Molten and prilled sulfur

We lease 112 railcars to transport our fertilizer products. We own the following manufacturing plants as part of our sulfur services business:

Facility	Location	Capacity	Description
Fertilizer plant	Plainview, Texas	150,000 tons/year	Fertilizer production
Fertilizer plant	Beaumont, Texas	110,000 tons/year	Liquid sulfur fertilizer production
Fertilizer plants (two)	Odessa, Texas	70,000 tons/year	Dry sulfur fertilizer production
Fertilizer plant	Seneca, Illinois	36,000 tons/year	Dry sulfur fertilizer production
Fertilizer plant	Salt Lake City, Utah	25,000 tons/year	Blending and packaging
Fertilizer plant	Cactus, Texas	20,000 tons/year	Dry sulfur fertilizer production
Industrial sulfur plant	Texarkana, Texas	18,000 tons/year	Emulsified sulfur production
Sulfuric acid plant	Plainview Texas	150,000 tons/year	Sulfuric acid production

Competition. We own one of the four vessels currently used to transport molten sulfur between U.S. ports on the Gulf of Mexico and Tampa, Florida. Six phosphate fertilizer manufacturers together consume a vast majority of the sulfur produced in the U.S., which they purchase from resellers as well as directly from producers. We compete primarily with U.S. producers that sell directly to consumers with access to transportation and storage assets as well as foreign suppliers from Mexico or Venezuela that may sell into the Florida market. Our sulfur-based fertilizer products compete with several large fertilizer and sulfur products manufacturers. However, the close proximity of our manufacturing plants to our customer base is a competitive advantage for us in the markets we serve and allows us to minimize freight costs and respond quickly to customer requests. Our sulfuric acid products compete with regional producers and importers in the South and Southwest portion of the U.S. from Louisiana to California.

Seasonality. Sales of our agricultural fertilizer products are partly seasonal as a result of increased demand during the growing season.

Marine Transportation Segment

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Industry Overview. The U.S. inland waterway system is a vast and heavily used transportation system. This inland waterway system is composed of a network of interconnected rivers and canals that serve as water highways and is used to transport vast quantities of products annually. This waterway system extends approximately 26,000 miles, of which 12,000 miles are generally considered significant for domestic commerce.

The Gulf Coast region is a major hub for petroleum refining. The petroleum refining process generates products and by-products that require transportation in large quantities from the refinery or processor. Convenient access to and use of this waterway system by the petroleum and petrochemical industry is a major reason for the current location of U.S. refineries and petrochemical facilities. The marine transportation industry uses push boats and tugboats as power sources and tank barges for freight capacity. The combination of the power source and tank barge freight capacity is called a tow.

Marine Fleet. We utilize a fleet of inland and offshore tows that provide marine transportation of petroleum products and by-products produced in oil refining and natural gas processing. Our marine transportation business operates coastwise along the Gulf of Mexico and East Coast and on the U.S. inland waterway system, primarily between domestic ports along the Gulf of Mexico, Intracoastal Waterway, the Mississippi River system and the Tennessee-Tombigbee Waterway system. Additionally, we participate in Caribbean, Central America, and South American transport. Our inland tows generally consist of one push boat and one to three tank barges, depending upon the horsepower of the push boat, the river or canal capacity and conditions, and customer requirements. Each of our offshore tows consist of one tugboat, with much greater horsepower than an inland push boat, and one large tank barge. We transport asphalt, fuel oil, gasoline, sulfur and other bulk liquids.

The following is a summary description of the marine vessels we use in our marine transportation business:

Class of Equipment	Number in Class	Capacity/Horsepower	Description of Products Carried
Inland tank barges	13	Under 20,000 barrel	Asphalt, crude oil, fuel oil, gasoline and sulfur
Inland tank barges	26	20,000 - 30,000 barrel	Asphalt, crude oil, fuel oil and gasoline
Inland push boats	25	800 - 3,800 horsepower	N/A
Offshore tank barges	4	45,000 barrel and 95,000 barrel	Asphalt, fuel oil and NGLs
Offshore tugboats	4	2,400 - 7,200 horsepower	N/A

Our largest marine transportation customers include major and independent oil and gas refining companies, petroleum marketing companies and Martin Resource Management. We conduct our marine transportation services on a fee basis primarily under annual contracts.

We are a party to a marine transportation agreement under which we provide marine transportation services to Martin Resource Management on a spot contract basis at applicable market rates. Effective each January 1, this agreement automatically renews for consecutive one-year periods unless either party terminates the agreement by giving written notice to the other party at least 60 days prior to the expiration of the then-applicable term.

Competition. We compete primarily with other marine transportation companies. We believe we compete favorably with our competitors. Competition in this industry has historically been based primarily on price. However, we believe customers are placing an increased emphasis on safety, environmental compliance, quality of service and the availability of a single source of supply of services. Specifically, we believe customers are increasingly seeking suppliers that can offer marine, land, rail and terminal distribution services while providing a high level of flexibility, health, safety, environmental and financial responsibility, adequate insurance and quality of services consistent with the customer’s standards. We operate a diversified asset base that, together with the services provided by Martin

Resource Management, enables us to offer our customers an integrated distribution network consisting of transportation, terminalling, distribution and midstream logistical services for petroleum products and by-products.

In addition to competitors that provide marine transportation services, we also compete with providers of other modes of transportation, such as rail tank cars, tractor-trailer tank trucks and, to a lesser extent, pipelines. We believe we offer a competitive advantage over rail tank cars and tractor-trailer tank trucks because marine transportation is a more efficient, and generally less expensive, mode of transporting petroleum products and by-products. For example, a typical two inland barge unit carries a volume of product equal to approximately 80 railcars or 250 tanker trucks. Pipelines generally provide a less expensive form of transportation than marine transportation. However, pipelines are not able to transport most of the products

we transport and are generally a less flexible form of transportation because they are limited to the fixed point-to-point distribution of commodities in high volumes over extended periods of time.

Our Relationship with Martin Resource Management

Martin Resource Management is engaged in the following principal business activities:

- providing land transportation of various liquids using a fleet of trucks and road vehicles and road trailers;
- distributing fuel oil, asphalt, sulfuric acid, marine fuel and other liquids;
- providing marine bunkering and other shore-based marine services in Alabama, Louisiana, Florida, Mississippi and Texas;
- operating a crude oil gathering business in Stephens, Arkansas;
- providing crude oil gathering, refining, and marketing services of base oils, asphalt, and distillate products in Smackover, Arkansas;
- operating an underground NGL storage facility in Arcadia, Louisiana;
- operating an environmental consulting company;
- operating an engineering services company;
- supplying employees and services for the operation of our business;
- operating a natural gas optimization business;
- operating, for its account and our account, the docks, roads, loading and unloading facilities and other common use facilities or access routes at our Stanolind terminal; and
- operating, solely for our account, the asphalt facilities in Omaha, Nebraska, Port Neches, Texas and South Houston, Texas.

We are and will continue to be closely affiliated with Martin Resource Management as a result of the following relationships.

Ownership

Martin Resource Management owns an approximate 19.1% limited partnership interest in us. In addition, Martin Resource Management controls MMGP, our general partner, by virtue of its 51% voting interest in Holdings, the sole member of MMGP. MMGP owns a 2.0% general partner interest in us and all of our incentive distribution rights.

Management

Martin Resource Management directs our business operations through its ownership interests in and control of our general partner. We benefit from our relationship with Martin Resource Management through access to a significant pool of management expertise and established relationships throughout the energy industry. We do not have employees. Martin Resource Management employees are responsible for conducting our business and operating our

assets on our behalf.

Related Party Agreements

The Omnibus Agreement with Martin Resource Management requires us to reimburse Martin Resource Management for all direct expenses it incurs or payments it makes on our behalf or in connection with the operation of our business. We reimbursed Martin Resource Management for $177.1 million, $157.8 million and $142.0 million of direct costs and expenses for the years ended December 31, 2013, 2012 and 2011, respectively. There is no monetary limitation on the amount we are required to reimburse Martin Resource Management for direct expenses.

In addition to the direct expenses, under the Omnibus Agreement, we are required to reimburse Martin Resource Management for indirect general and administrative and corporate overhead expenses. For the years ended December 31, 2013, 2012, and 2011, the conflicts committee of our general partner ("Conflicts Committee") approved reimbursement amounts of $10.6 million, $7.6 million and $4.8 million, respectively, reflecting our allocable share of such expenses. The Conflicts Committee will review and approve future adjustments in the reimbursement amount for indirect expenses, if any, annually. These indirect expenses covered the centralized corporate functions Martin Resource Management provides for us, such as accounting, treasury, clerical, engineering, legal, billing, information technology, administration of insurance, general office expenses and employee benefit plans and other general corporate overhead functions we share with Martin Resource Management's retained businesses. The Omnibus Agreement also contains significant non-compete provisions and indemnity obligations. Martin Resource Management also licenses certain of its trademarks and trade names to us under the Omnibus Agreement.

Other agreements include, but are not limited to, a motor carrier agreement, marine transportation agreements, terminal services agreements, a tolling agreement, a sulfuric acid sales agency agreement and various other miscellaneous agreements. Pursuant to the terms of the Omnibus Agreement, we are prohibited from entering into certain material agreements with Martin Resource Management without the approval of the Conflicts Committee.

For a more comprehensive discussion concerning the Omnibus Agreement and the other agreements that we have entered into with Martin Resource Management, please see "Item 13. Certain Relationships and Related Transactions, and Director Independence – Agreements."

Commercial

We have been and anticipate that we will continue to be both a significant customer and supplier of products and services offered by Martin Resource Management. Our motor carrier agreement with Martin Resource Management provides us with access to Martin Resource Management's fleet of road vehicles and road trailers to provide land transportation in the areas served by Martin Resource Management. Our ability to utilize Martin Resource Management's land transportation operations is currently a key component of our integrated distribution network.

We also use the underground storage facilities owned by Martin Resource Management in our natural gas services operations. We lease an underground storage facility from Martin Resource Management in Arcadia, Louisiana with a storage capacity of 2.2 million barrels. Our use of this storage facility gives us greater flexibility in our operations by allowing us to store a sufficient supply of product during times of decreased demand for use when demand increases.

In the aggregate, our purchases of land transportation services, NGL storage services, lubricants purchases and sulfur services payroll reimbursements from Martin Resource Management accounted for approximately 8% of our total cost of products sold during the years ended December 31, 2013 and 2012, and 2011. We also purchase marine fuel from Martin Resource Management, which we account for as an operating expense.

Correspondingly, Martin Resource Management is one of our significant customers. It primarily uses our terminalling, marine transportation and NGL distribution services for its operations. We provide terminalling and storage services under a terminal services agreement. We provide marine transportation services to Martin Resource Management under a charter agreement on a spot-contract basis at applicable market rates. Our sales to Martin Resource Management accounted for approximately 6% of our total revenues for the years ended December 31, 2013 and 2012 and 7% for 2011. We have entered into certain agreements with Martin Resource Management pursuant to which we provide terminalling and storage and marine transportation services to its subsidiary, MES, and MES provides terminal services to us to handle lubricants, greases and drilling fluids. Additionally, we have entered into a long-term, fee for services-based tolling agreement with Martin Resource Management where Martin Resource Management agrees to pay us for the processing of its crude oil into finished products, including naphthenic lubricants, distillates, asphalt and other intermediate cuts.

For a more comprehensive discussion concerning the Omnibus Agreement and the other agreements that we have entered into with Martin Resource Management, please see “Item 13. Certain Relationships and Related Transactions, and Director Independence – Agreements.”

Approval and Review of Related Party Transactions

If we contemplate entering into a transaction, other than a routine or in the ordinary course of business transaction, in which a related person will have a direct or indirect material interest, the proposed transaction is submitted for consideration to the board of directors of our general partner or to our management, as appropriate. If the board of directors is involved in the

approval process, it determines whether to refer the matter to the Conflicts Committee, as provided under our limited partnership agreement. If a matter is referred to the Conflicts Committee, it obtains information regarding the proposed transaction from management and determines whether to engage independent legal counsel or an independent financial advisor to advise the members of the committee regarding the transaction. If the Conflicts Committee retains such counsel or financial advisor, it considers such advice and, in the case of a financial advisor, such advisor's opinion as to whether the transaction is fair and reasonable to us and to our unitholders.

Insurance

Our deductible for onshore physical damage resulting from named windstorms is 5% of the total value located at an individual location subject to an overall minimum deductible of $4.0 million for damage caused by the named windstorm at all locations. Our onshore program currently provides $30.0 million per occurrence for named windstorm events. For non-windstorm events, our deductible applicable to onshore physical damage is $1.5 million per occurrence. Business interruption coverage in connection with a windstorm event is subject to the same $30.0 million per occurrence and aggregate limit as the property damage coverage and a waiting period of 45 days. For non-windstorm events, our waiting period applicable to business interruption is 30 days.

Our deductible for physical damage at our refining, blending and packaging division in Smackover, Arkansas is $0.5 million per occurrence. The waiting period applicable to business interruption is 30 days.

Loss of, or damage to, our vessels and cargo is insured through hull and cargo insurance policies. Vessel operating liabilities such as collision, cargo, environmental and personal injury are insured primarily through our participation in mutual insurance associations and other reinsurance arrangements, pursuant to which we are potentially exposed to assessments in the event claims by us or other members exceed available funds and reinsurance. Protection and indemnity ("P&I") insurance coverage is provided by P&I associations and other insurance underwriters. Our vessels are entered in P&I associations that are parties to a pooling agreement, known as the International Group Pooling Agreement ("Pooling Agreement") through which approximately 90% of the world's ocean-going tonnage is reinsured through a group reinsurance policy. With regard to collision coverage, the first $1.0 million of coverage is insured by our hull policy and any excess is insured by a P&I association. We insure our owned cargo through a domestic insurance company. We insure cargo owned by third parties through our P&I coverage. As a member of P&I associations that are parties to the Pooling Agreement, we are subject to supplemental calls payable to the associations of which we are a member, based on our claims record and the other members of the other P&I associations that are parties to the Pooling Agreement. Except for our marine operations, we self-insure against liability exposure up to a pre-determined amount, beyond which we are covered by catastrophe insurance coverage.

For marine claims, our insurance covers up to $1.0 billion of liability per accident or occurrence. We believe our current insurance coverage is adequate to protect us against most accident related risks involved in the conduct of our business. However, there can be no assurance that all risks are adequately insured against, that any particular claim will be paid by the insurer, or that we will be able to procure adequate insurance coverage at commercially reasonable rates in the future.

Environmental and Regulatory Matters

Our activities are subject to various federal, state and local laws and regulations, as well as orders of regulatory bodies, governing a wide variety of matters, including marketing, production, pricing, community right-to-know, protection of the environment, safety and other matters.

Environmental

We are subject to complex federal, state, and local environmental laws and regulations governing the discharge of materials into the environment or otherwise relating to protection of human health, natural resources and the environment. 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 we 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. Many environmental laws and regulations can impose joint and several, strict liability, and any failure to comply with environmental laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of investigatory and remedial obligations, and, in some circumstances, the issuance of injunctions that can limit or prohibit our operations.

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, there is inherent risk of incurring significant environmental costs and liabilities in the performance of our operations due to our handling of petroleum products and by-products, chemical substances, and wastes as well as the accidental release or spill of such materials into the environment. Consequently, we cannot assure you that we will not incur significant costs and liabilities as result of such handling practices, releases or spills, 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 current environmental laws and regulations and that continued compliance with existing requirements would not have a material adverse impact on us, we cannot provide any assurance that our environmental compliance expenditures will not have a material adverse impact on us in the future.

Superfund

The Federal Comprehensive Environmental Response, Compensation and Liability Act, as amended, ("CERCLA"), also known as the "Superfund" law, and similar state laws, impose liability without regard to fault or the legality of the original conduct, on certain classes of "responsible persons," including the owner or operator of a site where regulated hazardous substances have been released into the environment and companies that disposed or arranged for the disposal of the hazardous substances found at such site. 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, and 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. Although certain hydrocarbons are not subject to CERCLA's reach because "petroleum" is excluded from CERCLA's definition of a "hazardous substance," in the course of our ordinary operations we will generate wastes that may fall within the definition of a "hazardous substance." We are not subject to any notification that we may be potentially responsible for cleanup costs under CERCLA.

Solid Waste

We generate both hazardous and nonhazardous solid wastes, which are subject to requirements of the federal Resource Conservation and Recovery Act, as amended ("RCRA") and comparable state statutes. From time to time, the U.S. Environmental Protection Agency ("EPA") has considered making changes in nonhazardous waste standards that would result in stricter disposal requirements for these wastes. Furthermore, it is possible some wastes generated by us that are currently classified as nonhazardous may in the future be designated as "hazardous wastes," resulting in the wastes being subject to more rigorous and costly disposal requirements. Changes in applicable regulations may result in an increase in our capital expenditures or operating expenses.

We currently own or lease, and have in the past owned or leased, properties that have been used for the manufacturing, processing, transportation and storage of petroleum products and by-products. Solid waste disposal practices within oil and gas related industries have improved over the years with the passage and implementation of various environmental laws and regulations. Nevertheless, a possibility exists that petroleum and other solid wastes may have been disposed of on or under various properties owned or leased by us during the operating history of those facilities. In addition, a number of these properties have been operated by third parties over whom we had no control as to such entities' handling of petroleum, petroleum by-products or other wastes and the manner in which such substances may have been disposed of or released. State and federal laws and regulations applicable to oil and natural gas wastes and properties have gradually become more strict and, under such laws and regulations, we could be required to remove or remediate previously disposed wastes or property contamination, including groundwater contamination, even under circumstances where such contamination resulted from past operations of third parties.

Clean Air Act

Our operations are subject to the federal Clean Air Act ("CAA"), as amended, and comparable state statutes. Amendments to the CAA adopted in 1990 contain provisions that may result in the imposition of increasingly stringent pollution control requirements with respect to air emissions from the operations of our terminal facilities, processing and storage facilities and fertilizer and related products manufacturing and processing facilities. Such air pollution control requirements may include specific equipment or technologies to control emissions, permits with emissions and operational limitations, pre-approval of new or modified projects or facilities producing air emissions, and similar measures. For example, the Neches Terminal is located in an EPA-designated ozone non-attainment area, referred to as the Beaumont/Port Arthur non-attainment area, which is subject to a EPA-adopted 8-hour standard for complying with the national standard for ozone. In

addition, existing sources of air emissions in the Beaumont/Port Arthur area are already subject to stringent emission reduction requirements. Failure to comply with applicable air statutes or regulations may lead to the assessment of administrative, civil or criminal penalties, and/or result in the limitation or cessation of construction or operation of certain air emission sources. We believe our operations, including our manufacturing, processing and storage facilities and terminals, are in substantial compliance with applicable requirements of the CAA and analogous state laws.

Global Warming and Climate Change. Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" and including carbon dioxide and methane, may be contributing to warming of the Earth's atmosphere. In response to such studies, the U.S. Congress has from time to time considered climate change-related legislation to restrict greenhouse gas emissions. At least 17 states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Also, as a result of the U.S. Supreme Court's decision on April 2, 2007, in Massachusetts, et al. v. EPA, the EPA eventually concluded that it is required to regulate greenhouse gas emissions from mobile sources (e.g., cars and trucks) even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The Court's holding in Massachusetts that greenhouse gases fall under the federal CAA's definition of air pollutant has also led the EPA to determine that regulation of greenhouse gas emissions from stationary sources under various Clean Air Act programs is required. To that end, EPA promulgated regulations, referred to as the Tailoring Rule, 75 Fed. Red. 31514, to begin gradually subjecting stationary greenhouse gas emission sources to various Clean Air Act programs, including permitting programs applicable to new and existing major sources of greenhouse gas emissions. To date, such requirements have not had a substantial effect upon our operations. Still, new legislation or regulatory programs that restrict emissions of greenhouse gases in areas in which we conduct business could adversely affect our operations and demand for our services.

Clean Water Act

The Federal Water Pollution Control Act, as amended, also known as the Clean Water Act, and analogous state laws impose restrictions and controls on the discharge of pollutants into federal and state waters. Regulations promulgated under these laws require entities that discharge into federal and state waters obtain National Pollutant Discharge Elimination System ("NPDES") and/or state permits authorizing these discharges. The Clean Water Act and analogous state laws assess penalties for releases of unauthorized pollutants into the water and impose substantial liability for the costs of removing spills from such waters. In addition, the Clean Water Act and analogous state laws require that individual permits or coverage under general permits be obtained by covered facilities for discharges of storm water runoff and that applicable facilities develop and implement plans for the management of storm water runoff (referred to as storm water pollution prevention plans ("SWPPPs")) as well as for the prevention and control of oil spills (referred to as spill prevention, control and countermeasure ("SPCC") plans). As part of the regular overall evaluation of our on-going operations, we are reviewing and, as necessary, updating SWPPPs for certain of our facilities, including facilities recently acquired. In addition, we have reviewed our SPCC plans and, where necessary, amended such plans to comply with applicable regulations adopted by the EPA. We believe that compliance with the conditions of such permits and plans will not have a material effect on our operations.

Oil Pollution Act

The Oil Pollution Act of 1990, as amended ("OPA") imposes a variety of regulations on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in U.S. waters. A "responsible party" includes the owner or operator of a facility or vessel or the lessee or permittee of the area in which an offshore facility is located. The OPA assigns liability to each responsible party for oil removal costs and a variety of public and private damages including natural resource damages. Under the OPA, vessels and shore facilities handling, storing, or transporting oil are required to develop and implement oil spill response plans, and vessels greater than 300 tons in weight must provide to the U.S. Coast Guard evidence of financial responsibility to cover the costs of cleaning up oil

spills from such vessels. The OPA also requires that all newly constructed tank barges engaged in oil transportation in the U.S. be double hulled and all existing single hull tank barges be retrofitted with double hulls or phased out by 2015. We believe we are in substantial compliance with all of the oil spill-related and financial responsibility requirements. Nonetheless, in the aftermath of the Deepwater Horizon incident in 2010, Congress has from time to time considered oil spill related legislation that could have the effect of substantially increasing financial responsibility requirements and potential fines and damages for violations and discharges subject to the OPA, and similar legislation. Any such changes in law affecting areas where we conduct business could materially affect our operations.

Safety Regulation

The Company’s marine transportation operations are subject to regulation by the U.S. Coast Guard, federal laws, state laws and certain international treaties. Tank ships, push boats, tugboats and barges are required to meet construction and repair

standards established by the American Bureau of Shipping, a private organization, and the U.S. Coast Guard and to meet operational and safety standards presently established by the U.S. Coast Guard. We believe our marine operations and our terminals are in substantial compliance with current applicable safety requirements.

Occupational Health Regulations

The workplaces associated with our manufacturing, processing, terminal and storage facilities are subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes. We believe we have conducted our operations in substantial compliance with OSHA requirements, including general industry standards, record keeping requirements and monitoring of occupational exposure to regulated substances. Our marine vessel operations are also subject to safety and operational standards established and monitored by the U.S. Coast Guard.

In general, we expect to increase our expenditures relating to compliance with likely higher industry and regulatory safety standards such as those described above. These expenditures cannot be accurately estimated at this time, but we do not expect them to have a material adverse effect on our business.

Jones Act

The Jones Act is a federal law that restricts maritime transportation between locations in the U.S. to vessels built and registered in the U.S. and owned and manned by U.S. citizens. Since we engage in maritime transportation between locations in the U.S., we are subject to the provisions of the law. As a result, we are responsible for monitoring the ownership of our subsidiaries that engage in maritime transportation and for taking any remedial action necessary to ensure that no violation of the Jones Act ownership restrictions occurs. The Jones Act also requires that all U.S.-flagged vessels be manned by U.S. citizens. Foreign-flagged seamen generally receive lower wages and benefits than those received by U.S. citizen seamen. This requirement significantly increases operating costs of U.S.-flagged vessel operations compared to foreign-flagged vessel operations. Certain foreign governments subsidize their nations' shipyards. This results in lower shipyard costs both for new vessels and repairs than those paid by U.S.-flagged vessel owners. The U.S. Coast Guard and American Bureau of Shipping maintain the most stringent regimen of vessel inspection in the world, which tends to result in higher regulatory compliance costs for U.S.-flagged operators than for owners of vessels registered under foreign flags of convenience.

Merchant Marine Act of 1936

The Merchant Marine Act of 1936 is a federal law that provides that, upon proclamation by the President of the U.S. of a national emergency or a threat to the national security, the U.S. Secretary of Transportation may requisition or purchase any vessel or other watercraft owned by U.S. citizens (including us, provided that we are considered a U.S. citizen for this purpose). If one of our push boats, tugboats or tank barges were purchased or requisitioned by the U.S. government under this law, we would be entitled to be paid the fair market value of the vessel in the case of a purchase or, in the case of a requisition, the fair market value of charter hire. However, if one of our push boats or tugboats is requisitioned or purchased and its associated tank barge is left idle, we would not be entitled to receive any compensation for the lost revenues resulting from the idled barge. We also would not be entitled to be compensated for any consequential damages we suffer as a result of the requisition or purchase of any of our push boats, tugboats or tank barges.

Employees

We do not have any employees. Under our Omnibus Agreement with Martin Resource Management, Martin Resource Management provides us with corporate staff and support services. These services include centralized corporate functions, such as accounting, treasury, engineering, information technology, insurance, administration of

employee benefit plans and other corporate services. Martin Resource Management employs approximately 799 individuals including 52 employees represented by labor unions who provide direct support to our operations as of December 31, 2013.

Financial Information about Segments

Information regarding our operating revenues and identifiable assets attributable to each of our segments is presented in Note 20 to our consolidated financial statements included in this annual report on Form 10-K.

Access to Public Filings

We provide public access to our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to these reports filed with the SEC under the Securities and Exchange Act of 1934. These

documents may be accessed free of charge on our website at the following address: www.martinmidstream.com. These documents are provided as soon as is reasonably practicable after their filing with the SEC. This website address is intended to be an inactive, textual reference only, and none of the material on this website is part of this report. These documents may also be found at the SEC's website at www.sec.gov.

Item 1A. Risk Factors

Limited partner interests are inherently different from the capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a business similar to ours. If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected. In this case, we might not be able to pay distributions on our common units, the trading price of our common units could decline and unitholders could lose all or part of their investment. These risk factors should be read in conjunction with the other detailed information concerning us set forth herein.

Risks Relating to Our Business

Important factors that could cause actual results to differ materially from our expectations include, but are not limited to, the risks set forth below. The risks described below should not be considered to be comprehensive and all-inclusive. Many of such factors are beyond our ability to control or predict. Unitholders are cautioned not to put undue reliance on forward-looking statements. Additional risks that we do not yet know of or that we currently think are immaterial may also impair our business operations, financial condition and results of operations.

We may not have sufficient cash after the establishment of cash reserves and payment of our general partner's expenses to enable us to pay the minimum quarterly distribution each quarter.

We may not have sufficient available cash each quarter in the future to pay the minimum quarterly distribution on all our units. Under the terms of our partnership agreement, we must pay our general partner's expenses and set aside any cash reserve amounts before making a distribution to our unitholders. The amount of cash we can distribute on our common units principally depends upon the amount of net cash generated from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the costs of acquisitions, if any;
- the prices of petroleum products and by-products;
- fluctuations in our working capital;
- the level of capital expenditures we make;
- restrictions contained in our debt instruments and our debt service requirements;
- our ability to make working capital borrowings under our credit facility; and
- the amount, if any, of cash reserves established by our general partner in its discretion.

Unitholders should also be aware that the amount of cash we have available for distribution depends primarily on our cash flow, including cash flow from working capital borrowings, and not solely on profitability, which will be affected by non-cash items. In addition, our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, issuances of additional partnership securities and the establishment of

reserves, each of which can affect the amount of cash available for distribution to our unitholders. As a result, we may make cash distributions during periods when we record losses and may not make cash distributions during periods when we record net income.

Restrictions in our credit facility may prevent us from making distributions to our unitholders.

The payment of principal and interest on our indebtedness reduces the cash available for distribution to our unitholders. In addition, we are prohibited by our credit facility from making cash distributions during a default or an event of default under our credit facility or if the payment of a distribution would cause a default or an event of default thereunder. Our leverage and various limitations in our credit facility may reduce our ability to incur additional debt, engage in certain

transactions, and capitalize on acquisition or other business opportunities that could increase cash flows and distributions to our unitholders.

Debt we owe or incur in the future may limit our flexibility to obtain financing and to pursue other business opportunities.

Our indebtedness could have important consequences, 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;
- our funds available for operations, future business opportunities and distributions to unitholders will be reduced by that portion of our cash flows required to make interest payments on the debt;
- we may be more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- our flexibility in responding to changing business and economic conditions may be limited.

Our ability to service our debt 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 any future indebtedness, we will be forced to take actions such as reducing distributions, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets or seeking additional equity capital. We may not be able to effect any of these actions on satisfactory terms or at all.

If we do not have sufficient capital resources for acquisitions or opportunities for expansion, our growth will be limited.

We intend to explore acquisition opportunities in order to expand our operations and increase our profitability. We may finance acquisitions through public and private financing, or we may use our limited partner interests for all or a portion of the consideration to be paid in acquisitions. Distributions of cash with respect to these equity securities or limited partner interests may reduce the amount of cash available for distribution to the common units. In addition, in the event our limited partner interests do not maintain a sufficient valuation, or potential acquisition candidates are unwilling to accept our limited partner interests as all or part of the consideration, we may be required to use our cash resources, if available, or rely on other financing arrangements to pursue acquisitions. If we use funds from operations, other cash resources or increased borrowings for an acquisition, the acquisition could adversely impact our ability to make our minimum quarterly distributions to our unitholders. Additionally, if we do not have sufficient capital resources or are not able to obtain financing on terms acceptable to us for acquisitions, our ability to implement our growth strategies may be adversely impacted.

We are exposed to counterparty risk in our credit facility and related interest rate protection agreements.

We rely on our credit facility to assist in financing a significant portion of our working capital, acquisitions and capital expenditures. Our ability to borrow under our credit facility may be impaired because:

- one or more of our lenders may be unable or otherwise fail to meet its funding obligations;
- the lenders do not have to provide funding if there is a default under the credit facility or if any of the representations or warranties included in the credit facility are false in any material respect; and

- if any lender refuses to fund its commitment for any reason, whether or not valid, the other lenders are not required to provide additional funding to make up for the unfunded portion.

If we are unable to access funds under our credit facility, we will need to meet our capital requirements, including some of our short-term capital requirements, using other sources. Alternative sources of liquidity may not be available on acceptable terms, if at all. If the cash generated from our operations or the funds we are able to obtain under our credit facility or other sources of liquidity are not sufficient to meet our capital requirements, then we may need to delay or abandon capital projects or other business opportunities, which could have a material adverse effect on our business, financial condition and results of operations.

In addition, we have from time to time entered into interest rate protection agreements to manage our interest rate risk exposure by fixing a portion of the interest expense we pay on our long-term debt under our credit facility. Uncertainty in the global economy and banking markets exists, which could affect whether the counterparties to such interest rate protection agreements are able to honor their agreements. If the counterparties fail to honor their commitments, we could experience higher interest rates, which could have a material adverse effect on our business, financial condition and results of operations. In addition, if the counterparties fail to honor their commitments, we also may be required to replace such interest rate protection agreements with new interest rate protection agreements, and such replacement interest rate protection agreements may be at higher rates than our current interest rate protection agreements, which could have a material adverse effect on our business, financial condition and results of operations.

The impacts of climate-related initiatives at the international, federal and state levels remain uncertain at this time.

Currently, there are numerous international, federal and state-level initiatives and proposals addressing domestic and global climate issues. Within the U.S., most of these proposals would regulate and/or tax, in one fashion or another, the production of carbon dioxide and other "greenhouse gases" to facilitate the reduction of carbon compound emissions to the atmosphere and provide tax and other incentives to produce and use more "clean energy."

Our recent and future acquisitions may not be successful, may substantially increase our indebtedness and contingent liabilities and may create integration difficulties.

As part of our business strategy, we intend to acquire businesses or assets we believe complement our existing operations. We may not be able to successfully integrate recent or any future acquisitions into our existing operations or achieve the desired profitability from such acquisitions. These acquisitions may require substantial capital expenditures and the incurrence of additional indebtedness. If we make acquisitions, our capitalization and results of operations may change significantly. Further, any acquisition could result in:

- post-closing discovery of material undisclosed liabilities of the acquired business or assets;
- the unexpected loss of key employees or customers from the acquired businesses;
- difficulties resulting from our integration of the operations, systems and management of the acquired business; and
- an unexpected diversion of our management's attention from other operations.

If recent or any future acquisitions are unsuccessful or result in unanticipated events or if we are unable to successfully integrate acquisitions into our existing operations, such acquisitions could adversely affect our results of operations, cash flow and ability to make distributions to our unitholders.

Adverse weather conditions, including droughts, hurricanes, tropical storms and other severe weather, could reduce our results of operations and ability to make distributions to our unitholders.

Our distribution network and operations are primarily concentrated in the Gulf Coast region and along the Mississippi River inland waterway. Weather in these regions is sometimes severe (including tropical storms and hurricanes) and can be a major factor in our day-to-day operations. Our marine transportation operations can be significantly delayed, impaired or postponed by adverse weather conditions, such as fog in the winter and spring months and certain river conditions. Additionally, our marine transportation operations and our assets in the Gulf of Mexico, including our barges, push boats, tugboats and terminals, can be adversely impacted or damaged by hurricanes, tropical storms, tidal waves or other related events. Demand for our lubricants and the diesel fuel we throughput in our Terminalling and Storage segment can be affected if offshore drilling operations are disrupted by weather in the Gulf of Mexico.

National weather conditions have a substantial impact on the demand for our products. Unusually warm weather during the winter months can cause a significant decrease in the demand for NGL products. Likewise, extreme weather conditions (either wet or dry) can decrease the demand for fertilizer. For example, an unusually wet spring can delay planting of seeds, which can leave insufficient time to apply fertilizer at the planting stage. Conversely, drought conditions can kill or severely stunt the growth of crops, thus eliminating the need to nurture plants with fertilizer. Any of these or similar conditions could result in a decline in our net income and cash flow, which would reduce our ability to make distributions to our unitholders.

If we incur material liabilities that are not fully covered by insurance, such as liabilities resulting from accidents on rivers or at sea, spills, fires or explosions, our results of operations and ability to make distributions to our unitholders could be adversely affected.

Our operations are subject to the operating hazards and risks incidental to terminalling and storage, marine transportation and the distribution of petroleum products and by-products and other industrial products. These hazards and risks, many of which are beyond our control, include:

- accidents on rivers or at sea and other hazards that could result in releases, spills and other environmental damages, personal injuries, loss of life and suspension of operations;
- leakage of NGLs and other petroleum products and by-products;
- fires and explosions;
- damage to transportation, terminalling and storage facilities and surrounding properties caused by natural disasters; and
- terrorist attacks or sabotage.

Our insurance coverage may not be adequate to protect us from all material expenses related to potential future claims for personal-injury and property damage, including various legal proceedings and litigation resulting from these hazards and risks. If we incur material liabilities that are not covered by insurance, our operating results, cash flow and ability to make distributions to our unitholders could be adversely affected.

Changes in the insurance markets attributable to the effects of Hurricanes Katrina, Rita and Ike and their aftermath may make some types of insurance more difficult or expensive for us to obtain. As a result, we may be unable to secure the levels and types of insurance we would otherwise have secured prior to such events. Moreover, the insurance that may be available to us may be significantly more expensive than our existing insurance coverage.

The price volatility of petroleum products and by-products could reduce our liquidity and results of operations and ability to make distributions to our unitholders.

We purchase petroleum products and by-products, such as molten sulfur, sulfur derivatives, fuel oils, NGLs, lubricants, asphalt and other bulk liquids and sell these products to wholesale and bulk customers and to other end users. We also generate revenues through the terminalling and storage of certain products for third parties. The price and market value of petroleum products and by-products could be, and has recently been, volatile. Our liquidity and revenues have been adversely affected by this volatility during periods of decreasing prices because of the reduction in the value and resale price of our inventory. In addition, our liquidity and costs have been adversely affected during periods of increasing prices because of the increased costs associated with our purchase of petroleum products and by-products. Future price volatility could have an adverse impact on our liquidity and results of operations, cash flow and ability to make distributions to our unitholders.

Increasing energy prices could adversely affect our results of operations.

Increasing energy prices could adversely affect our results of operations. Diesel fuel, natural gas, chemicals and other supplies are recorded in operating expenses. An increase in price of these products would increase our operating expenses, which could adversely affect our results of operations including net income and cash flows. We cannot assure unitholders that we will be able to pass along increased operating expenses to our customers.

Increased competition from alternative natural gas transportation and storage options and alternative fuel sources could have a significant financial impact on us.

Our ability to renew or replace existing contracts at rates sufficient to maintain current revenues and cash flows could be adversely affected by activities of other interstate and intrastate pipelines and storage facilities that may expand or construct competing transportation and storage systems. In addition, future pipeline transportation and storage capacity could be constructed in excess of actual demand and with lower fuel requirements, operating and maintenance costs than our facilities, which could reduce the demand for and the rates that we receive for our services in particular areas. Further, natural gas also competes with alternative energy sources available to our customers that are used to generate electricity, such as hydroelectric power, solar, wind, nuclear, coal and fuel oil.

Demand for a portion of our terminalling and storage services is substantially dependent on the level of offshore oil and gas exploration, development and production activity.

The level of offshore oil and gas exploration, development and production activity historically has been volatile and is likely to continue to be so in the future. The level of activity is subject to large fluctuations in response to relatively minor changes in a variety of factors that are beyond our control, including:

- prevailing oil and natural gas prices and expectations about future prices and price volatility;
- the cost of offshore exploration for and production and transportation of oil and natural gas;
- worldwide demand for oil and natural gas;
- consolidation of oil and gas and oil service companies operating offshore;
- availability and rate of discovery of new oil and natural gas reserves in offshore areas;
- local and international political and economic conditions and policies;
- technological advances affecting energy production and consumption;
- weather conditions;
- environmental regulation; and
- the ability of oil and gas companies to generate or otherwise obtain funds for exploration and production.

We expect levels of offshore oil and gas exploration, development and production activity to continue to be volatile and affect demand for our terminalling and storage services.

Our NGL and sulfur-based fertilizer products are subject to seasonal demand and could cause our revenues to vary.

The demand for NGLs and natural gas is highest in the winter. Therefore, revenue from our natural gas services business is higher in the winter than in other seasons. Our sulfur-based fertilizer products experience an increase in demand during the spring, which increases the revenue generated by this business line in this period compared to other periods. The seasonality of the revenue from these products may cause our results of operations to vary on a quarter-to-quarter basis and thus could cause our cash available for quarterly distributions to fluctuate from period to period.

The highly competitive nature of our industry could adversely affect our results of operations and ability to make distributions to our unitholders.

We operate in a highly competitive marketplace in each of our primary business segments. Most of our competitors in each segment are larger companies with greater financial and other resources than we possess. We may lose customers and future business opportunities to our competitors and any such losses could adversely affect our results of operations and ability to make distributions to our unitholders.

Our business is subject to compliance with environmental laws and regulations that may expose us to significant costs and liabilities and adversely affect our results of operations and ability to make distributions to our unitholders.

Our business is subject to federal, state and local environmental laws and regulations governing the discharge of materials into the environment or otherwise relating to protection of human health, natural resources and the environment. These laws and regulations may impose numerous obligations that are applicable to our operations, such: as requiring the acquisition of permits to conduct regulated activities; restricting the manner in which we 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. Numerous governmental authorities, such as the U.S. Environmental Protection Agency and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly actions. Many environmental laws and regulations can impose joint and several strict liability, and any failure to comply with environmental laws, regulations and

permits may result in the assessment of administrative, civil and criminal penalties, the imposition of investigatory and remedial obligations and, in some circumstances, the issuance of injunctions that can limit or prohibit our operations. 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.

The loss or insufficient attention of key personnel could negatively impact our results of operations and ability to make distributions to our unitholders.

Our success is largely dependent upon the continued services of members of the senior management team of Martin Resource Management. Those senior officers have significant experience in our businesses and have developed strong relationships with a broad range of industry participants. The loss of any of these executives could have a material adverse effect on our relationships with these industry participants, our results of operations and our ability to make distributions to our unitholders.

We do not have employees. We rely solely on officers and employees of Martin Resource Management to operate and manage our business. Martin Resource Management operates businesses and conducts activities of its own in which we have no economic interest. There could be competition for the time and effort of the officers and employees who provide services to our general partner. If these officers and employees do not or cannot devote sufficient attention to the management and operation of our business, our results of operations and ability to make distributions to our unitholders may be reduced.

Our loss of significant commercial relationships with Martin Resource Management could adversely impact our results of operations and ability to make distributions to our unitholders.

Martin Resource Management provides us with various services and products pursuant to various commercial contracts. The loss of any of these services and products provided by Martin Resource Management could have a material adverse impact on our results of operations, cash flow and ability to make distributions to our unitholders. Additionally, we provide terminalling and storage, processing and marine transportation services to Martin Resource Management to support its businesses under various commercial contracts. The loss of Martin Resource Management as a customer could have a material adverse impact on our results of operations, cash flow and ability to make distributions to our unitholders.

Our business would be adversely affected if operations at our transportation, terminalling and storage and distribution facilities experienced significant interruptions. Our business would also be adversely affected if the operations of our customers and suppliers experienced significant interruptions.

Our operations are dependent upon our terminalling and storage facilities and various means of transportation. We are also dependent upon the uninterrupted operations of certain facilities owned or operated by our suppliers and customers. Any significant interruption at these facilities or inability to transport products to or from these facilities or to or from our customers for any reason would adversely affect our results of operations, cash flow and ability to make distributions to our unitholders. Operations at our facilities and at the facilities owned or operated by our suppliers and customers could be partially or completely shut down, temporarily or permanently, as the result of any number of circumstances that are not within our control, such as:

- catastrophic events, including hurricanes;

- environmental remediation;

- labor difficulties; and

- disruptions in the supply of our products to our facilities or means of transportation.

Additionally, terrorist attacks and acts of sabotage could target oil and gas production facilities, refineries, processing plants, terminals and other infrastructure facilities. Any significant interruptions at our facilities, facilities owned or operated by our suppliers or customers, or in the oil and gas industry as a whole caused by such attacks or acts could have a material adverse effect on our results of operations, cash flow and ability to make distributions to our unitholders.

Political, regulatory and economic factors may significantly affect our operations, the manner in which we conduct our business and slow our rate of growth.

Due to changes in the political climate as a result of the outcome of recent state elections and the Congressional election in the U.S., we cannot predict with any certainty the nature and extent of the changes in federal, state and local laws, regulations and policy we will face, or the effect of such elections on any pending legislation. Any increased regulation, new policy initiatives, increased taxes or any other changes in federal law may have an adverse effect on our business, financial condition and results of operations.

NASDAQ does not require a publicly traded partnership like us to comply with certain of its corporate governance requirements.

Because we are a publicly traded partnership, NASDAQ does not require our general partner to have a majority of independent directors on its board of directors or to establish a compensation committee or nominating and corporate governance committee. Accordingly, unitholders do not have the same protections afforded to certain corporations that are subject to all of NASDAQ corporate governance requirements.

Our marine transportation business would be adversely affected if we do not satisfy the requirements of the Jones Act or if the Jones Act were modified or eliminated.

The Jones Act is a federal law that restricts domestic marine transportation in the U.S. to vessels built and registered in the U.S. Furthermore, the Jones Act requires that the vessels be manned and owned by U.S. citizens. If we fail to comply with these requirements, our vessels lose their eligibility to engage in coastwise trade within U.S. Domestic waters.

The requirements that our vessels be U.S. built and manned by U.S. citizens, the crewing requirements and material requirements of the Coast Guard and the application of U.S. labor and tax laws significantly increase the costs of U.S. flagged vessels when compared with foreign-flagged vessels. During the past several years, certain interest groups have lobbied Congress to repeal the Jones Act to facilitate foreign flag competition for trades and cargoes reserved for U.S. flagged vessels under the Jones Act and cargo preference laws. If the Jones Act were to be modified to permit foreign competition that would not be subject to the same U.S. government imposed costs, we may need to lower the prices we charge for our services in order to compete with foreign competitors, which would adversely affect our cash flow and ability to make distributions to our unitholders.

Our marine transportation business would be adversely affected if the U.S. Government purchases or requisitions any of our vessels under the Merchant Marine Act.

We are subject to the Merchant Marine Act of 1936, which provides that, upon proclamation by the President of the U.S. of a national emergency or a threat to the national security, the U.S. Secretary of Transportation may requisition or purchase any vessel or other watercraft owned by U.S. citizens (including us, provided that we are considered a U.S. citizen for this purpose). If one of our push boats, tugboats or tank barges were purchased or requisitioned by the U.S. government under this law, we would be entitled to be paid the fair market value of the vessel in the case of a purchase or, in the case of a requisition, the fair market value of charter hire. However, if one of our push boats or tugboats is requisitioned or purchased and its associated tank barge is left idle, we would not be entitled to receive any compensation for the lost revenues resulting from the idled barge. We also would not be entitled to be compensated for any consequential damages we suffer as a result of the requisition or purchase of any of our push boats, tugboats or tank barges. If any of our vessels are purchased or requisitioned for an extended period of time by the U.S. government, such transactions could have a material adverse effect on our results of operations, cash flow and ability to make distributions to our unitholders.

Regulations affecting the domestic tank vessel industry may limit our ability to do business, increase our costs and adversely impact our results of operations and ability to make distributions to our unitholders.

The Oil Pollution Act of 1990 (“OPA”) provides for the phase out of single-hull vessels and the phase-in of the exclusive operation of double-hull tank vessels in U.S. waters for barges that carry petroleum products that are regulated under OPA. Under OPA, substantially all tank vessels that do not have double hulls will be phased out by 2015 and will not be permitted to enter United States ports or trade in U.S. waters. The phase-out dates vary based on the age of the vessel and other factors. All but one of our offshore tank barges are double-hull vessels that have no phase out date. We have one single-hull barge that will be phased out of the petroleum product trade by the year 2015. The phase out of these single-hull vessels in accordance with OPA may require us to make substantial capital expenditures, which could adversely affect our operations and market position and reduce our cash available for distribution.

Our interest rate swap activities may have a material adverse effect on our earnings, profitability, liquidity, cash flows and financial condition.

We enter into interest rate swap agreements from time to time to manage some of our exposure to interest rate volatility. These swap agreements involve risks, such as the risk that counterparties may fail to honor their obligations under these arrangements. In addition, these arrangements may not be effective in reducing our exposure to changes in interest rates. When we use forward-starting interest rate swaps, there is a risk that we will not complete the long-term borrowing against which the swap is intended to hedge. If such events occur, our results of operations may be adversely affected.

The industry in which we operate is highly competitive, and increased competitive pressure could adversely affect our business and operating results.

We compete with similar enterprises in our respective areas of operation. Some of our competitors are large oil, natural gas and petrochemical companies that have greater financial resources and access to supplies of NGLs than we do. In addition, our customers who are significant producers of natural gas may develop their own gathering, processing and transportation systems in lieu of using ours. Likewise, our customers who produce NGLs may develop their own systems to transport NGLs in lieu of using ours. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain current revenues and cash flows could be adversely affected by the activities of our competitors and our customers. All of these competitive pressures could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

Information technology systems present potential targets for cyber security attacks.

We are reliant on technology to improve efficiency in our business. Information technology systems are critical to our operations. These systems could be a potential target for a cyber security attack as they are used to store and process sensitive information regarding our operations, financial position, an information pertaining to our customers and vendors. While we take the utmost precautions, we cannot guarantee safety from all threats and attacks. Any successful breach of security could result in the spread of inaccurate or confidential information, disruption of operations, environmental harm, endangerment of employees, damage to our assets, and increased costs to respond. Any of these instances could have a negative impact on cash flows, litigation status and/or our reputation, which could have a material adverse affect on our business, financial conditions and operations.

If we are deemed an “investment company” under the Investment Company Act of 1940, it would adversely affect the price of our common units and could have a material adverse effect on our business.

Our assets include interests in joint ventures, including a 42.21% interest in Cardinal and 100% of the preferred interests in Martin Energy Trading LLC. These joint venture interests may be deemed to be “investment securities” within the meaning of the Investment Company Act of 1940, or the Investment Company Act. If a sufficient amount of our assets are deemed to be “investment securities” within the meaning of the Investment Company Act, and we are unable to rely on an exemption under the Investment Company Act, we would either have to register as an investment company under the Investment Company Act, obtain exemptive relief from the SEC or modify our organizational structure or our contract rights to fall outside the definition of an investment company. Registering as an investment company could, among other things, materially limit our ability to engage in transactions with affiliates, including the purchase and sale of certain securities or other property to or from our affiliates, restrict our ability to borrow funds or engage in other transactions involving leverage and require us to add additional directors who are independent of us or our affiliates. The occurrence of some or all of these events may have a material adverse effect on our business.

Moreover, treatment of us as an investment company would prevent our qualification as a partnership for federal income tax purposes in which case we would be treated as a corporation for federal income tax purposes, and be

subject to federal income tax at the corporate tax rate, significantly reducing the cash available for distributions. Additionally, distributions to the unitholders would be taxed again as corporate distributions and none of our income, gains, losses or deductions would flow through to the unitholders.

Additionally, as a result of our desire to avoid having to register as an investment company under the Investment Company Act, we may have to forego potential future acquisitions of interests in companies that may be deemed to be investment securities within the meaning of the Investment Company Act or dispose of our current interests in any of our assets that are deemed to be “investment securities.”

Risks Relating to an Investment in the Common Units

Units available for future sales by us or our affiliates could have an adverse impact on the price of our common units or on any trading market that may develop.

Common units will generally be freely transferable without restriction or further registration under the Securities Act, except that any common units held by an "affiliate" of ours may not be resold publicly except in compliance with the registration requirements of the Securities Act or under an exemption under Rule 144 or otherwise.

Our partnership agreement provides that we may issue an unlimited number of limited partner interests of any type without a vote of the unitholders. Our general partner may also cause us to issue an unlimited number of additional common units or other equity securities of equal rank with the common units, without unitholder approval, in a number of circumstances such as:

- the issuance of common units in additional public offerings or in connection with acquisitions that increase cash flow from operations on a pro forma, per unit basis;
- the conversion of subordinated units into common units;
- the conversion of units of equal rank with the common units into common units under some circumstances; or
- the conversion of our general partner's general partner interest in us and its incentive distribution rights into common units as a result of the withdrawal of our general partner.

Our partnership agreement does not restrict our ability to issue equity securities ranking junior to the common units at any time. Any issuance of additional common units or other equity securities would result in a corresponding decrease in the proportionate ownership interest in us represented by, and could adversely affect the cash distributions to and market price of, common units then outstanding.

Under our partnership agreement, our general partner and its affiliates have the right to cause us to register under the Securities Act and applicable state securities laws the offer and sale of any units that they hold. Subject to the terms and conditions of our partnership agreement, these registration rights allow the general partner and its affiliates or their assignees holding any units to require registration of any of these units and to include any of these units in a registration by us of other units, including units offered by us or by any unitholder. Our general partner will continue to have these registration rights for two years following its withdrawal or removal as a general partner. In connection with any registration of this kind, we will indemnify each unitholder participating in the registration and its officers, directors, and controlling persons from and against any liabilities under the Securities Act or any applicable state securities laws arising from the registration statement or prospectus. Except as described below, the general partner and its affiliates may sell their units in private transactions at any time, subject to compliance with applicable laws. Our general partner and its affiliates, with our concurrence, have granted comparable registration rights to their bank group to which their partnership units have been pledged.

The sale of any common or subordinated units could have an adverse impact on the price of the common units or on any trading market that may develop.

Unitholders have less power to elect or remove management of our general partner than holders of common stock in a corporation. It is unlikely that our common unitholders will have sufficient voting power to elect or remove our general partner without the consent of Martin Resource Management and its affiliates.

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 did not elect our general partner or its directors and will have no right to elect our general partner or its directors on an annual or other continuing basis. Martin Resource Management elects the directors of our general partner. Although our general partner has a fiduciary duty to manage our partnership in a manner beneficial to us and our unitholders, the directors of our general partner also have a fiduciary duty to manage our general partner in a manner beneficial to Martin Resource Management and its shareholders.

If unitholders are dissatisfied with the performance of our general partner, they will have a limited ability to remove our general partner. Our general partner generally may not be removed except upon the vote of the holders of at least 66 2/3%

of the outstanding units voting together as a single class. As of December 31, 2013, Martin Resource Management owned 19.1% of our total outstanding common limited partner units.

Unitholders' voting rights are further restricted by our partnership agreement provision prohibiting any units held by a person owning 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 our general partner's directors, from voting on any matter. In addition, our partnership agreement 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.

As a result of these provisions, it will be more difficult for a third party to acquire our partnership without first negotiating the acquisition with our general partner. Consequently, it is unlikely the trading price of our common units will ever reflect a takeover premium.

Our general partner's discretion in determining the level of our cash reserves may adversely affect our ability to make cash distributions to our unitholders.

Our partnership agreement requires our general partner to deduct from operating surplus cash reserves it determines in its reasonable discretion to be necessary to fund our future operating expenditures. In addition, our partnership agreement 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 cash reserves will affect the amount of cash available for distribution to our unitholders.

Unitholders may not have limited liability if a court finds that we have not complied with applicable statutes or that unitholder action constitutes control of our business.

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 states. The holder of one of our common units could be held liable in some circumstances for our obligations to the same extent as a general partner if a court were to determine that:

- we had been conducting business in any state without compliance with the applicable limited partnership statute or
- the right or the exercise of the right by our unitholders as a group to remove or replace our general partner, to approve some amendments to our partnership agreement, or to take other action under our partnership agreement constituted participation in the “control” of our business.

Our general partner generally has unlimited liability for our obligations, such as our debts and environmental liabilities, except for our contractual obligations that are expressly made without recourse to our general partner. In addition, under some circumstances, a unitholder may be liable to us for the amount of a distribution for a period of nine years from the date of the distribution.

Our partnership agreement contains provisions that reduce the remedies available to unitholders for actions that might otherwise constitute a breach of fiduciary duty by our general partner.

Our partnership agreement limits the liability and reduces the fiduciary duties of our general partner to the unitholders. Our partnership agreement also restricts the remedies available to unitholders for actions that would otherwise constitute breaches of our general partner's fiduciary duties. For example, our partnership agreement:

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permits our general partner to make a number of decisions in its "sole discretion." 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;

- provides that our general partner is entitled to make other decisions in its "reasonable discretion," which may reduce the obligations to which our general partner would otherwise be held;

- generally provides that affiliated transactions and resolutions of conflicts of interest not involving a required vote of unitholders must be "fair and reasonable" to us and that, in determining whether a transaction or

resolution is “fair and reasonable,” our general partner may consider the interests of all parties involved, including its own; and

- provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for errors of judgment or for any acts or omissions if our general partner and those other persons acted in good faith.

Unitholders are treated as having consented to the various actions contemplated in our partnership agreement and conflicts of interest that might otherwise be considered a breach of fiduciary duties under applicable state law.

We may issue additional common units without unitholder approval, which would dilute unitholder ownership interests.

Our general partner may also cause us to issue an unlimited number of additional common units or other equity securities of equal rank with the common units, without unitholder approval, in a number of circumstances such as:

- the issuance of common units in additional public offerings or in connection with acquisitions that increase cash flow from operations on a pro forma, per unit basis;
- the conversion of subordinated units into common units;
- the conversion of units of equal rank with the common units into common units under some circumstances; or
- the conversion of our general partner's general partner interest in us and its incentive distribution rights into common units as a result of the withdrawal of our general partner.

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.

The issuance of additional common units or other equity securities of equal or senior rank will have the following effects:

- our unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on a per unit basis may decrease;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- the relative voting strength of each previously outstanding unit will diminish;
- the market price of the common units may decline; and
- the ratio of taxable income to distributions may increase.

The control of our general partner may be transferred to a third party and that party could replace our current management team, 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, there is no restriction in our partnership agreement on the ability of the owner of our general partner to transfer its ownership interest in our general partner to a third party. A new owner of our general partner could replace the directors and officers of our general partner with its own designees and control the decisions taken by our general partner.

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

If at any time our general partner and its affiliates own more than 80% of the common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the remaining common units held by unaffiliated persons at a price not less than the then-current market price. As a result, unitholders may be required to sell their common units 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 units. No provision in our partnership agreement, or in any other agreement we have with our general partner or Martin Resource Management, prohibits our general partner or its affiliates from acquiring more than 80% of our common units. For additional information about this call right and unitholders' potential tax liability, please see “Risk Factors - Tax Risks - Tax gain or loss on the disposition of our common units could be different than expected.”

Our common units have a limited trading volume compared to other publicly traded securities.

Our common units are quoted on the Nasdaq Global Select Market (“NASDAQ”) under the symbol “MMLP.” However, daily trading volumes for our common units are, and may continue to be, relatively small compared to many other securities quoted on the NASDAQ. The price of our common units may, therefore, be volatile.

Failure to achieve and maintain effective internal controls in accordance with Section 404 of the Sarbanes-Oxley Act could have a material adverse effect on our unit price.

In order to comply with Section 404 of the Sarbanes-Oxley Act, we periodically document and test our internal control procedures. Section 404 of the Sarbanes-Oxley Act requires annual management assessments of the effectiveness of our internal controls over financial reporting addressing these assessments. During the course of our testing we may identify deficiencies, which we may not be able to address in time to meet the deadline imposed by the Sarbanes-Oxley Act for compliance with the requirements of Section 404. In addition, if we fail to maintain the adequacy of our internal controls, as such standards are modified, supplemented or amended from time to time, we may not be able to ensure that we can conclude on an ongoing basis that we have effective internal controls over financial reporting in accordance with Section 404 of the Sarbanes-Oxley Act. Failure to achieve and maintain an effective internal control environment could have a material adverse effect on the price of our common units.

Risks Relating to Our Relationship with Martin Resource Management

Cash reimbursements due to Martin Resource Management may be substantial and will reduce our cash available for distribution to our unitholders.

Under our Omnibus Agreement with Martin Resource Management, Martin Resource Management provides us with corporate staff and support services on behalf of our general partner that are substantially identical in nature and quality to the services it conducted for our business prior to our formation. The Omnibus Agreement requires us to reimburse Martin Resource Management for the costs and expenses it incurs in rendering these services, including an overhead allocation to us of Martin Resource Management's indirect general and administrative expenses from its corporate allocation pool. These payments may be substantial. Payments to Martin Resource Management will reduce the amount of available cash for distribution to our unitholders.

Martin Resource Management has conflicts of interest and limited fiduciary responsibilities, which may permit it to favor its own interests to the detriment of our unitholders.

As of December 31, 2013, Martin Resource Management owned 19.1% of our total outstanding common limited partner units and a 51% voting interest in Holdings, the sole member of MMGP. MMGP owns a 2% general partnership interest in us and all of our incentive distribution rights. Conflicts of interest may arise between Martin Resource Management and our general partner, on the one hand, and our unitholders, on the other hand. As a result of these conflicts, our general partner may favor its own interests and the interests of Martin Resource Management over

the interests of our unitholders. Potential conflicts of interest between us, Martin Resource Management and our general partner could occur in many of our day-to-day operations including, among others, the following situations:

- Officers of Martin Resource Management who provide services to us also devote significant time to the businesses of Martin Resource Management and are compensated by Martin Resource Management for that time;

- Neither our partnership agreement nor any other agreement requires Martin Resource Management to pursue a business strategy that favors us or utilizes our assets or services. Martin Resource Management's directors

and officers have a fiduciary duty to make these decisions in the best interests of the shareholders of Martin Resource Management without regard to the best interests of the unitholders;

- Martin Resource Management may engage in limited competition with us;

- Our general partner is allowed to take into account the interests of parties other than us, such as Martin Resource Management, in resolving conflicts of interest, which has the effect of reducing its fiduciary duty to our unitholders;

- Under our partnership agreement, our general partner may limit its liability and reduce its fiduciary duties, while also restricting the remedies available to our unitholders for actions that, without the limitations and reductions, might constitute breaches of fiduciary duty. As a result of purchasing units, our unitholders will be treated as having consented to some actions and conflicts of interest that, without such consent, might otherwise constitute a breach of fiduciary or other duties under applicable state law;

- Our general partner determines which costs incurred by Martin Resource Management are reimbursable by us;

- Our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered on terms that are fair and reasonable to us or from entering into additional contractual arrangements with any of these entities on our behalf;

- Our general partner controls the enforcement of obligations owed to us by Martin Resource Management;

- Our general partner decides whether to retain separate counsel, accountants or others to perform services for us;

- The audit committee of our general partner retains our independent auditors;

- In some instances, our general partner may cause us to borrow funds to permit us to pay cash distributions, even if the purpose or effect of the borrowing is to make incentive distributions; and

- Our general partner has broad discretion to establish financial reserves for the proper conduct of our business. These reserves also will affect the amount of cash available for distribution.

Martin Resource Management and its affiliates may engage in limited competition with us.

Martin Resource Management and its affiliates may engage in limited competition with us. For a discussion of the non-competition provisions of the Omnibus Agreement, please see “Item 13. Certain Relationships and Related Transactions, and Director Independence.” If Martin Resource Management does engage in competition with us, we may lose customers or business opportunities, which could have an adverse impact on our results of operations, cash flow and ability to make distributions to our unitholders.

If Martin Resource Management were ever to file for bankruptcy or otherwise default on its obligations under its credit facility, amounts we owe under our credit facility may become immediately due and payable and our results of operations could be adversely affected.

If Martin Resource Management were ever to commence or consent to the commencement of a bankruptcy proceeding or otherwise defaults on its obligations under its credit facility, its lenders could foreclose on its pledge of the interests in our general partner and take control of our general partner. If Martin Resources Management no longer controls our general partner, the lenders under our credit facility may declare all amounts outstanding thereunder immediately due and payable. In addition, either a judgment against Martin Resource Management or a bankruptcy filing by or against Martin Resource Management could independently result in an event of default under our credit facility if it could

reasonably be expected to have a material adverse effect on us. If our lenders do declare us in default and accelerate repayment, we may be required to refinance our debt on unfavorable terms, which could negatively impact our results of operations and our ability to make distributions to our unitholders. A bankruptcy filing by or against Martin Resource Management could also result in the termination or material breach of some or all of the various commercial contracts between us and Martin Resource Management, which could have a material adverse impact on our results of operations, cash flow and ability to make distributions to our unitholders.

Tax Risks

The IRS could treat us as a corporation for tax purposes, which would substantially reduce the cash available for distribution to unitholders.

The anticipated after-tax economic benefit of an investment in us depends largely on our classification as a partnership for federal income tax purposes. Despite the fact that we are organized as a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. In order for us to be classified as a partnership for U.S. federal income tax purposes, more than 90% of our gross income each year must be "qualifying income" under Section 7704 of the U.S. Internal Revenue Code of 1986, as amended (the "Internal Revenue Code"). "Qualifying income" includes income and gains derived from the transportation, storage, processing and marketing of crude oil, natural gas and products thereof. Other types of qualifying income include interest (other than from a financial business), dividends, gains from the sale of real property and gains from the sale or other disposition of capital assets held for the production of income that otherwise constitutes qualifying income.

Although we intend to meet this gross income requirement, we may not find it possible, regardless of our efforts, to meet this gross income requirement or may inadvertently fail to meet this gross income requirement. If we do not meet this gross income requirement for any taxable year and the U.S. Internal Revenue Service ("IRS") does not determine that such failure was inadvertent, we would be treated as a corporation for such taxable year and each taxable year thereafter. Moreover, current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. At the federal level, members of Congress have considered substantive changes to the existing U.S. tax laws that would have affected certain publicly traded partnerships. Although the legislation considered would not have appeared to affect our tax treatment, we are unable to predict whether any such change or other proposals will ultimately be enacted. Moreover, any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Any such changes could negatively impact the value of an investment in our common units. At the state level, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, we are required to pay a Texas margin tax at a maximum effective rate of 0.7% of our gross income apportioned to Texas in the prior year. Imposition of any such tax on us by any other state will reduce the cash available for distribution to you.

If we were treated as a corporation for federal income tax purposes, we would owe federal income tax on our income at the corporate tax rate, which is currently a maximum of 35%, and would likely owe state income tax at varying rates. Distributions would generally be taxed again to unitholders as corporate distributions and no income, gains, losses, or deductions would flow through to unitholders. Because a tax would be imposed upon us as an entity, cash available for distribution to unitholders would be reduced. Treatment of us as a corporation would result in a reduction in the anticipated cash flow and after-tax return to unitholders and therefore would likely result in a reduction in the value of the 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 amount will be adjusted to reflect the impact of that law on us.

A successful IRS contest of the federal income tax positions we take may adversely affect the market for our common units and the costs of any contest will be borne by our unitholders, debt security holders and our general partner.

The IRS may adopt positions that differ from our counsel's conclusions. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel's conclusions or the positions we take. A court may not agree with some or all our counsel's conclusions or the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the prices at which they trade. In addition, the costs of any contest with the IRS will be borne directly or indirectly by all of our unitholders, debt security holders and our general partner.

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

Unitholders may be required to pay federal income taxes and, in some cases, state, local and foreign income taxes on their share of our taxable income even if they receive no cash distributions from us. Unitholders may not receive cash distributions from us equal to their share of our taxable income or even the tax liability that results from the taxation of their share of our taxable income.

Tax gain or loss on the disposition of our common units could be different than expected.

If our unitholders sell their common units, they will recognize gain or loss equal to the difference between the amount realized and their tax basis in those common units. Prior distributions in excess of the total net taxable income unitholders were allocated for a common unit, which decreased unitholder tax basis in that common unit, will, in effect, become taxable income to our unitholders if the common unit is sold at a price greater than their tax basis in that common unit, even if the price they receive is less than their original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to our unitholders. Should the IRS successfully contest some positions we take, our unitholders could recognize more gain on the sale of units than would be the case under those positions without the benefit of decreased income in prior years. In addition, if our unitholders sell their units, they may incur a tax liability in excess of the amount of cash they receive from the sale.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, such as employee benefit plans, individual retirement accounts (known as IRAs), Keogh plans and other retirement plans, regulated investment companies, real estate investment trusts, mutual funds and non-U.S. persons raises 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 income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S persons will be required to file U.S. federal income tax returns and pay tax on their share of our taxable income. Tax-exempt entities and non-U.S. persons should consult their tax advisor regarding their investment in our common units.

We treat a purchaser of our common units as having the same tax benefits without regard to the seller's identity. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units and because of other reasons, we have adopted depreciation positions that may not conform to all aspects of the U.S Department of the Treasury's regulations (“Treasury regulations”). Any position we take that is inconsistent with applicable Treasury regulations may have to be disclosed on our federal income tax return. This disclosure increases the likelihood that the IRS will challenge our positions and propose adjustments to some or all of our unitholders. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to our unitholders' tax returns.

Unitholders may be subject to state, local and foreign taxes and return filing requirements as a result of investing in our common units.

In addition to federal income taxes, unitholders may be subject to other taxes, such as state, local and foreign income 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. Unitholders may be required to file state, local and foreign income tax returns and pay state and local income taxes in some or all of the various jurisdictions in which we do business or own property and may be subject to penalties for failure to comply with those requirements. We own property and/or conduct business in Alabama, Arizona, Arkansas, California, Georgia, Florida, Illinois, Louisiana, Minnesota, Mississippi, Missouri, Nebraska, Pennsylvania, Tennessee, Texas and Utah. We may do business or own property in other states or foreign countries in the future. It is the unitholder's responsibility to file all federal, state, local and foreign tax returns. Our counsel has not rendered an opinion on the state, local or foreign tax consequences of an investment in our common units.

There are limits on the deductibility of our losses that may adversely affect our unitholders.

There are a number of limitations that may prevent unitholders from using their allocable share of our losses as a deduction against unrelated income. In cases when our unitholders are subject to the passive loss rules (generally, individuals and closely-held corporations), any losses generated by us will only be available to offset our future income and cannot be used to offset income from other activities, including other passive activities or investments. Unused losses may be deducted when the unitholder disposes of its entire investment in us in a fully taxable transaction with an unrelated party. A unitholder's share of our net passive income may be offset by unused losses from us carried over from prior years but not by losses from other passive activities, including losses from other publicly traded partnerships. Other limitations that may further restrict the deductibility of our losses

by a unitholder include the at-risk rules and the prohibition against loss allocations in excess of the unitholder's tax basis in its units.

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

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible to meet the exception for us to be treated as a partnership for U.S. federal income tax purposes that is not taxable as a corporation (referred to as the “Qualifying Income Exception”), affect or cause us to change our business activities, affect the tax considerations of an investment in us, change the character or treatment of portions of our income and adversely affect an investment in our common units. For example, in response to certain events that occurred in previous years, members of Congress have considered substantive changes to the existing U.S. tax laws including the definition of qualifying income under Section 7704(d) of the Internal Revenue Code and the treatment of certain types of income earned from profits interests in partnerships. Although the legislation considered would not have appeared to affect our tax treatment, we are unable to predict whether any such change or other proposals will ultimately be enacted. Moreover, President Obama has recently urged Congress to consider tax reform pursuant to a Joint Report by The White House and The Department of the Treasury titled The President's Framework for Business Tax Reform released February 2012. Among the President's proposals is to establish greater parity between large corporations and large non-corporate counterparts which could include entity level taxation for publicly traded partnerships, including us. It is possible that these efforts could result in changes to the existing U.S. tax laws that affect publicly traded partnerships, including us. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

The sale or exchange of 50% or more of our capital and profits interests during any 12-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a 12-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns for one fiscal year. For purposes of determining whether the 50% threshold is met, multiple sales of the same units are counted only once. 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 fiscal year ending December 31, the closing of our taxable year may also result in more than 12 months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for 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 recently announced a relief procedure whereby, if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership will be allowed to provide only a single Schedule K-1 to unitholders for the tax year in which the termination occurred.

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

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury regulations. Recently, however, the U.S. Department of the Treasury issued proposed Treasury regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly convention to allocate tax items among transferor and transferee unitholders. Nonetheless, the proposed Treasury regulations do not specifically authorize the use of the proration method we have adopted. Therefore, the use of this proration method may not be permitted under existing Treasury regulations, and, accordingly, our counsel is unable to opine as to the validity of this method. If the IRS were to challenge this 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, he 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.

Because a unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of the loaned units, he may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Our counsel has not rendered an opinion regarding the treatment of a unitholder where common units are loaned to a short seller to cover a short sale of common units; therefore, unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

A description of our properties is contained in “Item 1. Business” and is incorporated herein by reference.

We believe we have satisfactory title to our assets. Some of the easements, rights-of-way, permits, licenses or similar documents relating to the use of the properties that have been transferred to us in connection with our initial public offering and the assets we acquired in our acquisitions, required the consent of third parties, which in some cases is a governmental entity. We believe we have obtained sufficient third-party consents, permits and authorizations for the transfer of assets necessary for us to operate our business in all material respects. With respect to any third-party consents, permits or authorizations that have not been obtained, we believe the failure to obtain these consents, permits or authorizations will not have a material adverse effect on the operation of our business. Title to our property may be subject to encumbrances, including liens in favor of our secured lender. We believe none of these encumbrances materially detract from the value of our properties or our interest in these properties or materially interfere with their use in the operation of our business.

Item 3. Legal Proceedings

From time to time, we are subject to certain legal proceedings, claims and disputes that arise in the ordinary course of our business. Although we cannot predict the outcomes of these legal proceedings, we do not believe these actions, in the aggregate, will have a material adverse impact on our financial position, results of operations or liquidity. A description of our legal proceedings is included in “Item 8. Financial Statements and Supplementary Data, Note 22. Commitments and Contingencies”, and is incorporated herein by reference.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for Our Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities

Our common units are traded on the NASDAQ under the symbol "MMLP." As of March 3, 2014 there were approximately 220 holders of record and approximately 25,400 beneficial owners of our common units. The following table sets forth the high and low sale prices of our common units for the periods indicated, based on the daily composite listing of stock transactions for the NASDAQ and cash distributions declared per common units during those periods:

Fiscal 2013:

	Common Units		Distributions
Quarters Ended	High	Low	Declared per Common Unit
March 31, 2013	$38.52	$31.93	$0.7700
June 30, 2013	$46.20	$37.73	$0.7750
September 30, 2013	$47.02	$42.28	$0.7800
December 31, 2013	$48.53	$40.90	$0.7825

Fiscal 2012:

	Common Units		Distributions
Quarters Ended	High	Low	Declared per Common Unit
March 31, 2012	$37.91	$32.77	$0.7625
June 30, 2012	$35.75	$29.46	$0.7625
September 30, 2012	$35.65	$32.39	$0.7625
December 31, 2012	$36.72	$30.03	$0.7700

On March 3, 2014, the last reported sales price of our common units as reported on the NASDAQ was $42.73 per unit.

In November 2012, in connection with our public offering of 3,450,000 common units, our general partner contributed $2.2 million in cash to us in order to maintain its 2% general partner interest in us.

In January 2012, in connection with our public offering of 2,645,000 common units, our general partner contributed $2.0 million in cash to us in order to maintain its 2% general partner interest in us.

Within 45 days after the end of each quarter, we distribute all of our available cash, as defined in our partnership agreement, to unitholders of record on the applicable record date. Our general partner has broad discretion to establish cash reserves that it determines are necessary or appropriate to properly conduct our business. These can include cash reserves for future capital and maintenance expenditures, reserves to stabilize distributions of cash to the unitholders and our general partner, reserves to reduce debt, or, as necessary, reserves to comply with the terms of any of our agreements or obligations. Our distributions are effectively made 98% to unitholders and 2% to our general partner, subject to the payment of incentive distributions to our general partner if certain target cash distribution levels to common unitholders are achieved. Distributions to our general partner increase to 15%, 25% and 50% based on incremental distribution thresholds as set forth in our partnership agreement. On October 2, 2012, our general partner executed Amendment No. 3 to the Second Amended and Restated Agreement of Limited Partnership of the Partnership ("the Partnership Agreement"). The Partnership Agreement Amendment provides that our general partner, currently the holder of the incentive distribution rights, shall forego the next $18.0 million in incentive distributions that it would otherwise be entitled to receive. As of March 3, 2014, the amount of incentive distributions the general partner has foregone is $11.9 million.

Our ability to distribute available cash is contractually restricted by the terms of our credit facility. Our credit facility contains covenants requiring us to maintain certain financial ratios. We are prohibited from making any distributions to unitholders if the distribution would cause a default or an event of default, or a default or an event of default exists, under our credit facility. Please read "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Description of Our Credit Facility."

Item 6. Selected Financial Data

The following table sets forth selected financial data and other operating data of the Partnership for the years ended December 31, 2013, 2012, 2011, 2010 and 2009 and is derived from the audited consolidated financial statements of the Partnership.

The following selected financial data are qualified by reference to and should be read in conjunction with the Partnership's Consolidated Financial Statements and Notes thereto and “Management’s Discussion and Analysis of Financial Condition and Results of Operations” included elsewhere in this document.

	2013	2012	2011	2010	2009
	(Dollars in thousands, except per unit amounts)				
Income Statement Data:					
Revenues	$1,633,510	$1,490,361	$1,242,490	$880,115	$651,174
Cost of product sold	1,298,324	1,202,264	1,000,923	666,589	449,972
Operating expenses	172,043	146,287	134,734	111,923	111,901
Selling, general, and administrative	29,397	25,494	20,531	16,865	16,005
Depreciation and amortization	52,240	42,063	40,276	36,884	36,183
Total costs and expenses	1,552,004	1,416,108	1,196,464	832,261	614,061
Other operating income (loss)	1,166	(418)	1,326	228	6,025
Operating income	82,672	73,835	47,352	48,082	43,138
Equity in earnings (loss) of unconsolidated entities	(53,048)	(1,113)	(4,752)	2,536	(5,053)
Gain from ownership change in unconsolidated entity	—	—	—	6,413	3,028
Interest expense	(42,495)	(30,665)	(26,781)	(35,322)	(20,357)
Debt prepayment premium	(272)	(2,470)	—	—	—
Other, net	542	1,092	420	385	443
Income (loss) before income taxes	(12,601)	40,679	16,239	22,094	21,199
Income taxes	(753)	(3,557)	(2,872)	(2,622)	(3,524)
Income (loss) from continuing operations	(13,354)	37,122	13,367	19,472	17,675
Income from discontinued operations, net of tax	—	64,865	9,392	8,061	5,268
Net income (loss)	$(13,354)	$101,987	$22,759	$27,533	$22,943
Net income (loss) per limited partner unit – continuing operations	$(0.49)	$1.32	$0.57	$0.25	$0.86
Net income per limited partner unit – discontinued operations	—	2.64	0.35	0.38	0.31
Net income (loss) per limited partner unit	$(0.49)	$3.96	$0.92	$0.63	$1.17
Weighted average limited partner units	26,557,829	23,361,551	19,545,427	17,525,089	14,680,807
Balance Sheet Data (at Period End):					
Total assets	$1,097,919	$1,012,996	$1,069,108	$864,425	$739,161
Due to affiliates	2,596	3,316	74,654	24,578	20,073
Long-term debt	658,695	474,992	458,941	372,862	304,372
Partners' capital	260,417	357,962	337,187	327,960	306,594
Cash Flow Data:					
Net cash flow provided by (used in):					
Operating activities	112,183	32,678	91,362	39,178	48,673
Investing activities	(186,777)	(15,036)	(202,655)	(91,016)	(41,600)
Financing activities	85,974	(12,746)	100,179	57,262	(9,100)
Other Financial Data:					
Maintenance capital expenditures	11,445	9,195	10,947	4,653	7,601

Expansion capital expenditures	87,601	85,549	67,540	14,916	29,653
Total capital expenditures	$99,046	$94,744	$78,487	$19,569	$37,254
Cash dividends per common unit (in dollars)	$3.11	$3.06	$3.05	$3.00	$3.00

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

Overview

We are a publicly traded limited partnership with a diverse set of operations focused primarily in the United States ("U.S.") Gulf Coast region. Our four primary business lines include:

- Terminalling and storage services for petroleum products and by-products including the refining, blending and packaging of finished lubricants;
- Natural gas liquids distribution services and natural gas storage;
- Sulfur and sulfur-based products gathering, processing, marketing, manufacturing and distribution; and
- Marine transportation services for petroleum products and by-products.

The petroleum products and by-products we collect, transport, store and market are produced primarily by major and independent oil and gas companies who often turn to third parties, such as us, for the transportation and disposition of these products. In addition to these major and independent oil and gas companies, our primary customers include independent refiners, large chemical companies, fertilizer manufacturers and other wholesale purchasers of these products. We operate primarily in the U.S. Gulf Coast region. This region is a major hub for petroleum refining, natural gas gathering and processing, and support services for the exploration and production industry.

We were formed in 2002 by Martin Resource Management, a privately-held company whose initial predecessor was incorporated in 1951 as a supplier of products and services to drilling rig contractors. Since then, Martin Resource Management has expanded its operations through acquisitions and internal expansion initiatives as its management identified and capitalized on the needs of producers and purchasers of petroleum products and by-products and other bulk liquids. Martin Resource Management is an important supplier and customer of ours. As of December 31, 2013, Martin Resource Management owned 19.1% of our total outstanding common limited partner units. Furthermore, Martin Resource Management controls Martin Midstream GP LLC ("MMGP"), our general partner, by virtue of its 51% voting interest in MMGP Holdings, LLC ("Holdings"), the sole member of MMGP. MMGP owns a 2.0% general partner interest in us and all of our incentive distribution rights. Martin Resource Management directs our business operations through its ownership interests in and control of our general partner.

We entered into an omnibus agreement dated November 1, 2002, with Martin Resource Management (the "Omnibus Agreement") that governs, among other things, potential competition and indemnification obligations among the parties to the agreement, related party transactions, the provision of general administration and support services by Martin Resource Management and our use of certain of Martin Resource Management's trade names and trademarks. Under the terms of the Omnibus Agreement, the employees of Martin Resource Management are responsible for conducting our business and operating our assets.

Martin Resource Management has operated our business since 2002. Martin Resource Management began operating our natural gas services business in the 1950s and our sulfur business in the 1960s. It began our marine transportation business in the late 1980s. It entered into our fertilizer and terminalling and storage businesses in the early 1990s. In recent years, Martin Resource Management has increased the size of our asset base through expansions and strategic acquisitions.

Recent Developments

We believe one of the rationales driving investment in master limited partnerships, including us, is the opportunity for distribution growth offered by the partnerships. Such distribution growth is a function of having access to liquidity in the financial markets used for incremental capital investment (development projects and acquisitions) to grow distributable cash flow.

We continually adjust our business strategy to focus on maximizing liquidity, maintaining a stable asset base which generates fee based revenues not sensitive to commodity prices, and improving profitability by increasing asset utilization and controlling costs. Over the past year, we have had access to the capital markets and have appropriate levels of liquidity and operating cash flows to adequately fund our growth. Over the next two years, we plan to increase expansion capital expenditures primarily in our Terminalling and Storage and Natural Gas Services segments.

Recent Acquisitions

Marine Transportation Equipment Purchase. On September 30, 2013, we acquired two previously leased inland tank barges from Martin Resource Management for $7.1 million. This transaction was funded with borrowings under our revolving credit facility.

Sulfur Production Facility. On August 5, 2013, we purchased a plant nutrient sulfur production facility in Cactus, Texas for $4.1 million. This transaction was funded with borrowings under our revolving credit facility.

NL Grease, LLC. On June 13, 2013, we acquired certain assets of NL Grease, LLC (“NLG”) for approximately $12.1 million. NLG is a Kansas City, Missouri based grease manufacturer that specializes in private-label packaging of commercial and industrial greases. This transaction was funded with borrowings under our revolving credit facility.

Martin Energy Trading LLC. During March 2013, we acquired 100% of the preferred interests in Martin Energy Trading LLC (“MET”), a subsidiary of Martin Resource Management, for $15.0 million. This transaction was funded with borrowings under our revolving credit facility.

NGL Marine Equipment Purchase. On February 28, 2013, we purchased from affiliates of Florida Marine Transporters, Inc., six liquefied petroleum gas (“LPG”) pressure barges and two commercial push boats (“Florida Marine Assets”) for approximately $50.8 million. This transaction was funded with borrowings under our revolving credit facility.

Talen's Marine & Fuel LLC. On December 31, 2012, we acquired all of the outstanding membership interests in Talen's Marine & Fuel LLC (“Talen's”) from QEP Marine Fuel Investment, LLC and QEP Marine Fuel Holdings, Inc. (collectively referred to as “Quintana Energy Partners”) for $103.4 million, subject to certain post-closing adjustments. Simultaneous with the acquisition, we sold certain working capital-related assets to Martin Energy Services LLC (“MES”), a wholly-owned subsidiary of Martin Resource Management for $56.0 million, reducing our investment in Talen's to $47.4 million. This transaction was funded with borrowings under our revolving credit facility. In conjunction with its purchase of certain working capital-related assets, MES entered into various service agreements with Talen's pursuant to which we provide certain terminalling and marine services to MES.

Other Developments

Sale of general partner interest. On August 30, 2013, Martin Resource Management completed the sale of a 49% non-controlling voting interest (50% economic interest) in Holdings, the newly-formed sole member of MMGP, the general partner of the Partnership, to certain affiliated investment funds managed by Alinda Capital Partners (“Alinda”). Upon closing the transaction, Alinda appointed two representatives to serve on the board of directors of the general partner of the Partnership.

Debt Financing Activities

Amendment to Revolving Credit Facility. On March 28, 2013, we made certain strategic amendments to our credit facility which, among other things, increased our borrowing capacity from $400.0 million to $600.0 million and extended the maturity date of the facility from April 15, 2016 to March 28, 2018.

Issuance of 2021 Senior Unsecured Notes. On February 11, 2013, we completed a private placement of $250.0 million in aggregate principal amount of 7.250% senior unsecured notes due 2021 to qualified institutional buyers under Rule 144A. We received proceeds of approximately $245.1 million, after deducting initial purchasers' discounts and the expenses of the private placement. The proceeds were primarily used to repay borrowings under our revolving credit

facility. On July 1, 2013, we filed a registration statement on Form S-4 with the Securities and Exchange Commission ("SEC") to exchange the notes for registered 7.250% senior unsecured notes due February 2021. The exchange offer was completed on July 31, 2013.

For a more detailed discussion regarding our credit facility, see "Description of Our Long-Term Debt" within this Item.

Subsequent Events

Redemption of 2018 Senior Unsecured Notes. On February 28, 2014, we announced that we will exercise a full redemption of the 2018 senior unsecured notes pursuant to the indenture, on or about April 1, 2014 at an aggregate redemption value of $182.8 million. We expect to fund the redemption under borrowings from our revolving credit facility.

Amendment to Revolving Credit Facility. On February 18, 2014, we increased the maximum amount of borrowings under our revolving credit facility from $600.0 million to $637.5 million by utilizing the accordion feature of our revolving credit facility.

Quarterly Distribution. On January 23, 2014, we declared a quarterly cash distribution of $0.785 per common unit for the fourth quarter of 2013, or $3.14 per common unit on an annualized basis, which was paid on February 14, 2014 to unitholders of record as of February 7, 2014.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based on the historical consolidated financial statements included elsewhere herein. We prepared these financial statements in conformity with United States generally accepted accounting principles ("U.S. GAAP" or "GAAP"). The preparation of these financial statements required us to make estimates and assumptions that affect the reported amounts of assets and liabilities at the dates of the financial statements and the reported amounts of revenues and expenses during the reporting periods. We based our estimates on historical experience and on various other assumptions we believe to be reasonable under the circumstances. We routinely evaluate these estimates, utilizing historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Our results may differ from these estimates, and any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known. Changes in these estimates could materially affect our financial position, results of operations or cash flows. You should also read Note 2, "Significant Accounting Policies" in Notes to Consolidated Financial Statements. The following table evaluates the potential impact of estimates utilized during the periods ended December 31, 2013 and 2012:

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
Allowance for Doubtful Accounts		
We evaluate our allowance for doubtful accounts on an ongoing basis and record adjustments when, in management's judgment, circumstances warrant it. Reserves are recorded to reduce receivables to the amount ultimately expected to be collected.	We evaluate the collectability of our accounts receivable based on factors such as the customer's ability to pay, the age of the receivable and our historical collection experience. A deterioration in any of these factors could result in an increase in the allowance for doubtful accounts balance.	If actual collection results are not consistent with our judgments, we may experience an increase in uncollectible receivables. A 10% increase in our allowance for doubtful accounts would result in a decrease in net income of approximately $0.2 million.
Depreciation		
Depreciation expense is computed using the straight-line method over the useful life of the assets.	Determination of depreciation expense requires judgment regarding estimated useful lives and salvage values of property, plant and equipment. As circumstances warrant, estimates are reviewed to determine if any changes in the underlying assumptions are needed.	The lives of our fixed assets range from 3 - 25 years. If the depreciable lives of our assets were decreased by 10%, we estimate that annual depreciation expense would increase approximately $5.5 million, resulting in a corresponding reduction in net income.
Impairment of Long-Lived Assets		
We periodically evaluate whether the carrying value of long-lived assets	Our impairment analyses require management to use judgment in	Applying this impairment review methodology, we have recorded no

has been impaired when circumstances indicate the carrying value of the assets may not be recoverable. These evaluations are based on undiscounted cash flow projections over the remaining useful life of the asset. The carrying value is not recoverable if it exceeds the sum of the undiscounted cash flows. Any impairment loss is measured as the excess of the asset's carrying value over its fair value.

Impairment of Goodwill

estimating future cash flows and useful lives, as well as assessing the probability of different outcomes.

impairment charges during the periods ended December 31, 2013, 2012 and 2011. If actual events are not consistent with our estimates and assumptions or our estimates and assumptions change due to new information, we may incur an impairment charge.

Goodwill is subject to a fair-value based impairment test on an annual basis, or more frequently if events or changes in circumstances indicate that the fair value of any of our reporting units is less than its carrying amount.	We determine fair value using accepted valuation techniques, including discounted cash flow and the guideline public company method. These analyses require management to make assumptions and estimates regarding industry and economic factors, future operating results and discount rates. We conduct impairment testing using present economic conditions, as well as future expectations.	We completed the most recent annual review of goodwill as of August 31, 2013 and determined there was no impairment. Additionally, management is aware of no change in circumstances which indicate a need for an interim impairment evaluation.
Purchase Price Allocations		
We allocate the purchase price of an acquired business to its identifiable assets (including identifiable intangible assets) and liabilities based on their fair values at the date of acquisition. Any excess of purchase price in excess of amounts allocated to identifiable assets and liabilities is recorded as goodwill. As additional information becomes available, we may adjust the preliminary allocation for a period of up to one year.	The determination of fair values of acquired assets and liabilities requires a significant level of management judgment. Fair values are estimated using various methods as deemed appropriate. For significant transactions, third party assessments may be utilized to assist in the valuation process.	If subsequent factors indicate that estimates and assumptions used to allocate costs to acquired assets and liabilities differ from actual results, the allocation between goodwill, other intangible assets and fixed assets could significantly differ. Any such differences could impact future earnings through depreciation and amortization expense. Additionally, if estimated results supporting the valuation of goodwill or other intangible assets are not achieved, impairments could result.
Asset Retirement Obligations Asset retirement obligations (“AROs”) associated with a contractual or regulatory remediation requirement are recorded at fair value in the period in which the obligation can be reasonably estimated and depreciated over the life of the related asset or contractual term. The liability is determined using a credit-adjusted risk-free interest rate and is accreted over time until the obligation is settled.	Determining the fair value of AROs requires management judgment to evaluate required remediation activities, estimate the cost of those activities and determine the appropriate interest rate.	If actual results differ from judgments and assumptions used in valuing an ARO, we may experience significant changes in ARO balances. The establishment of an ARO has no initial impact on earnings.
Environmental Liabilities We estimate environmental liabilities using both internal and external resources. Activities include feasibility studies and other evaluations management considers appropriate. Environmental liabilities are recorded in the period in which the obligation can be reasonably estimated.	Estimating environmental liabilities requires significant management judgment as well as possible use of third party specialists knowledgeable in such matters.	Environmental liabilities have not adversely affected our results of operations or financial condition in the past, and we do not anticipate that they will in the future.

Our Relationship with Martin Resource Management

Martin Resource Management directs our business operations through its ownership and control of our general partner and under the Omnibus Agreement. In addition to the direct expenses, under the Omnibus Agreement, we are required to reimburse Martin Resource Management for indirect general and administrative and corporate overhead expenses. For the years ended December 31, 2013, 2012 and 2011, the conflicts committee of our general partner ("Conflicts Committee") approved reimbursement amounts of $10.6 million, $7.6 million and $4.8 million, respectively, reflecting our allocable share of such expenses. The Conflicts Committee will review and approve future adjustments in the reimbursement amount for indirect expenses, if any, annually.

We are required to reimburse Martin Resource Management for all direct expenses it incurs or payments it makes on our behalf or in connection with the operation of our business. Martin Resource Management also licenses certain of its trademarks and trade names to us under the Omnibus Agreement.

We are both an important supplier to and customer of Martin Resource Management. Among other things, we sell sulfuric acid and provide marine transportation and terminalling and storage services to Martin Resource Management. We

purchase land transportation services, underground storage services, and marine fuel from Martin Resource Management. All of these services and goods are purchased and sold pursuant to the terms of a number of agreements between us and Martin Resource Management.

For a more comprehensive discussion concerning the Omnibus Agreement and the other agreements that we have entered into with Martin Resource Management, please see “Item 13. Certain Relationships and Related Transactions, and Director Independence – Agreements.”

How We Evaluate Our Operations

Our management uses a variety of financial and operational measurements other than our financial statements prepared in accordance with U.S. GAAP to analyze our performance. These include: (1) net income before interest expense, income tax expense, and depreciation and amortization (“EBITDA”), (2) adjusted EBITDA and (3) distributable cash flow. Our management views these measures as important performance measures of core profitability for our operations and the ability to generate and distribute cash flow, and as key components of our internal financial reporting. We believe investors benefit from having access to the same financial measures that our management uses.

EBITDA and Adjusted EBITDA. Certain items excluded from EBITDA and adjusted EBITDA are significant components in understanding and assessing an entity's financial performance, such as cost of capital and historic costs of depreciable assets. We have included information concerning EBITDA and adjusted EBITDA because they provide investors and management with additional information to better understand the following: financial performance of our assets without regard to financing methods, capital structure or historical cost basis; our operating performance and return on capital as compared to those of other similarly situated entities; and the viability of acquisitions and capital expenditure projects. Our method of computing adjusted EBITDA may not be the same method used to compute similar measures reported by other entities. The economic substance behind our use of adjusted EBITDA is to measure the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make distributions to our unit holders.

Distributable Cash Flow. Distributable cash flow is a significant performance measure used by our management and by external users of our financial statements, such as investors, commercial banks and research analysts, to compare basic cash flows generated by us to the cash distributions we expect to pay our unitholders. Distributable cash flow is also an important financial measure for our unitholders since it serves as an indicator of our success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not we are generating cash flow at a level that can sustain or support an increase in our quarterly distribution rates. Distributable cash flow is also a quantitative standard used throughout the investment community with respect to publicly-traded partnerships because the value of a unit of such an entity is generally determined by the unit's yield, which in turn is based on the amount of cash distributions the entity pays to a unitholder.

EBITDA, adjusted EBITDA and distributable cash flow should not be considered alternatives to, or more meaningful than, net income, cash flows from operating activities, or any other measure presented in accordance with U.S. GAAP. Our method of computing these measures may not be the same method used to compute similar measures reported by other entities.

Non-GAAP Financial Measures

The following table reconciles the non-GAAP financial measurements used by management to our most directly comparable GAAP measures for the years ended December 31, 2013, 2012, and 2011, which represents EBITDA, Adjusted EBITDA and Distributable Cash Flow from continuing operations.

Reconciliation of EBITDA, Adjusted EBITDA, and Distributable Cash Flow

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	Year Ended December 31,		
	2013	2012	2011
Net income (loss)	$(13,354)	$101,987	$22,759
Less: Income from discontinued operations, net of income taxes	—	(64,865)	(9,392)
Income from continuing operations	(13,354)	37,122	13,367
Adjustments:			
Interest expense	42,495	30,665	26,781
Income tax expense	753	3,557	2,872
Depreciation and amortization	52,240	42,063	40,276
EBITDA	82,134	113,407	83,296
Adjustments:			
Equity in loss of unconsolidated entities	53,048	1,113	4,752
(Gain) loss on sale of property, plant and equipment	(217)	795	899
Gain on sale of equity method investment	(750)	(486)	—
Gain on involuntary conversion of property, plant and equipment	(909)	—	—
Debt prepayment premium	272	2,470	—
Distributions from unconsolidated entities	3,476	3,961	1,432
Mont Belvieu indemnity escrow payment	—	(375)	—
Unit-based compensation	911	385	190
Adjusted EBITDA	137,965	121,270	90,569
Adjustments:			
Interest expense	(42,495)	(30,665)	(26,781)
Income tax expense	(753)	(3,557)	(2,872)
Amortization of deferred debt issuance costs	3,700	3,290	3,755
Amortization of debt discount	306	581	351
Payments of installment notes payable and capital lease obligations	(307)	(279)	(1,132)
Deferred income taxes	—	402	622
Non-cash operating lease expense	—	—	69
Payments for plant turnaround costs	—	(2,107)	(2,103)
Maintenance capital expenditures	(11,445)	(8,658)	(9,807)
Distributable Cash Flow	$86,971	$80,277	$52,671

Results of Operations

The results of operations for the years ended December 31, 2013, 2012, and 2011 have been derived from our consolidated financial statements.

We evaluate segment performance on the basis of operating income, which is derived by subtracting cost of products sold, operating expenses, selling, general and administrative expenses, and depreciation and amortization expense from revenues. The following table sets forth our operating revenues and operating income by segment for the years ended December 31, 2013, 2012, and 2011.

Our consolidated results of operations are presented on a comparative basis below. There are certain items of income and expense which we do not allocate on a segment basis. These items, including equity in earnings (loss) of unconsolidated entities, interest expense, and indirect selling, general and administrative expenses, are discussed after the comparative discussion of our results within each segment.

The Natural Gas Services segment information below excludes the discontinued operations of our natural gas gathering and processing assets (as described in Item 8, Note 5 and collectively referred to as the "Prism Assets") for all periods.

	Operating Revenues	Revenues Intersegment Eliminations	Operating Revenues after Eliminations	Operating Income (loss)	Operating Income Intersegment Eliminations	Operating Income (loss) after Eliminations
	(In thousands)					
Year Ended December 31, 2013:						
Terminalling and storage	$341,966	$(4,756)	$337,210	$35,282	$(2,427)	$32,855
Natural gas services	987,681	—	987,681	29,212	2,521	31,733
Sulfur services	213,124	—	213,124	26,002	(4,491)	21,511
Marine transportation	99,510	(4,015)	95,495	9,013	4,397	13,410
Indirect selling, general and administrative	—	—	—	(16,837)	—	(16,837)
Total	$1,642,281	$(8,771)	$1,633,510	$82,672	$—	$82,672
Year Ended December 31, 2012:						
Terminalling and storage	$322,175	$(4,652)	$317,523	$27,944	$(2,541)	$25,403
Natural gas services	825,506	—	825,506	13,924	1,471	15,395
Sulfur services	261,584	—	261,584	37,262	4,647	41,909
Marine transportation	88,815	(3,067)	85,748	6,751	(3,577)	3,174
Indirect selling, general and administrative	—	—	—	(12,046)	—	(12,046)
Total	$1,498,080	$(7,719)	$1,490,361	$73,835	$—	$73,835
Year Ended December 31, 2011:						
Terminalling and storage	$283,175	$(4,414)	$278,761	$21,567	$(948)	$20,619
Natural gas services	611,749	—	611,749	6,267	1,220	7,487
Sulfur services	275,044	—	275,044	27,651	6,944	34,595
Marine transportation	83,971	(7,035)	76,936	731	(7,216)	(6,485)
Indirect selling, general and administrative	—	—	—	(8,864)	—	(8,864)
Total	$1,253,939	$(11,449)	$1,242,490	$47,352	$—	$47,352

Terminalling and Storage Segment

Comparative Results of Operations for the Twelve Months Ended December 31, 2013 and 2012

	Year Ended December 31,		Variance	Percent Change
	2013	2012		
	(In thousands)			
Revenues:				
Services	$120,717	$94,895	$25,822	27%
Products	221,249	227,280	(6,031)	(3)%
Total revenues	341,966	322,175	19,791	6%
Cost of products sold	197,974	207,699	(9,725)	(5)%
Operating expenses	74,441	58,766	15,675	27%
Selling, general and administrative expenses	3,238	4,671	(1,433)	(31)%
Depreciation and amortization	31,823	22,976	8,847	39%
	34,490	28,063	6,427	23%
Other operating income (loss)	792	(119)	911	766%
Operating income	$35,282	$27,944	$7,338	26%
Lubricant sales volumes (gallons)	39,342	38,107	1,235	3%
Shore-based throughput volumes (gallons)	270,522	218,494	52,028	24%
Smackover refinery throughput volumes (barrel per day)	6,912	5,994	918	15%
Corpus Christi crude terminal throughput volumes (barrel per day)	108,652	55,529	53,123	96%

Services revenues. Services revenue increased primarily due to $17.7 million attributable to our new crude terminal in Corpus Christi, Texas, which was placed into service in May 2012. In addition, $5.2 million of the increase is due to revenues generated by our Talen's acquisition on December 31, 2012. The remaining increase is primarily due to increased throughput at the Smackover refinery.

Products revenues. An 8% increase in sales volumes at our blending and packaging facilities resulted in a $10.7 million positive impact on product revenues. Product sales volumes from our shore-based terminals decreased 7%, resulting in $5.6 million reduction in product revenues. The average sales price at our blending and packaging facilities decreased 5%, resulting in a $7.8 million decrease in product revenues. The average sales price at our shore-based terminals decreased 4%, resulting in a $3.3 million decrease in product revenues.

Cost of products sold. An 8% increase in sales volumes at our blending and packaging facilities resulted in a $9.4 million increase in cost of products sold, which was partially offset by a 7% decrease in sales volumes at our shore-based terminals, resulting in a $5.2 million decrease in cost of products sold. Decreased average cost at our blending and packaging facilities of 8% resulted in a decrease of $10.0 million in cost of products sold. Decreased average cost at our shore-based terminals of 5% resulted in a decrease of $3.9 million in cost of products sold.

Operating expenses. Increased expenses at our specialty terminals accounted for $6.9 million of the total increase, primarily attributable to the Corpus Christi crude terminal. Our shore-based terminal expenses increased $1.7 million primarily due to the acquisition of the Talen's terminals. In addition, $7.1 million of the increase is attributable to the Smackover refining assets, primarily as a result of increased utilities and repairs and maintenance expense.

Selling, general and administrative expenses. The decrease in selling, general and administrative expenses is primarily related to decreased advertising expense in our blending and packaging operations.

Depreciation and amortization. The increase in depreciation and amortization is due to the impact of recent capital expenditures.

Other operating income (loss). The increase in other operating income (loss) is primarily attributable to a gain in 2013 on an involuntary conversion resulting from a tank fire that occurred in the third quarter of 2011.

Comparative Results of Operations for the Twelve Months Ended December 31, 2012 and 2011

	Year Ended December 31,		Variance	Percent Change
	2012	2011		
	(In thousands)			
Revenues:				
Services	$94,895	$81,697	$13,198	16%
Products	227,280	201,478	25,802	13%
Total revenues	322,175	283,175	39,000	14%
Cost of products sold	207,699	185,879	21,820	12%
Operating expenses	58,766	52,041	6,725	13%
Selling, general and administrative expenses	4,671	3,343	1,328	40%
Depreciation and amortization	22,976	19,814	3,162	16%
	28,063	22,098	5,965	27%
Other operating loss	(119)	(531)	412	78%
Operating income	$27,944	$21,567	$6,377	30%
Lubricant sales volumes (gallons)	38,107	36,189	1,918	5%
Shore-based throughput volumes (gallons)	218,494	216,410	2,084	1%
Smackover refinery throughput volumes (barrels per day)	5,994	6,820	(826)	(12)%
Corpus Christi crude terminal (barrels per day)	55,529	—	55,529	

Services revenues. Services revenue increased primarily due to additional revenue of $8.6 million attributable to our new crude terminal in Corpus Christi, Texas, which was placed into service in the second quarter of 2012. In addition, $3.8 million of the increase is due to revenues generated by the Sunoco Pipeline which was placed into service in the fourth quarter of 2011.

Products revenues. A 9% increase in sales volumes at our blending and packaging facilities resulted in a $12.4 million positive impact on product revenues. Product sales volumes from our shore-based terminals decreased 3%, resulting in $2.4 million reduction in product revenues. The average sales price at our blending and packaging facilities increased 6%, resulting in a $7.6 million increase in product revenues. The average sales price at our shore-based terminals increased 11%, resulting in an $8.2 million increase in product revenues.

Cost of products sold. A 9% increase in sales volumes at our blending and packaging facilities resulted in an $11.1 million increase in cost of products sold, which was partially offset by a 3% decrease in sales volumes from at our shore-based terminals, resulting in a $2.3 million decrease in cost of products sold. Increased average cost at our blending and packaging facilities of 5%, resulted in an increase of $5.7 million in cost of products sold. Increased average cost at our shore-based terminals of 10%, resulted in an increase of $7.3 million in cost of products sold.

Operating expenses. Increased expenses for the specialty terminals accounted for $2.7 million of the total increase, primarily attributable to the Corpus Christi crude terminal. In addition, $3.5 million of the increase is related to the Smackover refining assets, primarily attributable to the Sunoco pipeline.

Selling, general and administrative expenses. Selling, general and administrative expenses increased primarily due to increased advertising expense in our blending and packing operations.

Depreciation and amortization. The increase in depreciation and amortization is due to the impact of recent capital expenditures.

Other operating loss. Other operating loss represents losses on the disposal of property, plant and equipment.

Natural Gas Services Segment

Comparative Results of Operations for the Twelve Months Ended December 31, 2013 and 2012

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	Year Ended December 31,		Variance	Percent Change
	2013	2012		
	(In thousands)			
Revenues:				
Marine transportation	$3,028	$—	$3,028	
Products	984,653	825,506	159,147	19%
Total revenues	987,681	825,506	162,175	20%
Cost of products sold	946,551	803,195	143,356	18%
Operating expenses	5,806	3,550	2,256	64%
Selling, general and administrative expenses	3,892	4,236	(344)	(8)%
Depreciation and amortization	2,240	601	1,639	273%
	29,192	13,924	15,268	110%
Other operating income	20	—	20	
Operating income	$29,212	$13,924	$15,288	110%
NGLs Volumes (barrels)	15,168	12,080	3,088	26%

Revenues. The marine transportation revenue is attributable to our acquisition of the Florida Marine Assets on February 28, 2013. Natural gas services sales volumes increased 26%, positively impacting revenues $200.4 million, primarily as a result of us entering the Louisiana butane market during April 2012. Our NGL average sales price per barrel decreased $3.42, or 5%, resulting in an offsetting decrease to revenues of $41.3 million.

Cost of products sold. Our average cost per barrel decreased $4.08, or 6%. Our margins increased $0.67 per barrel during the period, primarily related to increased margins resulting from our entrance into the Louisiana butane market in April 2012.

Operating expenses. Operating expenses increased primarily as a result of outside towing, tankerman, and fuel expenses associated with the newly acquired Florida Marine Assets of $1.5 million, higher property and liability premiums of $0.3 million, and increased pipeline maintenance expenses of $0.2 million.

Selling, general and administrative expenses. Selling, general and administrative expenses decreased primarily as a result of the reserve for an uncollectible customer receivable in 2012 of $0.7 million and the recovery of an uncollectible customer receivable in 2013 of $0.3 million. These decreases were partially offset by increased compensation expense of $0.3 million and increased property tax expense of $0.1 million.

Depreciation and amortization. Depreciation and amortization increased as a result of the acquisition of the Florida Marine Assets during the first quarter of 2013.

Comparative Results of Operations for the Twelve Months Ended December 31, 2012 and 2011

	Year Ended December 31,		Variance	Percent Change
	2012	2011		
	(In thousands)			
Revenues	$825,506	$611,749	$213,757	35%
Cost of products sold	803,195	600,034	203,161	34%
Operating expenses	3,550	2,994	556	19%
Selling, general and administrative expenses	4,236	1,876	2,360	126%
Depreciation and amortization	601	578	23	4%
Operating income	$13,924	$6,267	$7,657	122%
NGLs Volumes (barrels)	12,080	7,866	4,214	54%

Revenues. Natural gas services sales volumes increased 54%, positively impacting revenues $288.0 million, primarily as a result of us entering the Louisiana butane market during April 2012. Our NGL average sales price per barrel decreased $9.44, or 12%, resulting in an offsetting decrease to revenues of $74.2 million.

Cost of products sold. Our average cost per barrel decreased $9.79, or 12%. Our margins increased $0.36 per barrel during the period, primarily related to increased margins resulting from our entrance into the Louisiana butane market in April 2012.

Operating expenses. Operating expenses increased primarily as a result of increased pipeline maintenance expenses of $0.2 million and increased compensation expense of $0.2 million.

Selling, general and administrative expenses. Selling, general and administrative expenses increased primarily as a result of increased compensation expense of $1.4 million and an increase in bad debt expense of $0.7 million.

Depreciation and amortization. Depreciation and amortization remained consistent from year to year.

Sulfur Services Segment

Comparative Results of Operations for the Twelve Months Ended December 31, 2013 and 2012

	Year Ended December 31,		Variance	Percent Change
	2013	2012		
	(In thousands)			
Revenues:				
Services	$12,004	$11,702	$302	3%
Products	201,120	249,882	(48,762)	(20)%
Total revenues	213,124	261,584	(48,460)	(19)%
Cost of products sold	158,085	195,314	(37,229)	(19)%
Operating expenses	16,975	17,404	(429)	(2)%
Selling, general and administrative expenses	4,083	3,975	108	3%
Depreciation and amortization	7,979	7,371	608	8%
	26,002	37,520	(11,518)	(31)%
Other operating loss	—	(258)	258	100%
Operating income	$26,002	$37,262	$(11,260)	(30)%

Sulfur (long tons)	836.6	959.9	(123.3)	(13)%
Fertilizer (long tons)	273.0	306.1	(33.1)	(11)%
Sulfur services volumes (long tons)	1,109.6	1,266.0	(156.4)	(12)%

Revenues. The increase in service revenue is attributable to increased contract rates. Product revenue declined $28.3 million as a result of a 12% decrease in sales volumes. The volume reduction was primarily related to the conversion of a buy/sell contract with a major customer to a fee-based handling contract. Additionally, product revenues decreased $20.4 million due to an 8% decline in sales prices where our sulfur products saw a decrease in sales prices of 14% and our fertilizer products saw a decrease in sales prices of 3%.

Cost of products sold. A 12% decrease in sales volumes reduced cost of products sold by $22.3 million. An 8% decrease in prices reduced our cost by an additional $14.9 million. Margin per ton decreased $4.32, or 10%, resulting in a decline in gross margin of $11.5 million, primarily attributable to the decline in market prices discussed above. Also contributing to the decline in the gross margin of our fertilizer business was significant downtime attributable to plant turnarounds at our Plainview and Neches production facilities. Costs associated with these turnarounds were $1.2 million higher than the same period of 2012.

Operating expenses. Our operating expenses decreased due to $0.8 million less in outside towing expenses offset by increased compensation expense of $0.6 million.

Selling, general and administrative expenses. Selling, general and administrative expenses increased as a result of increased compensation expense.

Depreciation and amortization. The increase in depreciation and amortization is due to the impact of recent capital expenditures.

Other operating loss. Other operating loss represents losses on the disposal of property, plant and equipment in 2012.

Comparative Results of Operations for the Twelve Months Ended December 31, 2012 and 2011

	Year Ended December 31,		Variance	Percent Change
	2012	2011		
	(In thousands)			
Revenues:				
Services	$11,702	$11,400	$302	3%
Products	249,882	263,644	(13,762)	(5)%
Total revenues	261,584	275,044	(13,460)	(5)%
Cost of products sold	195,314	220,059	(24,745)	(11)%
Operating expenses	17,404	19,328	(1,924)	(10)%
Selling, general and administrative expenses	3,975	3,361	614	18%
Depreciation and amortization	7,371	6,725	646	10%
	37,520	25,571	11,949	47%
Other operating income (loss)	(258)	2,080	(2,338)	(112)%
Operating income	$37,262	$27,651	$9,611	35%
Sulfur (long tons)	959.9	1,217.0	(257.1)	(21)%
Fertilizer (long tons)	306.1	271.8	34.3	13%
Sulfur services volumes (long tons)	1,266.0	1,488.8	(222.8)	(15)%

Revenues. The increase in service revenue is attributable to increased contract rates. The volume reduction was primarily related to the conversion of a buy/sell contract with a major customer to a fee-based handling contract.

Revenue declined $44.0 million as a result of a 15% decrease in sales volumes. Offsetting this was an increase of $30.2 million due to an 11% increase in sales price where our sulfur products saw an increase in sales prices of 2% and our fertilizer products saw an increase in sales prices of 9%.

Cost of products sold. A 15% decrease in volumes reduced cost of products sold by $34.4 million. Offsetting this was an increase in prices of 4%, increasing products costs by $9.7 million. Margin per ton increased $13.83, or 47%, resulting in an increase in gross margin of $11.0 million, primarily attributable to an increase in market prices related to our fertilizer products.

Operating expenses. Our operating expenses decreased primarily as a result of lower outside towing expenses of $1.8 million and $0.4 million in lower workers compensation claims. These decreases were offset by an increase of $0.3 million in marine fuel expense.

Selling, general and administrative expenses. Selling, general and administrative expenses increased as a result of increased compensation expense.

Depreciation and amortization. The increase in depreciation and amortization is due to the impact of recent capital expenditures.

Other operating income (loss). Other operating income (loss) decreased primarily from a $1.4 million gain on termination of a rail services agreement and $0.7 million business interruption recovery, both of which occurred in 2011.

Marine Transportation Segment

Comparative Results of Operations for the Twelve Months Ended December 31, 2013 and 2012

	Year Ended December 31,		Variance	Percent Change
	2013	2012		
	(In thousands)			
Revenues	$99,510	$88,815	$10,695	12%
Operating expenses	79,306	70,342	8,964	13%
Selling, general and administrative expenses	1,347	566	781	138%
Depreciation and amortization	10,198	11,115	(917)	(8)%
	8,659	6,792	1,867	27%
Other operating income (loss)	354	(41)	395	963%
Operating income	$9,013	$6,751	$2,262	34%

Inland Revenues. An $11.2 million increase in inland revenues is primarily attributable to $8.4 million from the Talen's acquisition and $3.1 million from the Florida Marine Assets.

Offshore Revenues. Revenue from offshore operations increased $0.4 million due to an increase in utilization. Ancillary revenue, primarily fuel, decreased $1.0 million.

Operating expenses. Operating expenses increased $9.0 million as a result of costs and expenses associated with the acquisitions of the Talen's and Florida Marine Assets.

Selling, general and administrative expenses. Selling, general and administrative expenses increased primarily as a result of the 2012 period including the recovery of a previously uncollectible customer receivable.

Depreciation and amortization. Depreciation and amortization decreased as a result of the disposal of equipment, offset by increases in depreciable assets related to recent capital expenditures.

Other operating income (loss). Other operating income (loss) increased as a result of gains recognized on the disposal of equipment.

Comparative Results of Operations for the Twelve Months Ended December 31, 2012 and 2011

	Year Ended December 31,		Variance	Percent Change
	2012	2011		
	(In thousands)			
Revenues	$88,815	$83,971	$4,844	6%
Operating expenses	70,342	66,771	3,571	5%
Selling, general and administrative expenses	566	3,087	(2,521)	(82)%
Depreciation and amortization	11,115	13,159	(2,044)	(16)%
	6,792	954	5,838	612%
Other operating loss	(41)	(223)	182	82%
Operating income	$6,751	$731	$6,020	824%

Inland Revenues. Revenue from inland operations decreased $2.8 million due to a decrease in utilization. Ancillary revenue, primarily fuel, increased $0.4 million.

Offshore Revenues. Revenue from offshore operations increased $5.5 million due to an increase in utilization. Ancillary revenue, primarily fuel, increased $1.8 million.

Operating expenses. The increase in operating expenses is due to increased fuel costs of $2.4 million, compensation expense of $1.6 million, claims expense of $0.4 million, assist tugs of $0.3 million, and a write-off of supplies inventory of $1.2 million. Offsetting these increases are decreases in outside towing of $1.3 million and barge lease expense of $1.0 million.

Selling, general and administrative expenses. Selling, general and administrative expenses decreased as a result of the collection of a previously reserved customer receivable of $2.1 million and a $0.4 million decrease in bad debt expense in 2012.

Depreciation and amortization. Depreciation and amortization decreased as a result of the disposal of equipment, offset by increases in depreciable assets related to recent capital expenditures.

Other operating loss. Other operating loss represents losses on asset dispositions.

Equity in Earnings (Loss) of Unconsolidated Entities

	Year Ended December 31,		Variance	Percent Change
	2013	2012		
	(In thousands)			
Equity in loss of Cardinal	$(54,226)	$(943)	$(53,283)	(5,650)%
Equity in earnings of MET	1,738	—	1,738	
Equity in loss of Caliber	(560)	(190)	(370)	(195)%
Equity in earnings of Pecos Valley	—	20	(20)	(100)%
Equity in loss of unconsolidated entities	$(53,048)	$(1,113)	$(51,935)	(4,666)%

Equity in loss of Cardinal Gas Storage Partners LLC (“Cardinal”) increased principally due to the recognition of an impairment charge, of which our portion was $54.1 million of impairment related to the long-lived assets of Monroe Gas Storage Company, LLC (“Monroe”), a subsidiary of Cardinal. In addition, 2013 includes a one-time charge for incentive payments resulting from the completion of Cadeville Gas Storage, LLC (“Cadeville”) and Perryville Gas Storage, LLC (“Perryville”) ahead of schedule and under budget. The 2013 period also includes a one-time charge for employee severance costs related to the discontinuation of Cardinal's gas consulting business. The aggregate impact of these one-time charges to us was $1.8 million. Improved Cardinal results of operations attributable to the completion

of the Cadeville and Perryville projects partially offset the negative impact of these items. A $2.2 million milestone payment is included in Cardinal's equity in loss in the twelve months ended December 31, 2012. No milestone payments were received in 2013.

Equity in earnings of MET represents dividends on our 100% investment in its preferred interests. The MET investment was acquired in March 2013.

The $0.4 million decrease in equity in loss of Caliber Gathering, LLC (“Caliber”) is attributable to Caliber's decline in earnings for the twelve months ended December 31, 2013. The Caliber investment was acquired in June 2012 and sold in November 2013.

The Pecos Valley Producer Services LLC (“Pecos Valley”) investment was sold in August 2012.

	Year Ended December 31,		Variance	Percent Change
	2012	2011		
	(In thousands)			
Equity in loss of Cardinal	$(943)	$(4,752)	$3,809	(80)%
Equity in loss of Caliber	(190)	—	(190)	
Equity in earnings of Pecos Valley	20	—	20	
Equity in loss of unconsolidated entities	$(1,113)	$(4,752)	$3,639	(77)%

Equity in loss of Cardinal decreased $3.8 million. A $2.2 million milestone payment is included in Cardinal's equity in earnings in the twelve months ended December 31, 2012. No milestone payments were received in 2011. The remaining increase in equity in earnings of Cardinal is attributable to improved results of operations in 2012.

Initial equity in earnings (loss) of Caliber and Pecos Valley Producer were recorded in June 2012. The Caliber and Pecos Valley investments were sold in November 2013 and August 2012, respectively.

Interest Expense

Comparative Components of Interest Expense for the Twelve Months Ended December 31, 2013 and 2012

	Year Ended December 31,		Variance	Percent Change
	2013	2012		
	(In thousands)			
Revolving loan facility	$7,683	$9,644	$(1,961)	(20)%
8.875 % senior unsecured notes	15,531	16,413	(882)	(5)%
7.250 % senior unsecured notes	16,061	—	16,061	
Amortization of deferred debt issuance costs	3,700	3,290	410	12%
Amortization of debt discount	306	581	(275)	(47)%
Interest costs attributable to the recast financial information of certain blending and packaging assets	—	1,549	(1,549)	(100)%
Notes payable and other	310	324	(14)	(4)%
Capitalized interest	(1,096)	(1,136)	40	4%
Total interest expense	$42,495	$30,665	$11,830	39%

Comparative Components of Interest Expense for the Twelve Months Ended December 31, 2012 and 2011

	Year Ended December 31,		Variance	Percent Change
	2012	2011		
	(In thousands)			
Revolving loan facility	$9,644	$8,210	$1,434	17%
8.875 % senior unsecured notes	16,413	17,750	(1,337)	(8)%
Mark to market adjustments and cash settlements on interest rate swaps related to the 8.875% senior unsecured notes	—	(5,779)	5,779	100%
Amortization of deferred debt issuance costs	3,290	3,755	(465)	(12)%
Amortization of debt discount	581	351	230	66%
Interest costs attributable to the recast financial information of certain blending and packaging assets	1,549	2,263	(714)	(32)%
Notes payable and other	324	855	(531)	(62)%
Capitalized interest	(1,136)	(624)	(512)	(82)%
Total interest expense	$30,665	$26,781	$3,884	15%

Indirect Selling, General and Administrative Expenses

	Year Ended December 31,		Variance	Percent Change	Year Ended December 31,		Variance	Percent Change
	2013	2012			2012	2011		
	(In thousands)				(In thousands)			
Indirect selling, general and administrative expenses	$16,837	$12,046	$4,791	40%	$12,046	$8,864	$3,182	36%

The increase in indirect selling, general and administrative expenses for both 2013 and 2012 is primarily a result of higher allocated overhead expenses from Martin Resource Management as a result of increased time spent on Partnership activities.

Martin Resource Management allocates to us a portion of its indirect selling, general and administrative expenses for services such as accounting, treasury, clerical, engineering, legal, billing, information technology, administration of insurance, general office expenses and employee benefit plans and other general corporate overhead functions we share with Martin Resource Management retained businesses. This allocation is based on the percentage of time spent by Martin Resource Management personnel that provide such centralized services. GAAP also permits other methods for allocation of these expenses, such as basing the allocation on the percentage of revenues contributed by a segment. The allocation of these expenses between Martin Resource Management and us is subject to a number of judgments and estimates, regardless of the method used. We can provide no assurances that our method of allocation, in the past or in the future, is or will be the most accurate or appropriate method of allocation for these expenses. Other methods could result in a higher allocation of selling, general and administrative expense to us, which would reduce our net income.

Under the Omnibus Agreement, we are required to reimburse Martin Resource Management for indirect general and administrative and corporate overhead expenses. The Conflicts Committee approved the following reimbursement amounts:

	Year Ended December 31,		Variance	Percent Change	Year Ended December 31,		Variance	Percent Change
	2013	2012			2012	2011		
	(In thousands)				(In thousands)			

Conflicts Committee approved reimbursement amount	$10,621	$7,593	$3,028	40%	$7,593	$4,772	$2,821	59%

The amounts reflected above represent our allocable share of such expenses. The Conflicts Committee will review and approve future adjustments in the reimbursement amount for indirect expenses, if any, annually.

Liquidity and Capital Resources

General

Our primary sources of liquidity to meet operating expenses, pay distributions to our unitholders and fund capital expenditures are cash flows generated by our operations and access to debt and equity markets, both public and private. We have recently completed several transactions that have improved our liquidity position, helping fund our acquisitions and organic growth projects. In February 2013, we received net proceeds of $245.1 million from a private placement of senior unsecured notes. Under the registration rights agreement related to this issuance, we filed with the SEC a registration statement to exchange these notes for substantially identical notes that are registered under the Securities Act, and completed the exchange offer on July 31, 2013. We made certain strategic amendments under our revolving credit facility, including most recently in February 2014 when we increased our maximum borrowing capacity from $600.0 million to $637.5 million utilizing the accordion feature of our revolving credit facility.

As a result of these financing activities, discussed in further detail below, management believes that expenditures for our current capital projects will be funded with cash flows from operations, current cash balances and our current borrowing capacity under the expanded revolving credit facility. However, it may be necessary to raise additional funds to finance our future capital requirements.

Our ability to satisfy our working capital requirements, to fund planned capital expenditures and to satisfy our debt service obligations will also depend upon our future operating performance, which is subject to certain risks. Please read “Item 1A. Risk Factors - Risks related to Our Business” for a discussion of such risks.

Debt Financing Activities

On February 18, 2014, we increased the maximum amount of borrowings and letters of credit under our revolving credit facility from $600.0 million to $637.5 million utilizing the accordion feature of our revolving credit facility.

On March 28, 2013, we amended and restated our revolving credit facility to (i) increase the maximum amount of borrowings and letters of credit under our revolving credit facility from $400.0 million to $600.0 million, (ii) extend the maturity date of all amounts outstanding under our revolving credit facility from April 15, 2016 to March 28, 2018, (iii) decrease the applicable interest rate margin on committed revolver loans under our revolving credit facility as described in more detail below, (iv) adjust the financial covenants as described in more detail below, (v) increase the maximum allowable amount of additional outstanding indebtedness of the borrower and us and certain of our subsidiaries as described in more detail below, and (vi) adjust the commitment fee incurred on the unused portion of the loan facility as described in more detail below.

On February 11, 2013, we completed a private placement of $250.0 million in aggregate principal amount of 7.250% senior unsecured notes due 2021 to qualified institutional buyers under Rule 144A. We received proceeds of approximately $245.1 million, after deducting initial purchasers' discounts and the expenses of the private placement. The proceeds were primarily used to repay borrowings under our revolving credit facility. On July 1, 2013, we filed a registration statement on Form S-4 with the SEC to exchange the Notes for registered 7.250% senior unsecured notes due February 2021. The exchange offer was completed on July 31, 2013.

On May 24, 2012, we redeemed $25.0 million of our senior unsecured notes from various holders using proceeds of our January 2012 follow-on equity offering, which in the interim were used to pay down amounts outstanding under our revolving credit facility. On February 28, 2014, we announced that we will exercise a full redemption of the remaining amount of the 2018 senior unsecured notes pursuant to the indenture, on or about April 1, 2014 at an aggregate redemption value of $182.8 million. We expect to fund the redemption under borrowings from our revolving credit facility.

Equity Offerings

On November 26, 2012, we completed a public offering of 3,450,000 common units at a price of $31.16 per common unit, before the payment of underwriters' discounts, commissions and offering expenses (per unit value is in dollars, not thousands). Total proceeds from the sale of the 3,450,000 common units, net of underwriters' discounts, commissions and offering expenses were $102.8 million. Our general partner contributed $2.2 million in cash to us in conjunction with the issuance in order to maintain its 2% general partner interest in us. All of the net proceeds were used to reduce our outstanding indebtedness.

On January 25, 2012, we completed a public offering of 2,645,000 common units at a price of $36.15 per common unit, before the payment of underwriters' discounts, commissions and offering expenses (per unit value is in dollars, not thousands). Total proceeds from the sale of the 2,645,000 common units, net of underwriters' discounts, commissions and offering expenses were $91.4 million. Our general partner contributed $2.0 million in cash to us in conjunction with the issuance in order to maintain its 2% general partner interest in us. All of the net proceeds were used to reduce our outstanding indebtedness.

Due to the foregoing, we believe that cash generated from operations and our borrowing capacity under our credit facility will be sufficient to meet our working capital requirements and anticipated maintenance capital expenditures in 2014.

Finally, our ability to satisfy our working capital requirements, to fund planned capital expenditures and to satisfy our debt service obligations will depend upon our future operating performance, which is subject to certain risks. Please read "Item 1A. Risk Factors - Risks Relating to Our Business" for a discussion of such risks.

Cash Flows - Twelve Months Ended December 31, 2013 Compared to Twelve Months Ended December 31, 2012

The following table details the cash flow changes between the twelve months ended December 31, 2013 and 2012:

	Twelve Months Ended December 31,		Variance	Percent Change
	2013	2012		
	(In thousands)			
Net cash provided by (used in):				
Operating activities	$112,183	$32,678	$79,505	243%
Investing activities	(186,777)	(15,036)	(171,741)	1,142%
Financing activities	85,974	(12,746)	98,720	775%
Net increase in cash and cash equivalents	$11,380	$4,896	$6,484	132%

Net cash provided by operating activities increased for the year ended December 31, 2013 primarily due to an $76.8 million favorable variance in working capital. This change resulted principally from a reduction in accounts and other receivables attributable to the timing of cash receipts from customers in our Natural Gas Services segment.

The increase in cash used in investing activities for the year ended December 31, 2013 is attributable to $275.0 million of proceeds from the 2012 sale of the Prism Assets. Additionally, 2012 includes $56.0 million of proceeds from the sale of acquired assets to Martin Resource Management. The lack of sales proceeds in 2013 was partially offset by a $150.7 million decrease in acquisition expenditures.

Net cash provided by financing activities increased for the year ended December 31, 2013 as a result of: (i) $168.0 million increase in net proceeds from long-term debt (borrowings less repayments), which includes $250.0 million from the issuance of 7.250% Senior Notes; (ii) $142.1 million of cash used in 2012 related to assets purchased from Martin Resource Management; (iii) the lack of proceeds from public offerings in 2013; and (iv) higher cash distributions and debt issuance costs of $8.1 million and $8.9 million, respectively, in 2013.

Cash Flows - Twelve Months Ended December 31, 2012 Compared to Twelve Months Ended December 31, 2011

The following table details the cash flow changes between the twelve months ended December 31, 2012 and 2011:

	Twelve Months Ended December 31,		Variance	Percent Change
	2012	2011		
	(In thousands)			

Net cash provided by (used in):				
Operating activities	$32,678	$91,362	$(58,684)	(64)%
Investing activities	(15,036)	(202,655)	187,619	(93)%
Financing activities	(12,746)	100,179	(112,925)	113%
Net increase (decrease) in cash and cash equivalents	$4,896	$(11,114)	$16,010	(144)%

Net cash provided by operating activities decreased for the year ended December 31, 2012 compared to the prior year period primarily due to a $61.6 million unfavorable variance in working capital. Working capital negatively affected cash provided by operating activities in 2012 principally due to the increase in accounts and other receivables from higher revenues in our Natural Gas Services segment. Working capital positively affected cash provided by operating activities in 2011 due to decreases in accounts and other receivables, product exchange receivables and inventories caused by price increases principally in our Natural Gas Services and Sulfur Services segments being funded through larger increases in trade and other accounts payable, product exchange payables and due to affiliates.

Net cash used in investing activities decreased for the year ended December 31, 2012 due to a $285.5 million increase in cash provided by discontinued operations resulting from the $275.0 million in proceeds from the 2012 sale of the Prism assets. In addition, investments in unconsolidated entities decreased $58.5 million in 2012. Also positively impacting 2012 was $56.0 million of proceeds from the sale of acquired assets. Partially offsetting these positive changes were increased acquisition and capital expenditures of $207.8 million and $16.4 million, respectively, in 2012.

Net cash provided by (used in) financing activities decreased for the year ended December 31, 2012 due to: (i) increased expenditures of $122.4 million related to assets purchased from Martin Resource Management; (ii) $66.0 million decrease in net proceeds from long-term debt (borrowings less repayments); (iii) $33.0 million increase in funding of investments in unconsolidated entities; and (iv) $12.0 million of increased cash distributions. Positively impacting cash flow from financing activities was an increase in proceeds from public offerings of $123.8 million.

Capital Expenditures

Our operations require continual investment to upgrade or enhance operations and to ensure compliance with safety, operational, and environmental regulations. Our capital expenditures consist primarily of:

•maintenance capital expenditures made to maintain existing assets and operations;

•expansion capital expenditures to acquire assets to grow our business, to expand existing facilities, such as projects that increase operating capacity, or to reduce operating costs; and

•plant turnaround costs made at our refinery to perform maintenance, overhaul and repair operations and to inspect, test and replace process materials and equipment.

The following table summarizes maintenance and expansion capital expenditures, excluding amounts paid for acquisitions, for the periods presented:

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2013	2012	2013	2012
	(In thousands)		(In thousands)	
Expansion capital expenditures	$26,483	$17,033	$87,601	$85,549
Maintenance capital expenditures	3,972	5,055	11,445	9,195
Plant turnaround costs	—	(471)	—	2,107
Total	$30,455	$21,617	$99,046	$96,851

Expansion capital expenditures were made primarily in our Terminalling and Storage segment during the three and twelve months ended December 31, 2013. Within our Terminalling and Storage segment, expenditures were made primarily at our Corpus Christi crude terminal, Smackover refinery, and certain smaller organic growth projects ongoing in our specialty terminalling operations. Maintenance capital expenditures were made primarily in our Terminalling and Storage, Marine Transportation, and Sulfur Services segments to maintain our existing assets and

operations during the three and twelve months ended December 31, 2013.

Expansion capital expenditures were made primarily in our Terminalling and Storage, Marine Transportation, and Sulfur Services segments during the three and twelve months ended December 31, 2012. Within our Terminalling and Storage segment, expenditures were made primarily at our Corpus Christi crude terminal and Smackover refinery. Within our Marine Transportation segment, expenditures were made to upgrade certain assets in the inland fleet. Within our Sulfur Services segment, expenditures were made to expand operations at our Neches prilling facility. Maintenance capital expenditures were made primarily in our Terminalling and Storage and Sulfur Services segments to maintain our existing assets and operations

during the three and twelve months ended December 31, 2012. For the twelve months ended December 31, 2012, plant turnaround costs include refinery turnaround expenditures at our Smackover refinery.

Capital Resources

Historically, we have generally satisfied our working capital requirements and funded our capital expenditures with cash generated from operations and borrowings. We expect our primary sources of funds for short-term liquidity will be cash flows from operations and borrowings under our credit facility.

As of December 31, 2013, we had $658.7 million of outstanding indebtedness, consisting of outstanding borrowings of $423.7 million (net of unamortized discount) in senior unsecured notes and $235.0 million under our revolving credit facility.

Total Contractual Cash Obligations. A summary of our total contractual cash obligations as of December 31, 2013, is as follows (dollars in thousands):

	Payments due by period				
Type of Obligation	Total Obligation	Less than One Year	1-3 Years	3-5 Years	Due Thereafter
Revolving credit facility	$235,000	$—	$—	$235,000	$—
2018 senior unsecured notes	173,695	—	—	173,695	—
2021 senior unsecured notes	250,000	—	—	—	250,000
Non-competition agreements	50	50	—	—	—
Throughput commitment	44,354	4,950	10,382	11,060	17,962
Operating leases	49,414	12,172	21,427	9,295	6,520
Interest expense: [1]					
Revolving credit facility	31,973	7,549	15,097	9,327	—
2018 Senior unsecured notes	67,301	15,531	31,062	20,708	—
2021 Senior unsecured notes	129,896	18,125	36,250	36,250	39,271
Total contractual cash obligations	$981,683	$58,377	$114,218	$495,335	$313,753

[1]Interest commitments are estimated using our current interest rates for the respective credit agreements over their remaining terms.

Letter of Credit. At December 31, 2013, we had outstanding irrevocable letters of credit in the amount of $0.1 million, which were issued under our revolving credit facility.

Off Balance Sheet Arrangements. We do not have any off-balance sheet financing arrangements.

Description of Our Long-Term Debt

2021 Senior Notes

We and Martin Midstream Finance Corp., a subsidiary of us (collectively, the “Issuers”), entered into (i) an Indenture, dated as of February 11, 2013 (the “2021 Indenture”) among the Issuers, certain subsidiary guarantors (the “2021 Guarantors”) and Wells Fargo Bank, National Association, as trustee (the “2021 Trustee”) and (ii) a Registration Rights Agreement, dated as of February 11, 2013 (the “2021 Registration Rights Agreement”), among the Issuers, the 2021 Guarantors and Wells Fargo Securities, LLC, RBC Capital Markets, LLC, RBS Securities Inc., SunTrust Robinson Humphrey, Inc. and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representatives of a group of initial purchasers, in connection with a private placement to eligible purchasers of $250.0 million in aggregate principal

amount of the Issuers' 7.250% senior unsecured notes due 2021 (the “2021 Notes”).

Interest and Maturity. On February 11, 2013, the Issuers issued the 2021 Notes pursuant to the 2021 Indenture in a transaction exempt from registration requirements under the Securities Act of 1933, as amended (the “Securities Act”). The 2021 Notes were resold to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to persons outside

the United States pursuant to Regulation S under the Securities Act. The 2021 Notes will mature on February 15, 2021. The interest payment dates are February 15 and August 15, beginning on August 15, 2013.

Optional Redemption. Prior to February 15, 2016, the Issuers have the option on any one or more occasions to redeem up to 35% of the aggregate principal amount of the 2021 Notes issued under the 2021 Indenture, at a redemption price of 107.250% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date of the 2021 Notes with the proceeds of certain equity offerings. Prior to February 15, 2017, the Issuers may on any one or more occasions redeem all or a part of the 2021 Notes at the redemption price equal to the sum of (i) the principal amount thereof, plus (ii) a make whole premium at the redemption date, plus accrued and unpaid interest, if any, to the redemption date. On or after February 15, 2017, the Issuers may on any one or more occasions redeem all or a part of the 2021 Notes at the redemption prices (expressed as percentages of principal amount) equal to 103.625% for the twelve-month period beginning on February 15, 2017, 101.813% for the twelve-month period beginning on February 15, 2018 and 100.00% for the twelve-month period beginning on February 15, 2019 and at any time thereafter, plus accrued and unpaid interest, if any, to the applicable redemption date on the 2021 Notes.

Certain Covenants. The 2021 Indenture restricts our ability and the ability of certain of our subsidiaries to: (i) sell assets including equity interests in our subsidiaries; (ii) pay distributions on, redeem or repurchase our units or redeem or repurchase our subordinated debt; (iii) make investments; (iv) incur or guarantee additional indebtedness or issue preferred units; (v) create or incur certain liens; (vi) enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us; (vii) consolidate, merge or transfer all or substantially all of our assets; (viii) engage in transactions with affiliates; (ix) create unrestricted subsidiaries; (x) enter into sale and leaseback transactions; or (xi) engage in certain business activities. These covenants are subject to a number of important exceptions and qualifications. If the 2021 Notes achieve an investment grade rating from each of Moody's Investors Service, Inc. and Standard & Poor's Ratings Services and no Default (as defined in the 2021 Indenture) has occurred and is continuing, many of these covenants will terminate.

Events of Default. The 2021 Indenture provides that each of the following is an Event of Default: (i) default for 30 days in the payment when due of interest on the 2021 Notes; (ii) default in payment when due of the principal of, or premium, if any, on the 2021 Notes; (iii) failure by us to comply with certain covenants relating to asset sales, repurchases of the 2021 Notes upon a change of control and mergers or consolidations; (iv) failure by us for 180 days after notice to comply with our reporting obligations under the Securities Exchange Act of 1934; (v) failure by us for 60 days after notice to comply with any of the other agreements in the 2021 Indenture; (vi) default under any mortgage, indenture or instrument governing any indebtedness for money borrowed or guaranteed by us or any of our restricted subsidiaries, whether such indebtedness or guarantee now exists or is created after the date of the 2021 Indenture, if such default: (a) is caused by a payment default; or (b) results in the acceleration of such indebtedness prior to its stated maturity, and, in each case, the principal amount of the indebtedness, together with the principal amount of any other such indebtedness under which there has been a payment default or acceleration of maturity, aggregates $20.0 million or more, subject to a cure provision; (vii) failure by us or any of our restricted subsidiaries to pay final judgments aggregating in excess of $20.0 million, which judgments are not paid, discharged or stayed for a period of 60 days; (viii) except as permitted by the 2021 Indenture, any subsidiary guarantee is held in any judicial proceeding to be unenforceable or invalid or ceases for any reason to be in full force or effect, or any 2021 Guarantor, or any person acting on behalf of any Guarantor, denies or disaffirms its obligations under its subsidiary guarantee; and (ix) certain events of bankruptcy, insolvency or reorganization described in the 2021 Indenture with respect to the Issuers or any of our restricted subsidiaries that is a significant subsidiary or any group of restricted subsidiaries that, taken together, would constitute a significant subsidiary of us. Upon a continuing Event of Default, the 2021 Trustee, by notice to the Issuers, or the holders of at least 25% in principal amount of the then outstanding 2021 Notes, by notice to the Issuers and the 2021 Trustee, may declare the 2021 Notes immediately due and payable, except that an Event of Default resulting from entry into a bankruptcy, insolvency or reorganization with respect to the Issuers, any restricted subsidiary of us that is a significant subsidiary or any group of its restricted subsidiaries that, taken together, would constitute a significant subsidiary of us, will automatically cause the 2021 Notes to become due and payable.

2021 Registration Rights Agreement. Under the 2021 Registration Rights Agreement, the Issuers and the 2021 Guarantors filed with the SEC a registration statement to exchange the 2021 Notes for substantially identical notes that are registered under the Securities Act, and completed the exchange offer on July 31, 2013.

2018 Senior Notes

The Issuers entered into (i) a Purchase Agreement, dated as of March 23, 2010 (the "2018 Purchase Agreement"), by and among the Issuers, certain subsidiary guarantors (the "2018 Guarantors") and Wells Fargo Securities, LLC, RBC Capital Markets Corporation and UBS Securities, LLC, as representatives of a group of initial purchasers (collectively, the "2018 Initial Purchasers"), (ii) an Indenture, dated as of March 26, 2010 (the "2018 Indenture"), among the Issuers, the 2018 Guarantors and

Wells Fargo Bank, National Association, as trustee (the "2018 Trustee") and (iii) a Registration Rights Agreement, dated as of March 26, 2010 (the "2018 Registration Rights Agreement"), among the Issuers, the 2018 Guarantors and the 2018 Initial Purchasers, in connection with a private placement to eligible purchasers of $200 million in aggregate principal amount of the Issuers' 8.875% senior unsecured notes due 2018 (the "2018 Notes"). We completed the aforementioned 2018 Notes offering on March 26, 2010 and received proceeds of approximately $197.2 million, after deducting initial purchaser discounts and the expenses of the private placement. The proceeds were primarily used to repay borrowings under our revolving credit facility.

2018 Indenture

Interest and Maturity. On March 26, 2010, the Issuers issued the 2018 Notes pursuant to the 2018 Indenture in a transaction exempt from registration requirements under the Securities Act. The 2018 Notes were resold to qualified institutional buyers pursuant to Rule 144A under the Securities Act and to persons outside the U.S. pursuant to Regulation S under the Securities Act. The 2018 Notes will mature on April 1, 2018. The interest payment dates are April 1 and October 1.

Optional Redemption. Prior to April 1, 2013, the Issuers have the option on any one or more occasions to redeem up to 35% of the aggregate principal amount of the 2018 Notes issued under the 2018 Indenture at a redemption price of 108.875% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date of the 2018 Notes with the proceeds of certain equity offerings. Prior to April 1, 2014, the Issuers may on any one or more occasions redeem all or a part of the 2018 Notes at the redemption price equal to the sum of (i) the principal amount thereof, plus (ii) a make whole premium at the redemption date, plus accrued and unpaid interest, if any, to the redemption date. On or after April 1, 2014, the Issuers may on any one or more occasions redeem all or a part of the 2018 Notes at redemption prices (expressed as percentages of principal amount) equal to 104.438% for the twelve-month period beginning on April 1, 2014, 102.219% for the 12-month period beginning on April 1, 2015 and 100.00% for the 12-month period beginning on April 1, 2016, and at any time thereafter, plus accrued and unpaid interest, if any, to the applicable redemption date on the 2018 Notes.

On April 24, 2012 we notified the 2018 Trustee of our intention to exercise a partial redemption of the our 2018 Notes pursuant to the 2018 Indenture. On May 24, 2012, we redeemed $25.0 million of the 2018 Notes from various holders using proceeds of our January 2012 follow-on equity offering, which in the interim were used to pay down amounts outstanding under our revolving credit facility. On February 28, 2014, we announced that we will exercise a full redemption of the 2018 senior unsecured notes pursuant to the indenture, on or about April 1, 2014 at an aggregate redemption value of $182.8 million. We expect to fund the redemption under borrowings from our revolving credit facility.

Certain Covenants. The 2018 Indenture restricts our ability and the ability of certain of our subsidiaries to: (i) sell assets including equity interests in its subsidiaries; (ii) pay distributions on, redeem or repurchase its units or redeem or repurchase its subordinated debt; (iii) make investments; (iv) incur or guarantee additional indebtedness or issue preferred units; (v) create or incur certain liens; (vi) enter into agreements that restrict distributions or other payments from its restricted subsidiaries to us; (vii) consolidate, merge or transfer all or substantially all of its assets; (viii) engage in transactions with affiliates; (ix) create unrestricted subsidiaries; (x) enter into sale and leaseback transactions; or (xi) engage in certain business activities. These covenants are subject to a number of important exceptions and qualifications. If the 2018 Notes achieve an investment grade rating from each of Moody's Investors Service, Inc. and Standard & Poor's Ratings Services and no Default (as defined in the 2018 Indenture) has occurred and is continuing, many of these covenants will terminate.

Events of Default. The 2018 Indenture provides that each of the following is an Event of Default: (i) default for 30 days in the payment when due of interest on the 2018 Notes; (ii) default in payment when due of the principal of, or premium, if any, on the 2018 Notes; (iii) our failure to comply with certain covenants relating to asset sales,

repurchases of the 2018 Notes upon a change of control and mergers or consolidations; (iv) our failure, for 180 days after notice, to comply with its reporting obligations under the Securities Exchange Act of 1934; (v) our failure, for 60 days after notice, to comply with any of the other agreements in the 2018 Indenture; (vi) default under any mortgage, indenture or instrument governing any indebtedness for money borrowed or guaranteed by us or any of our restricted subsidiaries, whether such indebtedness or guarantee now exists or is created after the date of the 2018 Indenture, if such default: (a) is caused by a payment default; or (b) results in the acceleration of such indebtedness prior to its stated maturity, and, in each case, the principal amount of the indebtedness, together with the principal amount of any other such indebtedness under which there has been a payment default or acceleration of maturity, aggregates $20 million or more, subject to a cure provision; (vii) our or any of our restricted subsidiaries failure to pay final judgments aggregating in excess of $20 million, which judgments are not paid, discharged or stayed for a period of 60 days; (viii) except as permitted by the 2018 Indenture, any subsidiary guarantee is held in any judicial proceeding to be unenforceable or invalid or ceases for any reason to be in full force or effect, or any Guarantor, or any person acting on behalf of any Guarantor, denies or disaffirms its obligations under its subsidiary guarantee; and (ix) certain events of bankruptcy, insolvency or reorganization described in the 2018 Indenture with respect to the Issuers or any of our restricted subsidiaries that is a significant subsidiary or any group of restricted subsidiaries that, taken together, would constitute a

significant subsidiary of us. Upon a continuing Event of Default, the 2018 Trustee, by notice to the Issuers, or the holders of at least 25% in principal amount of the then outstanding 2018 Notes, by notice to the Issuers and the 2018 Trustee, may declare the 2018 Notes immediately due and payable, except that an Event of Default resulting from entry into a bankruptcy, insolvency or reorganization with respect to the Issuers, any restricted subsidiary of us that is a significant subsidiary or any group of its restricted subsidiaries that, taken together, would constitute a significant subsidiary of us, will automatically cause the 2018 Notes to become due and payable.

2018 Registration Rights Agreement. Under the 2018 Registration Rights Agreement, the Issuers and the 2018 Guarantors filed with the SEC a registration statement to exchange the 2018 Notes for substantially identical notes that are registered under the Securities Act. We exchanged the 2018 Notes for registered 8.875% senior unsecured notes due April 2018.

Revolving Credit Facility

On November 10, 2005, we entered into a $225.0 million multi-bank credit facility, which has subsequently been amended multiple times. On March 28, 2013, we amended and restated our credit facility to (i) increase the maximum amount of borrowings and letters of credit under the credit facility from $400.0 million to $600.0 million, (ii) extend the maturity date of all amounts outstanding under the credit facility from April 15, 2016 to March 28, 2018, (iii) decrease the applicable interest rate margin on committed revolver loans under the credit facility as described in more detail below, (iv) adjust the financial covenants as described in more detail below, (v) increase the maximum allowable amount of additional outstanding indebtedness of the borrower and us and certain of its subsidiaries as described in more detail below, and (vi) adjust the commitment fee incurred on the unused portion of the loan facility as described in more detail below. The most recent amendment to our revolving credit facility occurred on February 18, 2014 when we increased our maximum amount of borrowings to $637.5 million utilizing the accordion feature of our revolving credit facility.

As of December 31, 2013, we had $235.0 million outstanding under the revolving credit facility and $0.1 million of letters of credit issued, leaving a maximum available to be borrowed under our credit facility for future revolving credit borrowings and letters of credit of $364.9 million. Subject to the financial covenants contained in our credit facility and based on our existing EBITDA (as defined in our credit facility) calculations, as of December 31, 2013, we have the ability to incur approximately $83.6 million of that amount.

The revolving credit facility is used for ongoing working capital needs and general partnership purposes, and to finance permitted investments, acquisitions and capital expenditures. During the year ended December 31, 2013, the level of outstanding draws on our credit facility has ranged from a low of $40.0 million to a high of $298.0 million.

The credit facility is guaranteed by substantially all of our subsidiaries. Obligations under the credit facility are secured by first priority liens on substantially all of our assets and those of the guarantors, including, without limitation, inventory, accounts receivable, bank accounts, marine vessels, equipment, fixed assets and the interests in our subsidiaries and certain of our equity method investees.

We may prepay all amounts outstanding under the credit facility at any time without premium or penalty (other than customary LIBOR breakage costs), subject to certain notice requirements. The credit facility requires mandatory prepayments of amounts outstanding thereunder with the net proceeds of certain asset sales, equity issuances and debt incurrences.

Indebtedness under the credit facility bears interest at our option at the Eurodollar Rate (the British Bankers Association LIBOR Rate) plus an applicable margin or the Base Rate (the highest of the Federal Funds Rate plus 0.50%, the 30-day Eurodollar Rate plus 1.0%, or the administrative agent’s prime rate) plus an applicable margin. We pay a per annum fee on all letters of credit issued under the credit facility, and we pay a commitment fee per annum on

the unused revolving credit availability under the credit facility. The letter of credit fee, the commitment fee and the applicable margins for our interest rate vary quarterly based on our leverage ratio (as defined in the credit facility, being generally computed as the ratio of total funded debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges) and are as follows:

Leverage Ratio	Base Rate Loans	Eurodollar Rate Loans	Letters of Credit
Less than 3.00 to 1.00	1.00 %	2.00 %	2.00 %
Greater than or equal to 3.00 to 1.00 and less than 3.50 to 1.00	1.25 %	2.25 %	2.25 %
Greater than or equal to 3.50 to 1.00 and less than 4.00 to 1.00	1.50 %	2.50 %	2.50 %
Greater than or equal to 4.00 to 1.00 and less than 4.50 to 1.00	1.75 %	2.75 %	2.75 %
Greater than or equal to 4.50 to 1.00	2.00 %	3.00 %	3.00 %

The applicable margin for revolving loans that are LIBOR loans ranges from 2.00% to 3.00% and the applicable margin for revolving loans that are base prime rate loans ranges from 1.00% to 2.00%. The applicable margin for LIBOR borrowings at December 31, 2013 is 3.00%.

The credit facility includes financial covenants that are tested on a quarterly basis, based on the rolling four-quarter period that ends on the last day of each fiscal quarter. The maximum permitted leverage ratio is 5.25 to 1.00. The maximum permitted senior leverage ratio (as defined in the credit facility but generally computed as the ratio of total secured funded debt to consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges) is 3.50 to 1.00. The minimum interest coverage ratio (as defined in the credit facility but generally computed as the ratio of consolidated earnings before interest, taxes, depreciation, amortization and certain other non-cash charges to consolidated interest charges) is 2.50 to 1.00.

In addition, the credit facility contains various covenants, which, among other things, limit our and our subsidiaries' ability to: (i) grant or assume liens; (ii) make investments (including investments in our joint ventures) and acquisitions; (iii) enter into certain types of hedging agreements; (iv) incur or assume indebtedness; (v) sell, transfer, assign or convey assets; (vi) repurchase our equity, make distributions and certain other restricted payments, but the credit facility permits us to make quarterly distributions to unitholders so long as no default or event of default exists under the credit facility; (vii) change the nature of our business; (viii) engage in transactions with affiliates; (ix) enter into certain burdensome agreements; (x) make certain amendments to the Omnibus Agreement and our material agreements; (xi) make capital expenditures; and (xii) permit our joint ventures to incur indebtedness or grant certain liens.

The credit facility contains customary events of default, including, without limitation, (i) failure to pay any principal, interest, fees, expenses or other amounts when due; (ii) failure to meet the quarterly financial covenants; (iii) failure to observe any other agreement, obligation, or covenant in the credit facility or any related loan document, subject to cure periods for certain failures; (iv) the failure of any representation or warranty to be materially true and correct when made; (v) our or any of our subsidiaries' default under other indebtedness that exceeds a threshold amount; (vi) bankruptcy or other insolvency events involving us or any of our subsidiaries; (vii) judgments against us or any of our subsidiaries, in excess of a threshold amount; (viii) certain ERISA events involving us or any of our subsidiaries, in excess of a threshold amount; (ix) a change in control (as defined in the credit facility); and (x) the invalidity of any of the loan documents or the failure of any of the collateral documents to create a lien on the collateral.

The credit facility also contains certain default provisions relating to Martin Resource Management. If Martin Resource Management no longer controls our general partner, the lenders under the credit facility may declare all amounts outstanding thereunder immediately due and payable. In addition, an event of default by Martin Resource Management under its credit facility could independently result in an event of default under our credit facility if it is deemed to have a material adverse effect on us.

If an event of default relating to bankruptcy or other insolvency events occurs with respect to us or any of our subsidiaries, all indebtedness under our credit facility will immediately become due and payable. If any other event of default exists under our credit facility, the lenders may terminate their commitments to lend us money, accelerate the

maturity of the indebtedness outstanding under the credit facility and exercise other rights and remedies. In addition, if any event of default exists under our credit facility, the lenders may commence foreclosure or other actions against the collateral.

As of March 3, 2014, our outstanding indebtedness includes $240.0 million under our credit facility.

We are subject to interest rate risk on our credit facility due to the variable interest rate and may enter into interest rate swaps to reduce this variable rate risk.

Seasonality

A substantial portion of our revenues are dependent on sales prices of products, particularly NGLs and fertilizers, which fluctuate in part based on winter and spring weather conditions. The demand for NGLs is strongest during the winter heating season and the refinery blending season. The demand for fertilizers is strongest during the early spring planting season. However, our Terminalling and Storage and Marine Transportation segments and the molten sulfur business are typically not impacted by seasonal fluctuations. A significant portion of our net income is derived from our terminalling and storage, sulfur and marine transportation businesses. Therefore, we do not expect that our overall net income will be impacted by seasonality factors. However, extraordinary weather events, such as hurricanes, have in the past, and could in the future, impact our Terminalling and Storage and Marine Transportation segments.

Impact of Inflation

Inflation did not have a material impact on our results of operations in 2013, 2012 or 2011. Although the impact of inflation has been insignificant in recent years, it is still a factor in the U.S. economy and may increase the cost to acquire or replace property, plant and equipment. It may also increase the costs of labor and supplies. In the future, increasing energy prices could adversely affect our results of operations. Diesel fuel, natural gas, chemicals and other supplies are recorded in operating expenses. An increase in price of these products would increase our operating expenses which could adversely affect net income. We cannot provide assurance that we will be able to pass along increased operating expenses to our customers.

Environmental Matters

Our operations are subject to environmental laws and regulations adopted by various governmental authorities in the jurisdictions in which these operations are conducted. We incurred no material environmental costs, liabilities or expenditures to mitigate or eliminate environmental contamination during 2013, 2012 or 2011.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Interest Rate Risk. We are exposed to changes in interest rates as a result of our credit facility, which had a weighted-average interest rate of 3.21% as of December 31, 2013. As of March 3, 2014, we had total indebtedness outstanding under our credit facility of $240.0 million, all of which was unhedged floating rate debt. Based on the amount of unhedged floating rate debt owed by us on December 31, 2013, the impact of a 1% increase in interest rates on this amount of debt would result in an increase in interest expense and a corresponding decrease in net income of approximately $2.4 million annually.

We are not exposed to changes in interest rates with respect to our senior unsecured notes as these obligations are fixed rate. The estimated fair value of the senior unsecured notes was approximately $443.8 million as of December 31, 2013, based on market prices of similar debt at December 31, 2013. Market risk is estimated as the potential decrease in fair value of our long-term debt resulting from a hypothetical increase of 1% in interest rates. Such an increase in interest rates would result in approximately an $14.2 million decrease in fair value of our long-term debt at December 31, 2013.

Item 8. Financial Statements and Supplementary Data

The following financial statements of Martin Midstream Partners L.P. (Partnership) are listed below:

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Consolidated Balance Sheets as of December 31, 2013 and 2012	73
Consolidated Statements of Operations for the years ended December 31, 2013, 2012 and 2011	74
Consolidated Statements of Comprehensive Income for the years ended December 31, 2013, 2012 and 2011	77
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Report of Independent Registered Public Accounting Firm

The Board of Directors
Martin Midstream GP LLC:

We have audited the accompanying consolidated balance sheets of Martin Midstream Partners L.P. and subsidiaries as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income, changes in capital, and cash flows for each of the years in the three-year period ended December 31, 2013. These financial statements are the responsibility of Martin Midstream'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 (U.S.). 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 consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Martin Midstream Partners L.P. and subsidiaries as of December 31, 2013 and 2012 and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2013, 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 (U.S.), Martin Midstream Partners L.P. and subsidiaries' internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control—Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 3, 2014 expressed an unqualified opinion on the effectiveness of Martin Midstream Partners L.P. and subsidiaries' internal control over financial reporting.

/s/ KPMG LLP

Dallas, Texas
March 3, 2014

Report of Independent Registered Public Accounting Firm on Internal Controls

The Board of Directors
Martin Midstream GP LLC:

We have audited Martin Midstream Partners L.P. and subsidiaries' internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control—Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Martin Midstream's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting in Item 9A(b). Our responsibility is to express an opinion on Martin Midstream's internal control over financial reporting based on our audit.

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

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

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

In our opinion, Martin Midstream Partners L.P. and subsidiaries maintained, in all respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control – Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (U.S.), the consolidated balance sheets of Martin Midstream Partners L.P. and subsidiaries as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income, changes in capital, and cash flows for each of the years in the three-year period ended December 31, 2013, and our report dated March 3, 2013 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Dallas, Texas
March 3, 2014

MARTIN MIDSTREAM PARTNERS L.P.
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)

	December 31, 2013	2012
Assets		
Cash	$16,542	$5,162
Accounts and other receivables, less allowance for doubtful accounts of $2,492 and $2,805, respectively	163,855	190,652
Product exchange receivables	2,727	3,416
Inventories	94,902	95,987
Due from affiliates	12,099	13,343
Other current assets	7,353	2,777
Assets held for sale	—	3,578
Total current assets	297,478	314,915
Property, plant and equipment, at cost	929,183	767,344
Accumulated depreciation	(304,808)	(256,963)
Property, plant and equipment, net	624,375	510,381
Goodwill	23,802	19,616
Investment in unconsolidated entities	128,662	154,309
Debt issuance costs, net	15,659	10,244
Other assets, net	7,943	3,531
	$1,097,919	$1,012,996
Liabilities and Partners' Capital		
Current portion of long-term debt and capital lease obligations	$—	$3,206
Trade and other accounts payable	142,951	140,045
Product exchange payables	9,595	12,187
Due to affiliates	2,596	3,316
Income taxes payable	1,204	10,239
Other accrued liabilities	20,242	9,489
Total current liabilities	176,588	178,482
Long-term debt and capital leases, less current maturities	658,695	474,992
Other long-term obligations	2,219	1,560
Total liabilities	837,502	655,034
Commitments and contingencies		
Partners' capital	260,417	357,962
	$1,097,919	$1,012,996

See accompanying notes to consolidated financial statements.

MARTIN MIDSTREAM PARTNERS L.P.
CONSOLIDATED STATEMENTS OF OPERATIONS
(Dollars in thousands, except per unit amounts)

	Year Ended December 31,		
	2013	2012	2011
Revenues:			
Terminalling and storage *	$115,965	$90,243	$77,283
Marine transportation *	98,523	85,748	76,936
Sulfur services *	12,004	11,702	11,400
Product sales: *			
Natural gas services	984,653	825,506	611,749
Sulfur services	201,120	249,882	263,644
Terminalling and storage	221,245	227,280	201,478
	1,407,018	1,302,668	1,076,871
Total revenues	1,633,510	1,490,361	1,242,490
Costs and expenses:			
Cost of products sold: (excluding depreciation and amortization)			
Natural gas services *	944,961	801,724	598,814
Sulfur services *	157,723	194,952	219,697
Terminalling and storage *	195,640	205,588	182,412
	1,298,324	1,202,264	1,000,923
Expenses:			
Operating expenses *	172,043	146,287	134,734
Selling, general and administrative *	29,397	25,494	20,531
Depreciation and amortization	52,240	42,063	40,276
Total costs and expenses	1,552,004	1,416,108	1,196,464
Other operating income (loss)	1,166	(418)	1,326
Operating income	82,672	73,835	47,352
Other income (expense):			
Equity in loss of unconsolidated entities	(53,048)	(1,113)	(4,752)
Debt prepayment premium	(272)	(2,470)	—
Interest expense	(42,495)	(30,665)	(26,781)
Other, net	542	1,092	420
Total other income (expense)	(95,273)	(33,156)	(31,113)
Net income (loss) before taxes	(12,601)	40,679	16,239
Income tax expense	(753)	(3,557)	(2,872)
Income (loss) from continuing operations	(13,354)	37,122	13,367
Income from discontinued operations, net of income taxes	—	64,865	9,392
Net income (loss)	(13,354)	101,987	22,759
Less general partner's interest in net (income) loss	267	(4,748)	(5,289)
Less pre-acquisition (income) loss allocated to Parent	—	(4,622)	1,583
Less (income) loss allocable to unvested restricted units	40	—	—
Less beneficial conversion feature	—	—	(1,108)
Limited partner's interest in net income	$(13,047)	$92,617	$17,945

*Related Party Transactions Shown Below

See accompanying notes to consolidated financial statements.

MARTIN MIDSTREAM PARTNERS L.P.
CONSOLIDATED STATEMENTS OF OPERATIONS
(Dollars in thousands, except per unit amounts)

*Related Party Transactions Included Above

	Year Ended December 31,		
	2013	2012	2011
Revenues:			
Terminalling and storage	$71,517	$64,669	$54,211
Marine transportation	24,654	17,494	23,478
Product sales	4,698	7,201	9,081
Costs and expenses:			
Cost of products sold: (excluding depreciation and amortization)			
Natural gas services	32,639	27,512	16,749
Sulfur services	18,161	16,968	18,314
Terminalling and storage	48,868	48,375	45,089
Expenses:			
Operating expenses	70,333	58,834	58,051
Selling, general and administrative	17,733	13,678	8,610

See accompanying notes to consolidated financial statements.

MARTIN MIDSTREAM PARTNERS L.P.
CONSOLIDATED STATEMENTS OF OPERATIONS
(Dollars in thousands, except per unit amounts)

	Year Ended December 31,		
	2013	2012	2011
Allocation of net income (loss) attributable to:			
Limited partner interest:			
Continuing operations	$(13,047)	$30,915	$11,193
Discontinued operations	—	61,702	6,752
	(13,047)	92,617	17,945
General partner interest:			
Continuing operations	(267)	1,585	3,106
Discontinued operations	—	3,163	2,183
	(267)	4,748	5,289
Net income (loss) per unit attributable to limited partners:			
Basic:			
Continuing operations	$(0.49)	$1.32	$0.57
Discontinued operations	—	2.64	0.35
	$(0.49)	$3.96	$0.92
Weighted average limited partner units - basic	26,558	23,362	19,545
Diluted:			
Continuing operations	$(0.49)	$1.32	$0.57
Discontinued operations	—	2.64	0.35
	$(0.49)	$3.96	$0.92
Weighted average limited partner units - diluted	26,558	23,365	19,547

See accompanying notes to consolidated financial statements.

MARTIN MIDSTREAM PARTNERS L.P.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Dollars in thousands)

	Year Ended December 31,		
	2013	2012	2011
Net income (loss)	$(13,354)	$101,987	$22,759
Other comprehensive income adjustments:			
Changes in fair values of commodity cash flow hedges	—	126	1,011
Commodity cash flow hedging gains reclassified to earnings	—	(752)	(1,822)
Interest rate cash flow hedging losses reclassified to earnings	—	—	18
Other comprehensive loss	—	(626)	(793)
Comprehensive income (loss)	$(13,354)	$101,361	$21,966

See accompanying notes to consolidated financial statements.

MARTIN MIDSTREAM PARTNERS L.P.
CONSOLIDATED STATEMENTS OF CHANGES IN CAPITAL
(Dollars in thousands)

	Partners' Capital							
	Parent Net Investment	Common Units	Amount	Subordinated Units	Amount	General Partner Amount	Accumulated Comprehensive Income Amount	Total
Balances – December 31, 2010	$53,154	17,707,832	$250,787	889,444	$17,721	$4,879	$1,419	$327,960
Net income (loss)	(1,583)	—	19,053	—	—	5,289	—	22,759
Recognition of beneficial conversion feature	—	—	(1,108)	—	1,108	—	—	—
Follow-on public offering	—	1,874,500	70,330	—	—	—	—	70,330
Issuance of restricted units	—	14,850	—	—	—	—	—	—
General partner contribution	—	—	—	—	—	1,505	—	1,505
Conversion of subordinated units to common units	—	889,444	18,829	(889,444)	(18,829)	—	—	—
Cash distributions ($3.05 per unit)	—	—	(58,252)	—	—	(6,245)	—	(64,497)
Excess purchase price over carrying value of acquired assets	—	—	(19,685)	—	—	—	—	(19,685)
Unit-based compensation	—	—	190	—	—	—	—	190
Purchase of treasury units	—	(14,850)	(582)	—	—	—	—	(582)
Adjustment in fair value of derivatives	—	—	—	—	—	—	(793)	(793)
Balances – December 31, 2011	51,571	20,471,776	279,562	—	—	5,428	626	337,187
Net income	4,622		92,617			4,748		101,987
Follow-on public offering	—	6,095,000	194,170	—	—	—	—	194,170
Issuance of restricted units	—	6,250	—	—	—	—	—	—
General partner contribution	—	—	—	—	—	4,145	—	4,145
Cash distributions ($3.06 per unit)	—	—	(70,679)	—	—	(5,849)	—	(76,528)
Excess purchase price over carrying value of	—	—	(142,075)	—	—	—	—	(142,075)

acquired assets								
Excess carrying value of assets over the purchase price paid by Martin Resource Management	—	—	(4,268)	—	—	—	—	(4,268)
Unit-based compensation	—	—	385	—	—	—	—	385
Purchase of treasury units	—	(6,250)	(222)	—	—	—	—	(222)
Contributions to parent	(56,193)	—	—	—	—	—	—	(56,193)
Adjustment in fair value of derivatives	—	—	—	—	—	—	(626)	(626)
Balances – December 31, 2012	—	26,566,776	349,490	—	—	8,472	—	357,962
Net loss	—	—	(13,087)	—	—	(267)	—	(13,354)
Issuance of restricted units	—	64,500	—	—	—	—	—	—
Forfeiture of restricted units	—	(250)	—	—	—	—	—	—
General partner contribution	—	—	—	—	—	37	—	37
Purchase of treasury units	—	(6,000)	(250)	—	—	—	—	(250)
Cash distributions ($3.11 per unit)	—	—	(82,735)	—	—	(1,853)	—	(84,588)
Excess purchase price over carrying value of acquired assets	—	—	(301)	—	—	—	—	(301)
Unit-based compensation	—	—	911	—	—	—	—	911
Balances – December 31, 2013	$—	26,625,026	$254,028	—	$—	$6,389	$—	$260,417

See accompanying notes to consolidated financial statements.

MARTIN MIDSTREAM PARTNERS L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in thousands)

	Year Ended December 31,		
	2013	2012	2011
Cash flows from operating activities:			
Net income (loss)	$(13,354)	$101,987	$22,759
Less: Income from discontinued operations	—	(64,865)	(9,392)
Net income (loss) from continuing operations	(13,354)	37,122	13,367
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	52,240	42,063	40,276
Amortization of deferred debt issue costs	3,700	3,290	3,755
Amortization of discount on notes payable	306	581	351
Deferred income taxes	—	402	622
(Gain) loss on disposition or sale of property, plant, and equipment	(217)	795	898
Gain on sale of equity method investment	(750)	(486)	—
Equity in loss of unconsolidated entities	53,048	1,113	4,752
Unit-based compensation	911	385	190
Preferred dividends on Martin Energy Trading	1,738	—	—
Other	6	—	—
Change in current assets and liabilities, excluding effects of acquisitions and dispositions:			
Accounts and other receivables	23,847	(56,856)	(34,626)
Product exchange receivables	689	14,230	(8,547)
Inventories	3,762	(2,733)	(28,714)
Due from affiliates	1,244	(20,135)	5,551
Other current assets	(5,432)	3,046	(1,996)
Trade and other accounts payable	(6,019)	17,595	50,904
Product exchange payables	(2,592)	(25,126)	14,961
Due to affiliates	(1,203)	18,976	11,874
Income taxes payable	(357)	367	(943)
Other accrued liabilities	10,753	(1,463)	1,063
Change in other non-current assets and liabilities	(1,459)	872	3,500
Net cash provided by continuing operating activities	120,861	34,038	77,238
Net cash provided by (used in) discontinued operating activities	(8,678)	(1,360)	14,124
Net cash provided by operating activities	112,183	32,678	91,362
Cash flows from investing activities:			
Payments for property, plant, and equipment	(92,243)	(93,640)	(77,202)
Acquisitions, net of cash acquired	(73,921)	(224,603)	(16,815)
Proceeds from sale of acquired assets	—	56,000	—
Payments for plant turnaround costs	—	(2,107)	(2,103)
Proceeds from sale of property, plant, and equipment	5,576	44	1,025
Proceeds from sale of equity method investment	750	531	—
Proceeds from involuntary conversion of property, plant and equipment	2,200	—	—
Investments in unconsolidated entities	—	(775)	(59,319)
Milestone distributions from ECP	—	2,208	—
Return of investments from unconsolidated entities	1,738	5,980	1,432
Contributions to unconsolidated entities for operations	(30,877)	(30,279)	(35,765)

Net cash used in continuing investing activities	(186,777)	(286,641)	(188,747)
Net cash provided by (used in) discontinued investing activities	—	271,605	(13,908)
Net cash used in investing activities	(186,777)	(15,036)	(202,655)
Cash flows from financing activities:			
Payments of long-term debt	(650,000)	(706,000)	(442,000)
Payments of notes payable and capital lease obligations	(8,809)	(6,556)	(1,132)
Proceeds from long-term debt	839,000	727,000	529,000
Net proceeds from follow on public offerings	—	194,170	70,330
General partner contributions	37	4,145	1,505
Excess purchase price over carrying value of acquired assets	(301)	(142,075)	(19,685)
Excess carrying value of assets over the purchase price paid by Martin Resource Management	—	(4,268)	—
Purchase of treasury units	(250)	(222)	(582)
Increase (decrease) in affiliate funding of investments in unconsolidated entities	—	(2,208)	30,828
Payments of debt issuance costs	(9,115)	(204)	(3,588)
Cash distributions paid	(84,588)	(76,528)	(64,497)
Net cash provided by (used in) financing activities	85,974	(12,746)	100,179
Net increase (decrease) in cash	11,380	4,896	(11,114)
Cash at beginning of period	5,162	266	11,380
Cash at end of period	$16,542	$5,162	$266

See accompanying notes to consolidated financial statements.

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in thousands, except where otherwise indicated)

(1) Organization and Description of Business

Martin Midstream Partners L.P. (the "Partnership") is a publicly traded limited partnership with a diverse set of operations focused primarily in the United States "U.S." Gulf Coast region. Its four primary business lines include: terminalling and storage services for petroleum products and by-products including the refining, blending and packaging of finished lubricants; natural gas services, including liquids distribution services and natural gas storage; sulfur and sulfur-based products processing, manufacturing, marketing and distribution; and marine transportation services for petroleum products and by-products.

The petroleum products and by-products the Partnership collects, transports, stores and distributes are produced primarily by major and independent oil and gas companies who often turn to third parties, such as the Partnership, for the transportation and disposition of these products. In addition to these major and independent oil and gas companies, the Partnership's primary customers include independent refiners, large chemical companies, fertilizer manufacturers and other wholesale purchasers of these products. The Partnership operates primarily in the U.S. Gulf Coast region, which is a major hub for petroleum refining, natural gas gathering and processing and support services for the oil and gas exploration and production industry.

In 2011, the Partnership and Martin Resource Management Corporation ("Martin Resource Management" or "Parent") formed Redbird Gas Storage LLC ("Redbird"), a natural gas storage joint venture to invest in Cardinal Gas Storage Partners LLC ("Cardinal"). Cardinal is a joint venture between Redbird and Energy Capital Partners ("ECP") that is focused on the development, construction, operation and management of natural gas storage facilities across northern Louisiana and Mississippi. The Partnership now owns 100% of the Class A and Class B equity interests in Redbird. As of December 31, 2013 and 2012, Redbird owned an unconsolidated 42.21% and 41.28% interest in Cardinal, respectively. This investment is accounted for by the equity method.

On August 30, 2013, Martin Resource Management completed the sale of a 49% non-controlling voting interest (50% economic interest) in MMGP Holdings, LLC ("Holdings"), a newly-formed sole member of Martin Midstream GP LLC ("MMGP"), the general partner of the Partnership, to certain affiliated investment funds managed by Alinda Capital Partners ("Alinda"). Upon closing the transaction, Alinda appointed two representatives to serve on the board of directors of the general partner of the Partnership.

(2) Significant Accounting Policies

(a) Principles of Presentation and Consolidation

The consolidated financial statements include the financial statements of the Partnership and its wholly-owned subsidiaries and equity method investees. In the opinion of the management of the Partnership's general partner, all adjustments and elimination of significant intercompany balances necessary for a fair presentation of the Partnership's results of operations, financial position and cash flows for the periods shown have been made. All such adjustments are of a normal recurring nature. In addition, the Partnership evaluates its relationships with other entities to identify whether they are variable interest entities under certain provisions of the Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC"), 810-10 and to assess whether it is the primary beneficiary of such entities. If the determination is made that the Partnership is the primary beneficiary, then that entity is included in the consolidated financial statements in accordance with ASC 810-10. No such variable interest entities exist as of December 31, 2013 or 2012.

As discussed in Note 5, on July 31, 2012, the Partnership completed the sale of its East Texas and Northwest Louisiana natural gas gathering and processing assets. These assets, along with additional gathering and processing assets discussed in Note 5 are collectively referred to as the “Prism Assets.” The Partnership has presented the results of operations and cash flows of the Prism Assets as discontinued operations for the years ended December 31, 2012 and 2011.

On October 2, 2012, the Partnership, which owned 10.74% of the Class A interests and 100% of the Class B interests, acquired all of the remaining Class A interests in Redbird from Martin Underground Storage, Inc. (“MUS”), a subsidiary of Martin Resource Management. Redbird was formed by the Partnership and Martin Resource Management in 2011 to invest in Cardinal.

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in thousands, except where otherwise indicated)

On October 2, 2012, the Partnership acquired from Cross Oil Refining and Marketing, Inc. (“Cross”), a wholly-owned subsidiary of Martin Resource Management, certain specialty lubricant product blending and packaging assets (“Blending and Packaging Assets”).

The acquisitions of the Redbird Class A interests and the Blending and Packaging Assets were considered a transfer of net assets between entities under common control. The acquisitions of the Redbird Class A interests and the Blending and Packaging Assets are recorded at amounts based on the historical carrying value of these assets at October 2, 2012, and the Partnership is required to update its historical financial statements to include the activities of the Redbird Class A interests and the Blending and Packaging Assets as of the date of common control. The Partnership’s accompanying historical financial statements have been retrospectively updated to reflect the effects on financial position, cash flows and results of operations attributable to the activities of the Redbird Class A interests and the Blending and Packaging Assets as if the Partnership owned these assets for the periods presented. Net income attributable to the Redbird Class A interests and the activities of the Blending and Packaging Assets for periods prior to the Partnership’s acquisition of the assets is not allocated to the general and limited partners for purposes of calculating net income per limited partner unit. See Note 16.

Certain expense reclassifications were made to the Partnership's Consolidated Statements of Operations for the years ended December 31, 2012 and 2011 in order to conform to the current presentation.

(b) Product Exchanges

The Partnership enters into product exchange agreements with third parties, whereby the Partnership agrees to exchange natural gas liquids (“NGLs”) and sulfur with third parties. The Partnership records the balance of exchange products due to other companies under these agreements at quoted market product prices and the balance of exchange products due from other companies at the lower of cost or market. Cost is determined using the first-in, first-out (“FIFO”) method. Product exchanges with the same counterparty are entered into in contemplation of one another and are combined. The net amount related to location differentials is reported in “Product sales” or “Cost of products sold” in the Consolidated Statements of Operations.

(c) Inventories

Inventories are stated at the lower of cost or market. Cost is determined by using the FIFO method for all inventories except lubricants and lubricants packaging inventories. Lubricants and lubricants packaging inventories cost is determined using standard cost, which approximates actual cost, computed on a FIFO basis.

(d) Revenue Recognition

Terminalling and Storage – Revenue is recognized for storage contracts based on the contracted monthly tank fixed fee. For throughput contracts, revenue is recognized based on the volume moved through the Partnership’s terminals at the contracted rate. For the Partnership’s tolling agreement, revenue is recognized based on the contracted monthly reservation fee and throughput volumes moved through the facility. When lubricants and drilling fluids are sold by truck or rail, revenue is recognized upon delivering product to the customers as title to the product transfers when the customer physically receives the product.

Natural Gas Services – NGL distribution revenue is recognized when product is delivered by truck to the Partnership's NGL customers, which occurs when the customer physically receives the product. When product is sold in storage, or by pipeline, the Partnership recognizes NGL distribution revenue when the customer receives the product from either

the storage facility or pipeline.

Sulfur Services – Revenue from sulfur product sales is recognized when the customer takes title to the product. Revenue from sulfur services is recognized as deliveries are made during each monthly period.

Marine Transportation – Revenue is recognized for time charters based on a per day rate. For contracted trips, revenue is recognized upon completion of the particular trip.

(e) Equity Method Investments

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in thousands, except where otherwise indicated)

The Partnership uses the equity method of accounting for investments in unconsolidated entities where the ability to exercise significant influence over such entities exists. Investments in unconsolidated entities consist of capital contributions and advances plus the Partnership's share of accumulated earnings as of the entities' latest fiscal year-ends, less capital withdrawals and distributions. Investments in excess of the underlying net assets of equity method investees, specifically identifiable to property, plant and equipment, are amortized over the useful life of the related assets. Excess investment representing equity method goodwill is not amortized but is evaluated for impairment, annually. Under certain provisions of ASC 350-20, related to goodwill, this goodwill is not subject to amortization and is accounted for as a component of the investment. Equity method investments are subject to impairment under the provisions of ASC 323-10, which relates to the equity method of accounting for investments in common stock. No portion of the net income from these entities is included in the Partnership's operating income.

In December 2013, Cardinal recorded a $129,384 impairment charge related to long-lived assets of its Monroe Gas Storage Company, LLC ("Monroe"). This amount represents the carrying value of the assets in excess of their fair value. The impairment resulted from the weaker than anticipated results of operations of Monroe. The Partnership's share of this charge was $54,053 and is included in "Equity in loss of unconsolidated entities" in the Consolidated Statement of Operations for the year ended December 31, 2013. The Partnership evaluated its remaining investment in Cardinal and determined that no additional impairment was necessary.

The Partnership owns 100% of the Class A and Class B equity interests in Redbird. Redbird, as of December 31, 2013 and 2012, owned a 42.21% and 41.28% interest in Cardinal, respectively.

The Partnership owns 100% of the preferred interests in Martin Energy Trading LLC ("MET"), a subsidiary of Martin Resource Management.

The Partnership sold its unconsolidated 50% interest in Caliber Gathering, LLC ("Caliber") during 2013. See Note 10.

The Partnership's subsidiary, legal name of Prism Gas Systems I, L.P. ("Prism Gas"), owned unconsolidated 50% interests in three investees, which were sold in 2012. See Note 5.

Each of these interests is accounted for under the equity method of accounting.

(f) Property, Plant, and Equipment

Owned property, plant, and equipment is stated at cost, less accumulated depreciation. Owned buildings and equipment are depreciated using straight-line method over the estimated lives of the respective assets.

Equipment under capital leases is stated at the present value of minimum lease payments less accumulated amortization. Equipment under capital leases is amortized on a straight line basis over the estimated useful life of the asset.

Routine maintenance and repairs are charged to operating expense while costs of betterments and renewals are capitalized. When an asset is retired or sold, its cost and related accumulated depreciation are removed from the accounts, and the difference between net book value of the asset and proceeds from disposition is recognized as gain or loss.

(g) Goodwill and Other Intangible Assets

Goodwill is subject to a fair-value based impairment test on an annual basis, or more often if events or circumstances indicate there may be impairment. The Partnership is required to identify its reporting units and determine the carrying value of each reporting unit by assigning the assets and liabilities, including the existing goodwill and intangible assets. The Partnership is required to determine the fair value of each reporting unit and compare it to the carrying amount of the reporting unit. To the extent the carrying amount of a reporting unit exceeds the fair value of the reporting unit, the Partnership would be required to perform the second step of the impairment test, as this is an indication that the reporting unit goodwill may be impaired.

All four of the Partnership's “reporting units”, terminalling and storage, natural gas services, sulfur services and marine transportation, contain goodwill.

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in thousands, except where otherwise indicated)

The Partnership has performed the annual impairment tests as of August 31, 2013, 2012, and 2011, and determined fair value in each reporting unit based on the weighted average of two valuation techniques: (i) the discounted cash flow method and (ii) the guideline public company method. At August 31, 2013, 2012, and 2011, the estimated fair value of each of the four reporting units was in excess of its carrying value, resulting in no impairment.

No triggering events occurred that would cause the Partnership to perform an impairment test at either December 31, 2013 or 2012.

Significant changes in these estimates and assumptions could materially affect the determination of fair value for each reporting unit which could give rise to future impairment. Changes to these estimates and assumptions can include, but may not be limited to, varying commodity prices, volume changes and operating costs due to market conditions and/or alternative providers of services.

(h) Debt Issuance Costs

Debt issuance costs relating to the Partnership's revolving credit facility and senior unsecured notes are deferred and amortized over the terms of the debt arrangements.

In connection with the issuance, amendment, expansion and restatement of debt arrangements, the Partnership incurred debt issuance costs of $9,114, $204 and $3,588 in the years ended December 31, 2013, 2012 and 2011, respectively.

Due to a reduction in the number of lenders under the Partnership's multi-bank credit agreement, $502, $0 and $494 of the existing debt issuance costs were determined not to have continuing benefit and were expensed during 2013, 2012 and 2011, respectively. Remaining unamortized deferred issuance costs are amortized over the term of the revised debt arrangement.

Amortization of debt issuance costs, which is included in interest expense, totaled $3,700, $3,290 and $3,755 for the years ended December 31, 2013, 2012 and 2011, respectively. Accumulated amortization amounted to $5,270 and $6,014 at December 31, 2013 and 2012, respectively.

(i) Impairment of Long-Lived Assets

In accordance with ASC 360-10, long-lived assets, such as property, plant and equipment, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated future cash flows, an impairment charge is recognized by the amount by which the carrying amount of the asset exceeds the fair value of the asset. Assets to be disposed of would be separately presented in the balance sheet and reported at the lower of the carrying amount or fair value less costs to sell and are no longer depreciated. The assets and liabilities of a disposed group classified as held for sale would be presented separately in the appropriate asset and liability sections of the balance sheet. The Partnership has not identified any triggering events in 2013, 2012 or 2011 that would require an assessment for impairment of long-lived assets.

(j) Asset Retirement Obligations

Under ASC 410-20, which relates to accounting requirements for costs associated with legal obligations to retire tangible, long-lived assets, the Partnership records an Asset Retirement Obligation (“ARO”) at fair value in the period in which it is incurred by increasing the carrying amount of the related long-lived asset. In each subsequent period, the liability is accreted over time towards the ultimate obligation amount and the capitalized costs are depreciated over the useful life of the related asset. The Partnership’s fixed assets include land, buildings, transportation equipment, storage equipment, marine vessels and operating equipment.

(k) Derivative Instruments and Hedging Activities

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in thousands, except where otherwise indicated)

In accordance with certain provisions of ASC 815-10 related to accounting for derivative instruments and hedging activities, all derivatives and hedging instruments are included on the balance sheet as an asset or liability measured at fair value and changes in fair value are recognized currently in earnings unless specific hedge accounting criteria are met. If a derivative qualifies for hedge accounting, changes in the fair value can be offset against the change in the fair value of the hedged item through earnings or recognized in other comprehensive income until such time as the hedged item is recognized in earnings.

Derivative instruments not designated as hedges are marked to market with all market value adjustments being recorded in the Consolidated Statements of Operations. As of December 31, 2013, the Partnership did not have any hedging instruments outstanding. Fair value changes associated with the Partnership's hedges have been recorded in accumulated other comprehensive income (“AOCI”) as a component of equity during 2012 and 2011.

(l) Comprehensive Income

Comprehensive income includes net income and other comprehensive income. Other comprehensive income for the Partnership includes unrealized gains and losses on derivative financial instruments. In accordance with ASC 815-10, the Partnership records deferred hedge gains and losses on its derivative financial instruments that qualify as cash flow hedges as other comprehensive income.

(m) Use of Estimates

Management has made a number of estimates and assumptions relating to the reporting of assets and liabilities and the disclosure of contingent assets and liabilities to prepare these consolidated financial statements in conformity with accounting principles generally accepted in the U.S. Actual results could differ from those estimates.

(n) Indirect Selling, General and Administrative Expenses

Indirect selling, general and administrative expenses are incurred by Martin Resource Management and allocated to the Partnership to cover costs of centralized corporate functions such as accounting, treasury, engineering, information technology, risk management and other corporate services. Such expenses are based on the percentage of time spent by Martin Resource Management’s personnel that provide such centralized services. Under an omnibus agreement with Martin Resource Management, the Partnership is required to reimburse Martin Resource Management for indirect general and administrative and corporate overhead expenses. For the years ended December 31, 2013, 2012 and 2011, the conflicts committee of the Partnership's general partner (“Conflicts Committee”) approved reimbursement amounts of $10,621, $7,593 and $4,771, respectively, reflecting the Partnership's allocable share of such expenses. The Conflicts Committee will review and approve future adjustments in the reimbursement amount for indirect expenses, if any, annually.

(o) Environmental Liabilities and Litigation

The Partnership’s policy is to accrue for losses associated with environmental remediation obligations when such losses are probable and reasonably estimable. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than completion of the remedial feasibility study. Such accruals are adjusted as further information develops or circumstances change. Costs of future expenditures for environmental remediation obligations are not discounted to their present value. Recoveries of environmental remediation costs from other parties are recorded as assets when their receipt is deemed probable.

(p) Accounts Receivable and Allowance for Doubtful Accounts.

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. The allowance for doubtful accounts is the Partnership's best estimate of the amount of probable credit losses in the Partnership's existing accounts receivable.

(q) Deferred Catalyst Costs

The cost of the periodic replacement of catalysts is deferred and amortized over the catalyst's estimated useful life, which ranges from 24 to 36 months.

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in thousands, except where otherwise indicated)

(r) Deferred Turnaround Costs

The Partnership capitalizes the cost of major turnarounds and amortizes these costs over the estimated period to the next turnaround, which ranges from 24 to 36 months.

(s) Income Taxes

With respect to the Partnership's taxable subsidiary (Woodlawn Pipeline Co., Inc.) and the Blending and Packaging Assets prior to the date of acquisition from Cross, income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

As discussed further in Note 19, the assets of the Partnership's taxable subsidiary Woodlawn Pipeline Co., Inc were disposed of on July 31, 2012. The entity was dissolved on December 31, 2012.

(3) Recent Accounting Pronouncements

In February 2013, the FASB amended the provisions of ASC 220 related to AOCI, which does not change the current requirements for reporting net income or other comprehensive income in financial statements. The standard requires entities to provide information about the amounts reclassified out of AOCI by component. The entity is required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of AOCI by the respective line items of net income but only if the amount reclassified is required under United States Generally Accepted Accounting Principles ("U.S. GAAP") to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under U.S. GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under U.S. GAAP that provide additional detail about those amounts. This amended guidance was adopted by the Partnership effective January 1, 2013. As this new guidance only requires enhanced disclosure, adoption did not impact the Partnership's financial position or results of operations.

(4) Acquisitions

Marine Transportation Equipment Purchase

On September 30, 2013, the Partnership acquired two previously leased inland tank barges from Martin Resource Management for $7,100. This acquisition is considered a transfer of net assets between entities under common control. The acquisition of these assets was recorded at the historical carrying value of the assets at the acquisition date. The Partnership recorded $6,799 to property, plant and equipment in the Marine Transportation segment and the excess of the purchase price over the carrying value of the assets of $301 was recorded as an adjustment to partners' capital. This transaction was funded with borrowings under the Partnership's revolving credit facility.

Sulfur Production Facility

On August 5, 2013, the Partnership acquired a plant nutrient sulfur production facility in Cactus, Texas for $4,118. The transaction was accounted for under the acquisition method of accounting in accordance with ASC 805 relating to business combinations. This transaction was funded by borrowings under the Partnership's revolving credit facility. Assets acquired and liabilities assumed were recorded in the Sulfur Services segment at fair value as follows:

Inventory	$162
Property, plant and equipment	4,000
Current liabilities	(44)
Total	$4,118

MARTIN MIDSTREAM PARTNERS L.P.
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The Partnership's results of operations from these assets included revenues of $267 and a net loss of $284 for the year ended December 31, 2013.

NL Grease, LLC

On June 13, 2013, the Partnership acquired certain assets of NL Grease, LLC (“NLG”) for $12,148. NLG is a Kansas City, Missouri based grease manufacturer that specializes in private-label packaging of commercial and industrial greases. The transaction was accounted for under the acquisition method of accounting in accordance with ASC 805 relating to business combinations. This transaction was funded by borrowings under the Partnership's revolving credit facility. The assets acquired by the Partnership were recorded in the Terminalling and Storage segment at fair value of $12,148 in the following purchase price allocation:

Inventory and other current assets	$1,513
Property, plant and equipment	6,136
Other assets	5,113
Other accrued liabilities	(168)
Other long-term obligations	(446)
Total	$12,148

The purchase price allocation resulted in the recognition of $5,113 in definite-lived intangible assets with no residual value, including $2,418 of technology, $2,218 attributable to a customer list, and $477 attributable to a non-compete agreement. The amounts assigned to technology, the customer list, and the non-compete agreement are amortized over the estimated useful life of ten years, three years, and five years, respectively. The weighted average life over which these acquired intangibles will be amortized is approximately six years.

The Partnership completed the purchase price allocation during the third quarter of 2013, which resulted in an adjustment to working capital from the preliminary purchase price allocation in the amount of $55.

The Partnership's results of operations included revenues of $7,875 and a net loss of $167 for the year ended December 31, 2013 related to the NLG acquisition.

NGL Marine Equipment Purchase

On February 28, 2013, the Partnership purchased from affiliates of Florida Marine Transporters, Inc. six liquefied petroleum gas pressure barges and two commercial push boats for approximately $50,801, of which the commercial push boats totaling $8,201 were allocated to property, plant and equipment in the Partnership's Marine Transportation segment and the six pressure barges totaling $42,600 were allocated to property, plant and equipment in the Partnership's Natural Gas Services segment. This transaction was funded with borrowings under the Partnership's revolving credit facility.

Talen's Marine & Fuel, LLC

On December 31, 2012, the Partnership acquired all of the outstanding membership interests in Talen's Marine & Fuel LLC (“Talen's”) from QEP Marine Fuel Investment, LLC and QEP Marine Fuel Holdings, Inc. (collectively referred to as “Quintana Energy Partners”) for $103,368, subject to certain post-closing adjustments, including the assumption of a note payable in the amount of $2,971. The transaction was accounted for under the acquisition method of accounting in accordance with ASC 805 relating to business combinations. Additionally, as required by ASC 805, the Partnership

expensed acquisition related costs, of which $58 were recorded in selling, general and administrative expenses for the year ended December 31, 2013. Through this acquisition, the Partnership acquired certain terminalling facilities and other terminalling related assets located along the Texas and Louisiana gulf coast. This transaction was funded by borrowings under the Partnership's revolving credit facility. Simultaneous with the acquisition, the Partnership sold certain working capital-related assets and a customer relationship intangible asset to Martin Energy Services LLC (“MES”), a wholly-owned subsidiary of Martin Resource Management for $56,000. Due to the Talen's acquisition, MES entered into various service agreements with Talen's pursuant to which the Partnership provides certain terminalling and marine services to MES. The excess carrying value of the assets over the purchase price paid by Martin Resource Management at the sales date was $4,268 and was recorded as an adjustment to

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partners' capital. The remaining net assets retained by the Partnership were recorded at fair value of $43,100 in the following purchase price allocation:

Purchase price paid to acquire Talen's	$103,368
Less proceeds received from Martin Resource Management for assets sold (described above)	(56,000)
Less excess of carrying value of assets sold to Martin Resource Management over the purchase price paid by Martin Resource Management	(4,268)
Total	$43,100

Cash	$5,096
Accounts and other receivables, net	1,932
Other current assets	685
Assets held for sale	3,578
Property, plant and equipment	23,656
Goodwill	15,465
Notes payable	(2,971)
Current liabilities	(3,872)
Other long-term obligations	(469)
Total	$43,100

Goodwill recognized from the acquisition primarily relates to the expected contributions of the entity to the overall corporate strategy in addition to synergies and acquired workforce, which are not separable from goodwill.

The Partnership's results of operations included revenues of $5,226 and net income of $1,038 for the year ended December 31, 2013 related to the Talen's acquisition.

Lubricant Blending and Packaging Assets

On October 2, 2012, the Partnership purchased the Blending and Packaging Assets from Cross. The consideration consisted of $121,767 in cash at closing, plus a final net working capital adjustment of $907 paid in October of 2012. This transaction was funded by borrowings under the Partnership's revolving credit facility. This acquisition is considered a transfer of net assets between entities under common control. The acquisition of the Blending and Packaging Assets was recorded at the historical carrying value of the assets at the acquisition date, which were as follows:

Accounts receivable, net	$20,599
Inventory	18,730
Other current assets	769
Property, plant and equipment, net	24,692
Current liabilities	(2,424)
Total	$62,366

The excess purchase price over the historical carrying value of the assets at the acquisition date was $60,308 and was recorded as an adjustment to partners' capital.

Redbird Class A Interests

On October 2, 2012, the Partnership acquired from Martin Resource Management all of the remaining Class A interests in Redbird for $150,000 in cash. The Partnership began making Class A investments in Redbird during the

fourth quarter of 2011. Prior to the transaction, the Partnership owned a 10.74% Class A interest and a 100% Class B interest in Redbird. This transaction was funded by borrowings under the Partnership's revolving credit facility. This acquisition is considered a transfer of net assets between entities under common control. The acquisition of these interests was recorded at the historical carrying value of the interests at the acquisition date. The Partnership recorded an investment in consolidated

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entities of $68,233 and the excess of the purchase price over the carrying value of the Class A interests of $81,767 was recorded as an adjustment to partners' capital.

Redbird Class B Interests

On May 31, 2011, the Partnership acquired all of the Class B equity interests in Redbird for approximately $59,319. This amount was recorded as an investment in an unconsolidated entity. Concurrent with the closing of this transaction, Cardinal acquired all of the outstanding equity interests in Monroe as well as an option on development rights to an adjacent depleted reservoir facility. This transaction was funded by borrowings under the Partnership's revolving credit facility.

Terminalling Facilities

On January 31, 2011, the Partnership acquired 13 shore-based marine terminalling facilities, one specialty terminalling facility and certain terminalling related assets from Martin Resource Management for $36,500. These assets are located across the Louisiana Gulf Coast. This transaction was funded by borrowings under the Partnership's revolving credit facility.

These terminalling assets were acquired by Martin Resource Management in its acquisition of L&L Holdings, LLC ("L&L") on January 31, 2011. During the second quarter of 2011, Martin Resource Management finalized the purchase price allocation for the acquisition of L&L, including the final determination of the fair value of the terminalling assets acquired by the Partnership. The Partnership recorded an adjustment in the amount of $19,685 to reduce property, plant and equipment and partners' capital for the difference between the purchase price and the fair value of the terminalling assets acquired based on Martin Resource Management's final purchase price allocation.

(5) Discontinued Operations and Divestitures

On July 31, 2012, the Partnership completed the sale of its East Texas and Northwest Louisiana natural gas gathering and processing assets owned by Prism Gas and other natural gas gathering and processing assets also owned by the Partnership to a subsidiary of CenterPoint Energy Inc. (NYSE: CNP) ("CenterPoint"). The Partnership received net cash proceeds from the sale of $273,269. The asset sale included the Partnership's 50% operating interest in Waskom Gas Processing Company ("Waskom"). A subsidiary of CenterPoint owned the other 50% percent interest.

Additionally, on September 18, 2012, the Partnership completed the sale of its interest in Matagorda Offshore Gathering System ("Matagorda") and Panther Interstate Pipeline Energy, LLC ("PIPE") to a private investor group for $1,530.

The Partnership classified the results of operations of the Prism Assets which were previously presented as a component of the Natural Gas Services segment, as discontinued operations in the Consolidated Statements of Operations for all periods presented.

The Prism Assets' operating results, which are included in income from discontinued operations, were as follows:

	Year Ended December 31,	
	2012	2011
Total revenues from third parties[1]	$66,876	$121,338
Total costs and expenses and other, net, excluding depreciation and amortization	(64,562)	(115,957)
Depreciation and amortization	(2,320)	(5,512)

Other operating income[2]	61,858	—
Equity in earnings of unconsolidated entities[3]	4,611	9,412
Income from discontinued operations before income taxes	66,463	9,281
Income tax (expense) benefit	(1,598)	111
Income from discontinued operations, net of income taxes	$64,865	$9,392

[1] Total revenues from third parties excludes intercompany revenues of $26,431, and $67,141 for the years ended December 31, 2012 and 2011, respectively.

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[2] The Partnership recognized a gain on the sale of the Prism Assets of $61,848 in income from discontinued operations for the year ended December 31, 2012.

[3] Represents equity in earnings of Waskom, Matagorda, and PIPE for the years ended December 31, 2012 and 2011.

(6) Inventories

Components of inventories at December 31, 2013 and 2012 were as follows:

	2013	2012
Natural gas liquids	$31,859	$33,610
Sulfur	8,912	14,892
Sulfur based products	17,584	17,824
Lubricants	33,847	27,366
Other	2,700	2,295
	$94,902	$95,987

(7) Property, Plant and Equipment

At December 31, 2013 and 2012, property, plant, and equipment consisted of the following:

	Depreciable Lives	2013	2012
Land	—	$21,971	$22,235
Improvements to land and buildings	10-25 years	131,941	104,788
Transportation equipment	3-7 years	1,802	1,757
Storage equipment	5-20 years	104,949	86,870
Marine vessels	4-25 years	309,147	246,536
Operating equipment	3-20 years	287,268	272,192
Furniture, fixtures and other equipment	3-20 years	3,742	3,510
Construction in progress		68,363	29,456
		$929,183	$767,344

Depreciation expense for the years ended December 31, 2013, 2012 and 2011 was $49,874, $40,724, and $37,869, respectively, which includes amortization of fixed assets under capital lease obligations of $233, $280 and $280, respectively. All capital lease obligations were retired in November 2013. Gross assets and accumulated amortization related to the assets under capital leases at December 31, 2012 were $7,764 and $955, respectively.

Additions to property, plant and equipment included in accounts payable at December 31, 2013 were $6,803.

(8) Goodwill and Other Intangibles

The following table represents the goodwill balance at December 31, 2012, changes during the year, and the resulting balances at December 31, 2013:

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	December 31, 2012	Talen's Acquisition[1]	December 31, 2013
Carrying amount of goodwill:			
Terminalling and storage	$10,352	$3,877	$14,229
Natural gas services	79	—	79
Sulfur services	5,349	—	5,349
Marine transportation	3,836	309	4,145
Total goodwill	$19,616	$4,186	$23,802

[1] These changes represent the amounts allocated to goodwill as part of the purchase price accounting adjustments made during the completion of the Talen's purchase price allocation in 2013. See Note 4 for discussion of the Talen's acquisition.

Other intangible assets subject to amortization consist of covenants not-to-compete, customer lists, and technology-based assets.

The unamortized balance of other intangible assets, included in the Consolidated Balance Sheets as other assets, net, amounted to $4,158 and $198 at December 31, 2013 and 2012, respectively.

Aggregate amortization expense for intangible assets included in continuing operations was $1,153, $140, and $140, for the years ended December 31, 2013, 2012 and 2011, respectively, and accumulated amortization amounted to $2,353 and $1,200 at December 31, 2013 and 2012, respectively.

Estimated amortization expenses for the years subsequent to December 31, 2013 are as follows: 2014 - $1,435; 2015 - $816; 2016 - $461; 2017 - $349; 2018 - $273; subsequent years - $824.

(9) Leases

The Partnership has numerous non-cancelable operating leases primarily for terminal facilities and transportation and other equipment. The leases generally provide that all expenses related to the equipment are to be paid by the lessee. Management expects to renew or enter into similar leasing arrangements for similar equipment upon the expiration of the current lease agreements. The Partnership also has cancelable operating lease land rentals and outside marine vessel charters.

The Partnership’s future minimum lease obligations as of December 31, 2013 consist of the following:

Fiscal year	Operating Leases
2014	$12,172
2015	11,266
2016	10,161
2017	5,965
2018	3,330
Thereafter	6,520
Total	$49,414

Rent expense for continuing operating leases for the years ended December 31, 2013, 2012 and 2011 was $15,629, $15,801 and $19,280, respectively. The amount recognized in interest expense for capital leases was $796, $945, and $972 for the years ended December 31, 2013, 2012 and 2011, respectively. As discussed in Note 15, the Partnership's capital lease obligations were retired in November of 2013.

(10) Investments in Unconsolidated Entities and Joint Ventures

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As discussed in detail in Note 5, the Partnership sold its 50% interests in Waskom, Matagorda, and PIPE in 2012. The equity in earnings associated with these investments during the periods owned is recorded in income from discontinued operations for the years ended December 31, 2012 and 2011.

On May 1, 2008, certain assets and liabilities were contributed to acquire a 50% ownership interest in Cardinal. In conjunction with this transaction, ECP contributed cash for a 50% ownership interest in Cardinal.

The initial carrying amount of the investment in Cardinal was less than the contributed underlying net assets. Of the basis difference, $1,250 relates to differences in the carrying value of fixed assets contributed as compared to amounts recorded by Cardinal, and is being amortized over 40 years, the approximate useful life of the underlying assets. Such amortization amounted to $31 for each of the three years ending December 31, 2013, 2012 and 2011. The remaining basis difference is a permanent difference that will be realized upon sale of the investment in Cardinal.

On May 24, 2011, Redbird was formed to hold membership interests in Cardinal. On May 27, 2011, initial contributions consisted of all of Martin Resource Management’s membership interests in Cardinal for 100% of the Class A interests in Redbird. Simultaneously, the Partnership acquired 100% of the Class B interests in Redbird for approximately $59,319. Concurrent with the closing of this transaction, Redbird contributed the cash to Cardinal which used the cash, along with a contribution from ECP, to acquire all of the outstanding equity interests in Monroe as well as an option on development rights to an adjacent depleted reservoir facility. As discussed in Notes 2 and 4, on October 2, 2012, the Partnership, acquired the remaining Class A interests in Redbird. As this acquisition is considered a transfer of net assets between entities under common control, the acquisition is recorded at the historical carrying value of these assets at that date. The Partnership is required to retrospectively update its historical financial statements to include the activities of the Class A interests in Redbird as of the date of common control. The Partnership's accompanying historical financial statements for the years ended December 31, 2012 and 2011 have been retrospectively updated to reflect the effects on financial position, cash flows and results of operations attributable to the Redbird Class A interests (including predecessor activities related to the amounts contributed to form Cardinal and Cardinal activities prior to the formation of Redbird) as if the Partnership owned these assets for these periods.

In December 2013, Cardinal recorded a $129,384 impairment charge related to long-lived assets of Monroe. This amount represents the carrying value of the assets in excess of their fair value. The impairment resulted from the weaker than anticipated results of operations of Monroe. The Partnership's share of this charge is $54,053 and is included in “Equity in loss of unconsolidated entities” in the Consolidated Statement of Operations for the year ended December 31, 2013. The Partnership evaluated its remaining investment in Cardinal and determined that no additional impairment was necessary.

As of December 31, 2013, Redbird owned an unconsolidated 42.21% interest in Cardinal.

During March 2013, the Partnership acquired 100% of the preferred interests in MET for $15,000.

During the second quarter of 2012, the Partnership acquired an unconsolidated 50% interest in Caliber and Pecos Valley Producer Services, LLC (“Pecos Valley”). The Partnership sold its interest in Caliber during the fourth quarter of 2013 for $750, resulting in a gain of $750 recorded in other, net in the Partnership's Consolidated Statements of Operations for the year ended December 31, 2013. The Partnership sold its interest in Pecos Valley during the third quarter of 2012 for $531, resulting in a gain of $486 recorded in other, net in the Partnership's Consolidated Statement of Operations for the year ended December 31, 2012.

These investments are accounted for by the equity method.

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The following tables summarize the components of the investment in unconsolidated entities on the Partnership's Consolidated Balance Sheets and the components of equity in earnings of unconsolidated entities included in the Partnership's Consolidated Statements of Operations:

	December 31, 2013	December 31, 2012
Cardinal	$113,662	$153,749
MET	15,000	—
Caliber	—	560
Total investment in unconsolidated entities	$128,662	$154,309

	Years Ended December 31,		
	2013	2012	2011
Equity in earnings of Waskom[1]	$—	$4,172	$9,143
Equity in loss of PIPE[1]	—	(60)	(45)
Equity in earnings of Matagorda[1]	—	499	314
Equity in earnings of discontinued operations	—	4,611	9,412
Equity in loss of Cardinal	(54,226)	(943)	(4,752)
Equity in earnings of MET	1,738	—	—
Equity in loss of Caliber	(560)	(190)	—
Equity in earnings of Pecos Valley	—	20	—
Equity in earnings (loss) of unconsolidated entities	(53,048)	(1,113)	(4,752)
Total equity in earnings of unconsolidated entities	$(53,048)	$3,498	$4,660

[1] For all periods presented, the financial information for Waskom, Matagorda, and PIPE is included on the Consolidated Statements of Operations and Cash Flows as discontinued operations.

Selected financial information for significant unconsolidated equity method investees is as follows:

	As of December 31,		Years ended December 31,	
	Total Assets	Partners' Capital	Revenues	Net Income
2012				
Waskom	$—	$—	$66,662	$8,986
2011				
Waskom	$146,655	$126,863	$129,119	$19,385

	As of December 31,			Years ended December 31,	
	Total Assets	Long-Term Debt	Members' Equity	Revenues	Net Loss
2013					
Cardinal	$661,816	$295,261	$346,584	$52,762	$(128,283)
2012					
Cardinal	$694,767	$210,079	$457,297	$31,999	$(5,951)
2011					
Cardinal	$561,375	$122,064	$422,935	$19,471	$(11,534)

As of December 31, 2013 and 2012, the Partnership's interest in cash of the unconsolidated equity method investees was $3,703 and $1,265, respectively.

(11) Fair Value Measurements

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The Partnership uses a valuation framework based upon inputs that market participants use in pricing certain assets and liabilities. These inputs are classified into two categories: observable inputs and unobservable inputs. Observable inputs represent market data obtained from independent sources. Unobservable inputs represent the Partnership's own market assumptions. Unobservable inputs are used only if observable inputs are unavailable or not reasonably available without undue cost and effort. The two types of inputs are further prioritized into the following hierarchy:

Level 1: Quoted market prices in active markets for identical assets or liabilities.
Level 2: Observable market based inputs or unobservable inputs that are corroborated by market data.
Level 3: Unobservable inputs that reflect the entity's own assumptions and are not corroborated by market data.

The following items are measured at fair value on a recurring and non-recurring basis at December 31, 2013 and 2012:

		Fair Value Measurements at Reporting Date Using		
Description	December 31, 2013	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Liabilities				
2018 Senior unsecured notes	$185,816	$—	$185,816	$—
2021 Senior unsecured notes	258,004	—	258,004	—
Total liabilities	$443,820	$—	$443,820	$—

		Fair Value Measurements at Reporting Date Using		
Description	December 31, 2012	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Liabilities				
2018 Senior unsecured notes	$187,066	$—	$187,066	$—
Total liabilities	$187,066	$—	$187,066	$—

The Partnership is required to disclose estimated fair values for its financial instruments. Fair value estimates are set forth below for these financial instruments. The following methods and assumptions were used to estimate the fair value of each class of financial instrument:

- Accounts and other receivables, trade and other accounts payable, accrued interest payable, other accrued liabilities, income taxes payable and due from/to affiliates: The carrying amounts approximate fair value due to the short maturity and highly liquid nature of these instruments, and as such these have been excluded from the table above.

- Long-term debt including current portion: The carrying amount of the revolving credit facility approximates fair value due to the debt having a variable interest rate and is in Level 2. The estimated fair value of the senior unsecured notes is based on market prices of similar debt. The carrying amount of the note payable to bank as of December 31, 2012 is not deemed to be significantly different than the fair value. This note was retired during 2013.

(12) Derivative Instruments and Hedging Activities

The Partnership's results of operations are materially impacted by changes in crude oil, natural gas and NGL prices and interest rates. In an effort to manage its exposure to these risks, the Partnership periodically enters into various derivative instruments, including commodity and interest rate hedges.

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(a) Commodity Derivative Instruments

The Partnership has from time to time used derivatives to manage the risk of commodity price fluctuation. The Partnership has established a hedging policy and monitors and manages the commodity market risk associated with potential commodity risk exposure. These hedging arrangements have been in the form of swaps for crude oil, natural gas and natural gasoline. In addition, the Partnership has focused on utilizing counterparties for these transactions whose financial condition is appropriate for the credit risk involved in each specific transaction.

Due to the sale of the Prism Assets during 2012, the Partnership terminated and settled all of its commodity derivative instruments during the second quarter of 2012. For the years ended December 31, 2012 and 2011, changes in the fair value of the Partnership's derivative contracts were recorded in both earnings (income from discontinued operations) and in AOCI as a component of partners' capital. As of December 31, 2013, the Partnership did not have any commodity derivative instruments outstanding.

(b) Impact of Commodity Cash Flow Hedges

Crude Oil. For the years ended December 31, 2012 and 2011, net gains and losses on swap hedge contracts increased crude revenue (included in income from discontinued operations) by $496 and $775, respectively.

Natural Gas. For the years ended December 31, 2012 and 2011, net gains and losses on swap hedge contracts increased gas revenue (included in income from discontinued operations) by $813 and $332, respectively.

Natural Gas Liquids. For the years ended December 31, 2012 and 2011, net gains and losses on swap hedge contracts increased liquids revenue (included in income from discontinued operations) by $1,066 and $254, respectively.

For information regarding fair value amounts and gains and losses on commodity derivative instruments and related hedged items, see "Tabular Presentation of Fair Value Amounts, and Gains and Losses on Derivative Instruments and Related Hedged Items" within this Note.

(c) Impact of Interest Rate Derivative Instruments

The Partnership is exposed to market risks associated with interest rates. From time to time, the Partnership enters into interest rate swaps to manage interest rate risk associated with the Partnership's variable rate debt and term loan credit facilities. As of December 31, 2013, the Partnership did not have any interest rate derivative instruments outstanding.

In August 2011, the Partnership terminated all of its existing interest swap agreements with an aggregate notional amount of $100,000, which it had entered to hedge its exposure to changes in the fair value of the 2018 senior unsecured notes. These interest rate swap contracts were not designated as fair value hedges and therefore, did not receive hedge accounting but were marked to market through earnings. A termination benefit of $2,800 was received on the early extinguishment of the interest rate swap agreements in August 2011.

The Partnership recognized increases in interest expense of $0 and $5,779 for the years ended December 31, 2012 and 2011, respectively, related to the difference between the fixed rate and the floating rate of interest on the interest rate swap and net cash settlement of interest rate swaps and hedges.

For information regarding fair value amounts and gains and losses on interest rate derivative instruments and related hedged items, see "Tabular Presentation of Gains and Losses on Derivative Instruments and Related Hedged

Items" below.

Tabular Presentation of Gains and Losses on Derivative Instruments and Related Hedged Items

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Effect of Derivative Instruments on the Consolidated Statements of Operations For the Years Ended December 31, 2012 and 2011

	Effective Portion					Ineffective Portion and Amount Excluded from Effectiveness Testing		
	2012	2011	Location of Gain or (Loss) Reclassified from Accumulated OCI into Income	2012	2011	Location of Gain or (Loss) Recognized in Income on Derivatives	2012	2011
Derivatives designated as hedging instruments:								
Interest Rate contracts	$—	$—	Interest expense	$—	$(18)	Interest expense	$—	$—
Commodity contracts	126	1,011	Income from discontinued operations	748	1,785	Income from discontinued operations	4	37
Total derivatives designated as hedging instruments	$126	$1,011		$748	$1,767		$4	$37

	Location of Gain or (Loss) Recognized in Income on Derivatives	Amount of Gain or (Loss) Recognized in Income on Derivatives	
		2012	2011
Derivatives not designated as hedging instruments:			
Interest rate contracts	Interest expense	$—	$5,797
Commodity contracts	Income from discontinued operations	1,623	(461)
Total derivatives not designated as hedging instruments		$1,623	$5,336

(13) Related Party Transactions

As of December 31, 2013, Martin Resource Management owned 5,093,267 of the Partnership's common units representing approximately 19.1% of the Partnership's outstanding limited partnership units. Martin Resource Management controls the Partnership's general partner by virtue of its 51% voting interest in Holdings, the sole member of the Partnership's general partner. The Partnership's general partner, MMGP, owns a 2% general partner interest in the Partnership and the Partnership's incentive distribution rights ("IDRs"). The Partnership's general partner's ability, as general partner, to manage and operate the Partnership, and Martin Resource Management's ownership as of December 31, 2013, of approximately 19.1% of the Partnership's outstanding limited partnership units, effectively gives Martin Resource Management the ability to veto some of the Partnership's actions and to control the Partnership's management.

The following is a description of the Partnership's material related party agreements:

Omnibus Agreement

Omnibus Agreement. The Partnership and its general partner are parties to an omnibus agreement dated November 1, 2002, with Martin Resource Management (the "Omnibus Agreement") that governs, among other things, potential competition and indemnification obligations among the parties to the agreement, related party transactions, the provision of general administration and support services by Martin Resource Management and the Partnership's use of certain of Martin Resource Management's trade names and trademarks. The Omnibus Agreement was amended on November 25, 2009, to include processing crude oil into finished products including naphthenic lubricants, distillates, asphalt and other intermediate cuts. The Omnibus Agreement was amended further on October 1, 2012, to permit the Partnership to provide certain lubricant packaging products and services to Martin Resource Management.

Non-Competition Provisions. Martin Resource Management has agreed for so long as it controls the general partner of the Partnership, not to engage in the business of:

- providing terminalling and storage services for petroleum products and by-products including the refining, blending and packaging of finished lubricants;

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•providing marine transportation of petroleum products and by-products;

•distributing NGLs; and

•manufacturing and selling sulfur-based fertilizer products and other sulfur-related products.

This restriction does not apply to:

•the ownership and/or operation on the Partnership’s behalf of any asset or group of assets owned by it or its affiliates;

•any business operated by Martin Resource Management, including the following:

providing land transportation of various liquids;

distributing fuel oil, sulfuric acid, marine fuel and other liquids;

providing marine bunkering and other shore-based marine services in Alabama, Florida, Louisiana, Mississippi and Texas;

operating a crude oil gathering business in Stephens, Arkansas;

providing crude oil gathering, refining, and marketing services of base oils, asphalt, and distillate products in Smackover, Arkansas;

operating an underground NGL storage facility in Arcadia, Louisiana;

operating an environmental consulting company;

operating an engineering services company;

supplying employees and services for the operation of the Partnership's business;

operating a natural gas optimization business;

operating, for its account and the Partnership's account, the docks, roads, loading and unloading facilities and other common use facilities or access routes at the Partnership's Stanolind terminal; and

operating, solely for the Partnership's account, the asphalt facilities in Omaha, Nebraska, Port Neches, Texas and South Houston, Texas.

•any business that Martin Resource Management acquires or constructs that has a fair market value of less than $5,000;

•any business that Martin Resource Management acquires or constructs that has a fair market value of $5,000 or more if the Partnership has been offered the opportunity to purchase the business for fair market value and the Partnership declines to do so with the concurrence of the Conflicts Committee; and

- any business that Martin Resource Management acquires or constructs where a portion of such business includes a restricted business and the fair market value of the restricted business is $5,000 or more and represents less than 20% of the aggregate value of the entire business to be acquired or constructed; provided that, following completion of the acquisition or construction, the Partnership will be provided the opportunity to purchase the restricted business.

Services. Under the Omnibus Agreement, Martin Resource Management provides the Partnership with corporate staff, support services, and administrative services necessary to operate the Partnership's business. The Omnibus Agreement requires the Partnership to reimburse Martin Resource Management for all direct expenses it incurs or payments it makes on the Partnership's behalf or in connection with the operation of the Partnership's business. There is no monetary limitation on the amount the Partnership is required to reimburse Martin Resource Management for direct expenses. In addition to the direct

expenses, under the Omnibus Agreement, the Partnership is required to reimburse Martin Resource Management for indirect general and administrative and corporate overhead expenses.

Effective January 1, 2014, through December 31, 2014, the Conflicts Committee approved an annual reimbursement amount for indirect expenses of $12,535. The Partnership reimbursed Martin Resource Management for $10,621, $7,593, and $4,772 of indirect expenses for the years ended December 31, 2013, 2012, and 2011, respectively. The Conflicts Committee will review and approve future adjustments in the reimbursement amount for indirect expenses, if any, annually.

These indirect expenses are intended to cover the centralized corporate functions Martin Resource Management provides for the Partnership, such as accounting, treasury, clerical, engineering, legal, billing, information technology, administration of insurance, general office expenses and employee benefit plans and other general corporate overhead functions the Partnership shares with Martin Resource Management retained businesses. The provisions of the Omnibus Agreement regarding Martin Resource Management's services will terminate if Martin Resource Management ceases to control the general partner of the Partnership.

Related Party Transactions. The Omnibus Agreement prohibits the Partnership from entering into any material agreement with Martin Resource Management without the prior approval of the Conflicts Committee. For purposes of the Omnibus Agreement, the term material agreements means any agreement between the Partnership and Martin Resource Management that requires aggregate annual payments in excess of then-applicable agreed upon reimbursable amount of indirect general and administrative expenses. Please read "Services" above.

License Provisions. Under the Omnibus Agreement, Martin Resource Management has granted the Partnership a nontransferable, nonexclusive, royalty-free right and license to use certain of its trade names and marks, as well as the trade names and marks used by some of its affiliates.

Amendment and Termination. The Omnibus Agreement may be amended by written agreement of the parties; provided, however, that it may not be amended without the approval of the Conflicts Committee if such amendment would adversely affect the unitholders. The Omnibus Agreement was first amended on November 25, 2009, to permit the Partnership to provide refining services to Martin Resource Management. The Omnibus Agreement was amended further on October 1, 2012, to permit the Partnership to provide certain lubricant packaging products and services to Martin Resource Management. Such amendments were approved by the Conflicts Committee. The Omnibus Agreement, other than the indemnification provisions and the provisions limiting the amount for which the Partnership will reimburse Martin Resource Management for general and administrative services performed on its behalf, will terminate if the Partnership is no longer an affiliate of Martin Resource Management.

Motor Carrier Agreement

Motor Carrier Agreement. The Partnership is a party to a motor carrier agreement effective January 1, 2006 as amended, with Martin Transport, Inc., a wholly owned subsidiary of Martin Resource Management through which Martin Transport, Inc. operates its land transportation operations. Under the agreement, Martin Transport, Inc. agreed to transport the Partnership's NGLs as well as other liquid products.

Term and Pricing. The agreement has an initial term that expired in December 2007 but automatically renews for consecutive one year periods unless either party terminates the agreement by giving written notice to the other party at least 30 days prior to the expiration of the then-applicable term. The Partnership has the right to terminate this agreement at any time by providing 90 days prior notice. Under this agreement, Martin Transport, Inc. transports the

Partnership's NGL shipments as well as other liquid products. These rates are subject to any adjustments which are mutually agreed or in accordance with a price index. Additionally, during the term of the agreement, shipping charges are also subject to fuel surcharges determined on a weekly basis in accordance with the U.S. Department of Energy's national diesel price list.

Indemnification. Martin Transport has indemnified us against all claims arising out of the negligence or willful misconduct of Martin Transport and its officers, employees, agents, representatives and subcontractors. We indemnified Martin Transport against all claims arising out of the negligence or willful misconduct of us and our officers, employees, agents, representatives and subcontractors. In the event a claim is the result of the joint negligence or misconduct of Martin Transport and us, our indemnification obligations will be shared in proportion to each party's allocable share of such joint negligence or misconduct.

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Marine Agreements

Marine Transportation Agreement. The Partnership is a party to a marine transportation agreement effective January 1, 2006, which was amended January 1, 2007, under which the Partnership provides marine transportation services to Martin Resource Management on a spot-contract basis at applicable market rates. Effective each January 1, this agreement automatically renews for consecutive one year periods unless either party terminates the agreement by giving written notice to the other party at least 60 days prior to the expiration of the then applicable term. The fees the Partnership charges Martin Resource Management are based on applicable market rates.

Marine Fuel. The Partnership is a party to an agreement with Martin Resource Management dated November 1, 2002 under which Martin Resource Management provides the Partnership with marine fuel from its locations in the Gulf of Mexico at a fixed rate in excess of the Platt's U.S. Gulf Coast Index for #2 Fuel Oil. Under this agreement, the Partnership agreed to purchase all of its marine fuel requirements that occur in the areas serviced by Martin Resource Management.

Terminal Services Agreements

Diesel Fuel Terminal Services Agreement. The Partnership is a party to an agreement under which the Partnership provides terminal services to Martin Resource Management. This agreement was amended and restated as of October 27, 2004, and was set to expire in December 2006, but automatically renewed and will continue to automatically renew on a month-to-month basis until either party terminates the agreement by giving 60 days' written notice. The per gallon throughput fee the Partnership charges under this agreement may be adjusted annually based on a price index.

Miscellaneous Terminal Services Agreements. The Partnership is currently party to several terminal services agreements and from time to time the Partnership may enter into other terminal service agreements for the purpose of providing terminal services to related parties. Individually, each of these agreements is immaterial but when considered in the aggregate they could be deemed material. These agreements are throughput based with a minimum volume commitment. Generally, the fees due under these agreements are adjusted annually based on a price index.

Talen's Agreements. In connection with the Talen's acquisition, new agreements were executed, each with effective dates of December 31, 2012. Under the terms of these contracts, Talen's provides terminal services to Martin Resource Management. The terminal services agreements both have five-year terms and provide a per gallon throughput rate, which may be adjusted annually based on a price index.

Other Agreements

Cross Tolling Agreement. The Partnership is a party to an agreement with Cross, originally dated November 25, 2009, under which the Partnership processes crude oil into finished products, including naphthenic lubricants, distillates, asphalt and other intermediate cuts for Cross. The tolling agreement, which has subsequently been amended, has a 22 year term which expires November 25, 2031. Under this tolling agreement, Cross agreed to process a minimum of 6,500 barrels per day of crude oil at the facility at a fixed price per barrel. Any additional barrels are processed at a modified price per barrel. In addition, Cross agreed to pay a monthly reservation fee and a periodic fuel surcharge fee based on certain parameters specified in the tolling agreement. All of these fees (other than the fuel surcharge) are subject to escalation annually based upon the greater of 3% or the increase in the Consumer Price Index for a specified annual period. In addition, every three years, the parties can negotiate an

upward or downward adjustment in the fees subject to their mutual agreement.

Sulfuric Acid Sales Agency Agreement. The Partnership is party to a second amended and restated sulfuric acid sales agency agreement dated August 5, 2013, under which Martin Resource Management purchases and markets the sulfuric acid produced by the Partnership's sulfuric acid production plant at Plainview, Texas, that is not consumed by the Partnership's internal operations. This agreement, as amended, will remain in place until the Partnership terminates it by providing 180 days' written notice. Under this agreement, the Partnership sells all of its excess sulfuric acid to Martin Resource Management. Martin Resource Management then markets such acid to third-parties and the Partnership shares in the profit of Martin Resource Management's sales of the excess acid to such third parties.

Other Miscellaneous Agreements. From time to time the Partnership enters into other miscellaneous agreements with Martin Resource Management for the provision of other services or the purchase of other goods.

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The tables below summarize the related party transactions that are included in the related financial statement captions on the face of the Partnership's Consolidated Statements of Operations. The revenues, costs and expenses reflected in these tables are tabulations of the related party transactions that are recorded in the corresponding caption of the Consolidated Statements of Operations and do not reflect a statement of profits and losses for related party transactions.

The impact of related party revenues from sales of products and services is reflected in the Consolidated Statements of Operations as follows:

Revenues:	2013	2012	2011
Terminalling and storage	$71,517	$64,669	$54,211
Marine transportation	24,654	17,494	23,478
Product sales:			
Natural gas services	10	113	716
Sulfur services	3,890	6,022	8,151
Terminalling and storage	798	1,066	214
	4,698	7,201	9,081
	$100,869	$89,364	$86,770

The impact of related party cost of products sold is reflected in the Consolidated Statements of Operations as follows:

Cost of products sold:			
Natural gas services	$32,639	$27,512	$16,749
Sulfur services	18,161	16,968	18,314
Terminalling and storage	48,868	48,375	45,089
	$99,668	$92,855	$80,152

The impact of related party operating expenses is reflected in the Consolidated Statements of Operations as follows:

Operating expenses:			
Marine transportation	$38,373	$28,495	$29,870
Natural gas services	1,971	1,855	1,590
Sulfur services	8,223	6,646	6,573
Terminalling and storage	21,766	21,838	20,018
	$70,333	$58,834	$58,051

The impact of related party selling, general and administrative expenses is reflected in the Consolidated Statements of Operations as follows:

Selling, general and administrative:			
Marine transportation	$50	$60	$65
Natural gas services	2,671	2,498	1,069
Sulfur services	3,081	2,964	2,704
Terminalling and storage	1,266	563	—
Indirect overhead allocation, net of reimbursement	10,665	7,593	4,772
	$17,733	$13,678	$8,610

(14) Other Accrued Liabilities

At December 31, 2013 and 2012, components of other accrued liabilities consisted of the following:

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	2013	2012
Accrued interest	$11,038	$4,492
Property and other taxes payable	6,785	2,770
Accrued payroll	2,186	1,991
Other	233	236
	$20,242	$9,489

(15) Long-Term Debt and Capital Leases

At December 31, 2013 and 2012, long-term debt consisted of the following:

	2013	2012
$600,000[3] Revolving loan facility at variable interest rate (3.21%[1] weighted average at December 31, 2013), due March 2018 secured by substantially all of the Partnership's assets, including, without limitation, inventory, accounts receivable, vessels, equipment, fixed assets and the interests in the Partnership's operating subsidiaries and equity method investees	$235,000	$296,000
$200,000[2,5] Senior notes, 8.875% interest, net of unamortized discount of $1,305 and $1,612, respectively, issued March 2010 and due April 2018, unsecured	173,695	173,388
$250,000 Senior notes, 7.250% interest, issued February 2013 and due February 2021, unsecured[4,5]	250,000	—
$3,315 Note payable to bank, interest rate at 4.75%, maturity date of October 2029, unsecured[7]	—	2,971
Capital lease obligations[6]	—	5,839
Total long-term debt and capital lease obligations	658,695	478,198
Less current portion	—	3,206
Long-term debt and capital lease obligations, net of current portion	$658,695	$474,992

[1] Interest rate fluctuates based on the LIBOR rate plus an applicable margin set on the date of each advance. The margin above LIBOR is set every three months. Indebtedness under the credit facility bears interest at LIBOR plus an applicable margin or the base prime rate plus an applicable margin. The applicable margin for revolving loans that are LIBOR loans ranges from 2.00% to 3.00% and the applicable margin for revolving loans that are base prime rate loans ranges from 1.00% to 2.00%. The applicable margin for LIBOR borrowings at December 31, 2013 is 3.00%. The credit facility contains various covenants which limit the Partnership's ability to make certain investments and acquisitions; enter into certain agreements; incur indebtedness; sell assets; and make certain amendments to the Omnibus Agreement. The Partnership is permitted to make quarterly distributions so long as no event of default exists.

[2] Pursuant to the indenture under which the senior notes were issued, the Partnership has the option to redeem up to 35% of the aggregate principal amount at a redemption price of 108.875% of the principal amount, plus accrued and unpaid interest with the proceeds of certain equity offerings. On April 24, 2012, the Partnership notified the trustee of its intention to exercise a partial redemption of the Partnership's senior notes pursuant to the indenture. On May 24, 2012, the Partnership redeemed $25,000 of the senior notes from various holders using proceeds of the Partnership's January 2012 follow-on equity offering, which in the interim were used to pay down amounts outstanding under the Partnership's revolving credit facility. In conjunction with the redemption, the Partnership incurred a debt prepayment premium in the amount of $2,219, which is included in the Consolidated Statement of Operations for the year ended December 31, 2012.

[3] Effective March 28, 2013, the Partnership increased the maximum amount of borrowings and letters of credit available under the Credit Facility from $400,000 to $600,000 and extended the maturity date of the facility from April 2016 to March 2018.

[4] On February 11, 2013, the Partnership completed a private placement of $250,000 in aggregate principal amount of 7.250% senior unsecured notes due 2021 to qualified institutional buyers under Rule 144A. The Partnership filed with the SEC a registration statement to exchange the 2021 Notes for substantially identical notes that are registered under the Securities Act, and completed the exchange offer on July 31, 2013.

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[5] The 2018 and 2021 indentures restrict the Partnership's ability to sell assets; pay distributions or repurchase units or redeem or repurchase subordinated debt; make investments; incur or guarantee additional indebtedness or issue preferred units; and consolidate, merge or transfer all or substantially all of its assets. Many of these covenants will terminate if the notes achieve an investment grade rating from each of Moody's Investors Service, Inc. and Standard & Poor's Ratings Services and no default (as defined in the indentures) has occurred.
[6] In November of 2013, the Partnership retired the capital lease obligations with borrowings under the Partnership's revolving credit facility. In conjunction with the retirement, the Partnership incurred a debt prepayment premium in the amount of $272, which is included in the Consolidated Statement of Operations for the year ended December 31, 2013.

[7] In October of 2013, the Partnership retired the note payable to bank with borrowings under the Partnership's revolving credit facility.

The Partnership paid cash interest in the amount of $33,038, $29,239, and $22,818 for the years ended December 31, 2013, 2012 and 2011, respectively. Capitalized interest was $1,096, $1,136, and $624 for the years ended December 31, 2013, 2012 and 2011, respectively.

(16) Partners' Capital

As of December 31, 2013, partners' capital consisted of 26,625,026 common limited partner units, representing a 98% partnership interest and a 2% general partner interest. Martin Resource Management, through subsidiaries, owned 5,093,267 of the Partnership's common limited partnership units representing approximately 19.1% of the Partnership's outstanding common limited partnership units. MMGP, the Partnership's general partner, owns the 2% general partnership interest.

The partnership agreement of the Partnership (the "Partnership Agreement") contains specific provisions for the allocation of net income and losses to each of the partners for purposes of maintaining their respective partner capital accounts.

Issuance of Common Units

On November 26, 2012, the Partnership completed a public offering of 3,450,000 common units at a price of $31.16 per common unit, before the payment of underwriters' discounts, commissions and offering expenses (per unit value is in dollars, not thousands). Total proceeds from the sale of the 3,450,000 common units, net of underwriters' discounts, commissions and offering expenses were $102,809. The Partnership's general partner contributed $2,194 in cash to the Partnership in conjunction with the issuance in order to maintain its 2% general partner interest in the Partnership. All of the net proceeds were used to reduce outstanding indebtedness of the Partnership.

On January 25, 2012, the Partnership completed a public offering of 2,645,000 common units at a price of $36.15 per common unit, before the payment of underwriters' discounts, commissions and offering expenses (per unit value is in dollars, not thousands). Total proceeds from the sale of the 2,645,000 common units, net of underwriters' discounts, commissions and offering expenses were $91,361. The Partnership's general partner contributed $1,951 in cash to the Partnership in conjunction with the issuance in order to maintain its 2% general partner interest in the Partnership. All of the net proceeds were used to reduce outstanding indebtedness of the Partnership.

On February 9, 2011, the Partnership completed a public offering of 1,874,500 common units at a price of $39.35 per common unit, before the payment of underwriters' discounts, commissions and offering expenses (per unit value is in

dollars, not thousands). Total proceeds from the sale of the 1,874,500 common units, net of underwriters' discounts, commissions and offering expenses were $70,330. The Partnership's general partner contributed $1,505 in cash to the Partnership in conjunction with the issuance in order to maintain its 2% general partner interest in the Partnership. All of the net proceeds were used to reduce outstanding indebtedness of the Partnership.

Incentive Distribution Rights

The Partnership's general partner, MMGP, holds a 2% general partner interest and certain incentive distribution rights ("IDRs") in the Partnership. IDRs are a separate class of non-voting limited partner interest that may be transferred or sold by the general partner under the terms of the Partnership Agreement, and represent the right to receive an increasing percentage of cash distributions after the minimum quarterly distribution and any cumulative arrearages on common units once certain target

distribution levels have been achieved. The Partnership is required to distribute all of its available cash from operating surplus, as defined in the Partnership Agreement. On October 2, 2012, the Partnership Agreement was amended to provide that the general partner shall forego the next $18,000 in incentive distributions that it would otherwise be entitled to receive. No incentive distributions were allocated to the general partner from July 1, 2012 (which would have been payable to the general partner on November 14, 2012 for the third quarter of 2012 distribution) through December 31, 2013. As of December 31, 2013, the amount of incentive distributions the general partner has foregone is $9,647, resulting in an amount remaining of $8,353.

The target distribution levels entitle the general partner to receive 2% of quarterly cash distributions up to $0.55 per unit, 15% of quarterly cash distributions in excess of $0.55 per unit until all unitholders have received $0.625 per unit, 25% of quarterly cash distributions in excess of $0.625 per unit until all unitholders have received $0.75 per unit and 50% of quarterly cash distributions in excess of $0.75 per unit.

For the years ended December 31, 2013, 2012 and 2011, the general partner received $0, $2,857, and $4,901 in incentive distributions.

Distributions of Available Cash

The Partnership distributes all of its available cash (as defined in the Partnership Agreement) within 45 days after the end of each quarter to unitholders of record and to the general partner. Available cash is generally defined as all cash and cash equivalents of the Partnership on hand at the end of each quarter less the amount of cash reserves its general partner determines in its reasonable discretion is necessary or appropriate to: (i) provide for the proper conduct of the Partnership’s business; (ii) comply with applicable law, any debt instruments or other agreements; or (iii) provide funds for distributions to unitholders and the general partner for any one or more of the next four quarters, plus all cash on the date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter.

Net Income per Unit

The Partnership follows the provisions of the FASB ASC 260-10 related to earnings per share, which addresses the application of the two-class method in determining income per unit for master limited partnerships having multiple classes of securities that may participate in partnership distributions accounted for as equity distributions. Undistributed earnings are allocated to the general partner and limited partners utilizing the contractual terms of the Partnership Agreement. Distributions to the general partner pursuant to the IDRs are limited to available cash that will be distributed as defined in the Partnership Agreement. Accordingly, the Partnership does not allocate undistributed earnings to the general partner for the IDRs because the general partner's share of available cash is the maximum amount that the general partner would be contractually entitled to receive if all earnings for the period were distributed. When current period distributions are in excess of earnings, the excess distributions for the period are to be allocated to the general partner and limited partners based on their respective sharing of losses specified in the Partnership Agreement. Additionally, as required under FASB ASC 260-10-45-61A, unvested share-based payments that entitle employees to receive non-forfeitable distributions are considered participating securities, as defined in FASB ASC 260-10-20, for earnings per unit calculations.

For purposes of computing diluted net income per unit, the Partnership uses the more dilutive of the two-class and if-converted methods. Under the if-converted method, the weighted-average number of subordinated units outstanding for the period is added to the weighted-average number of common units outstanding for purposes of computing basic net income per unit and the resulting amount is compared to the diluted net income per unit computed using the two-class method. The following is a reconciliation of net income from continuing operations and net income from discontinued operations allocated to the general partner and limited partners for purposes of calculating net income

attributable to limited partners per unit:

	Years Ended December 31,		
	2013	2012	2011
Continuing operations:			
Net income (loss) attributable to Martin Midstream Partners L.P.	$(13,354)	$37,122	$13,367
Less pre-acquisition income (loss) allocated to Parent	—	4,622	(1,583)
Less general partner's interest in net income:			
Distributions payable on behalf of IDRs	—	954	2,878
Distributions payable on behalf of general partner interest	1,853	522	789
Distributions payable to the general partner interest in excess of earnings allocable to the general partner interest	(2,120)	109	(561)
Less loss allocable to unvested restricted units	(40)	—	—
Less beneficial conversion feature	—	—	651
Limited partners' interest in net income (loss)	$(13,047)	$30,915	$11,193

	Years Ended December 31,		
	2013	2012	2011
Discontinued operations:			
Net income attributable to Martin Midstream Partners L.P.	$—	$64,865	$9,392
Less general partner's interest in net income:			
Distributions payable on behalf of IDRs	—	1,903	2,023
Distributions payable on behalf of general partner interest	—	1,040	555
Distributions payable to the general partner interest in excess of earnings allocable to the general partner interest	—	220	(395)
Less beneficial conversion feature	—	—	457
Limited partners' interest in net income	$—	$61,702	$6,752

The Partnership allocates the general partner's share of earnings between continuing and discontinued operations as a proportion of net income from continuing and discontinued operations to total net income.

The weighted average units outstanding for basic net income per unit were 26,557,829, 23,361,551 and 19,545,427 for the years ended December 31, 2013, 2012 and 2011, respectively. All outstanding units were included in the computation of diluted earnings per unit and weighted based on the number of days such units were outstanding during the period presented. All common unit equivalents were antidilutive for the year ended December 31, 2013 because the limited partners were allocated a net loss in this period. For diluted net income per unit, the weighted average units outstanding were increased by 3,018 and 1,278 for the years ended December 31, 2012 and 2011, respectively, due to the dilutive effect of restricted units granted under the Partnership's long-term incentive plan.

(17) Unit Based Awards

The Partnership recognizes compensation cost related to stock-based awards to employees in its consolidated financial statements in accordance with certain provisions of ASC 718. The Partnership recognizes compensation costs related to stock-based awards to directors under certain provisions of ASC 505-50-55 related to equity-based payments to non-employees. Amounts recognized in selling, general, and administrative expense in the consolidated financial statements with respect to these plans are as follows:

	For the Year Ended December 31,		
	2013	2012	2011
Employees	$668	$178	$69
Non-employee directors	243	207	121
Total unit-based compensation expense	$911	$385	$190

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Long-Term Incentive Plans

The Partnership's general partner has a long term incentive plan for employees and directors of the general partner and its affiliates who perform services for the Partnership.

The plan consists of two components, restricted units and unit options. The plan currently permits the grant of awards covering an aggregate of 725,000 common units, 241,667 of which may be awarded in the form of restricted units and 483,333 of which may be awarded in the form of unit options. The plan is administered by the compensation committee of the general partner's board of directors ("Compensation Committee").

Restricted Units. A restricted unit is a unit that is granted to grantees with certain vesting restrictions. Once these restrictions lapse, the grantee is entitled to full ownership of the unit without restrictions. In addition, the restricted units will vest upon a change of control of the Partnership, the general partner or Martin Resource Management or if the general partner ceases to be an affiliate of Martin Resource Management. The Partnership intends the issuance of the common units upon vesting of the restricted units under the plan to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, plan participants will not pay any consideration for the common units they receive, and the Partnership will receive no remuneration for the units. The restricted units issued to directors generally vest in equal annual installments over a four-year period. Restricted units issued to employees generally cliff vest after three years of service.

The restricted units are valued at their fair value at the date of grant which is equal to the market value of common units on such date. A summary of the restricted unit activity for the year ended December 31, 2013 is provided below:

	Number of Units	Weighted Average Grant-Date Fair Value Per Unit
Non-vested, beginning of period	13,248	$39.30
Granted	64,500	$32.34
Vested	(4,500)	$38.99
Forfeited	(250)	$31.06
Non-Vested, end of period	72,998	$33.20
Aggregate intrinsic value, end of period	$3,124	

A summary of the restricted units' aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) during the years ended December 31, 2013, 2012 and 2011 is provided below:

	For the Year Ended December 31,		
	2013	2012	2011
Aggregate intrinsic value of units vested	$153	$465	$111
Fair value of units vested	$157	$495	$111

As of December 31, 2013, there was $1,626 of unrecognized compensation cost related to non-vested restricted units. That cost is expected to be recognized over a weighted-average period of 2.1 years.

Unit Options. The plan currently permits the grant of options covering common units. As of March 3, 2014, the Partnership has not granted any common unit options to directors or employees of the Partnership's general partner, or

its affiliates. In the future, the Compensation Committee may determine to make grants under the plan to employees and directors containing such terms as the Compensation Committee shall determine. Unit options will have an exercise price that, in the discretion of the Compensation Committee, may not be less than the fair market value of the units on the date of grant. In addition, the unit options will become exercisable upon a change in control of the Partnership's general partner, Martin Resource Management or if the general partner ceases to be an affiliate of Martin Resource Management or upon the achievement of specified financial objectives.

(18) Stanolind Tank Damage

During the third quarter of 2011, a single tank fire occurred at the Partnership's Stanolind Terminal in Beaumont, Texas. This specific tank stores No. 6 oil for Martin Resource Management under a throughput agreement. The tank contained approximately 3,200 barrels of No. 6 oil at the time the incident occurred, all of which was the property of Martin Resource Management.

Physical damage to the Partnership's asset caused by the fire as well as the related removal and recovery costs, are fully covered by the Partnership's non-windstorm insurance policy subject to a deductible of $443, which has been expensed and included in "operating expenses" in the Consolidated Statements of Operations for the year ended December 31, 2011.

Insurance proceeds received as a result of the this claim were used to replace the tank. The proceeds received exceeded the net book value of the tank that was destroyed and the Partnership recognized a gain in the amount of $909 in "other operating income" the Consolidated Statements of Operations for the year ended December 31, 2013.

(19) Income Taxes

The operations of a partnership are generally not subject to income taxes because its income is taxed directly to its partners, except as discussed below.

The activities of the Blending and Packaging Assets prior to the acquisition by the Partnership were subject to federal and state income taxes. Accordingly, income taxes have been included in the Blending and Packaging Assets' operating results from January 1, 2010 through October 2, 2012. Related payables/receivables are included in "Due to affiliates" and "Other current assets", respectively, in the Consolidated Balance Sheet.

Woodlawn, a subsidiary of the Partnership, was subject to income taxes due to its corporate structure. The assets of Woodlawn were sold July 31, 2012 and the corporation was liquidated December 31, 2012. Income tax expense related to Woodlawn is recorded in discontinued operations. A current federal income tax expense of $0, $8,681 and $11, related to the operation of the subsidiary, was recorded for the years ended December 31, 2013, 2012 and 2011, respectively.

The Partnership established deferred income taxes of $8,964 associated with book and tax basis differences of the acquired Woodlawn assets and liabilities at the date of acquisition. The basis differences related primarily to property, plant and equipment. A deferred tax benefit of $0, $7,657 and $139 related to the Woodlawn basis differences was recorded for the years ended December 31, 2013, 2012 and 2011, respectively. A deferred tax expense of $0, $402, and $622 related to the Cross basis differences was recorded for the years ended December 31, 2013, 2012 and 2011. No deferred tax liability related to these basis differences existed at December 31, 2013 and 2012, respectively. The deferred tax liability related to the Prism Assets was reversed upon the sale of those assets as discussed further in Note 5.

Effective January 1, 2007, the Partnership became subject to the Texas margin tax, which is considered a state income tax, and is included in income tax expense on the Consolidated Statements of Operations. The Texas margin tax restructured the state business tax by replacing the taxable capital and earned surplus components of the existing franchise tax with a new "taxable margin" component. Since the tax base on the Texas margin tax is derived from an income-based measure, the margin tax is construed as an income tax and, therefore, the recognition of deferred taxes applies to the margin tax. The impact on deferred taxes as a result of this provision is immaterial. State income taxes attributable to the Texas margin tax of $753, $1,575 and $713 were recorded in income tax expense for the years ended December 31, 2013, 2012 and 2011, respectively.

A current income tax liability of $1,204, and $10,239 existed at December 31, 2013 and 2012, respectively.

The components of income tax expense from operations recorded for the years ended December 31, 2013, 2012 and 2011 are as follows:

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	2013	2012	2011
Current:			
Federal	$—	$10,516	$1,303
State	753	1,894	975
	753	12,410	2,278
Deferred:			
Federal	—	(7,255)	483
Total income tax expense	$753	$5,155	$2,761

Total income tax expense was allocated to continuing and discontinued operations as follows:

Income tax expense from continuing operations:

	2013	2012	2011
Current:			
Federal	$—	$1,835	$1,292
State	753	1,320	958
	753	3,155	2,250
Deferred:			
Federal	—	402	622
Total income tax expense from continuing operations	$753	$3,557	$2,872

Income tax expense (benefit) from discontinued operations:

	2013	2012	2011
Current:			
Federal	$—	$8,681	$11
State	—	574	17
	—	9,255	28
Deferred:			
Federal	—	(7,657)	(139)
Total income tax expense (benefit) from discontinued operations	$—	$1,598	$(111)

Cash paid for income taxes was $9,789, $1,007, and $827 for the years ended December 31, 2013, 2012, and 2011, respectively.

(20) Business Segments

The Partnership has four reportable segments: terminalling and storage, natural gas services, marine transportation, and sulfur services. The Partnership's reportable segments are strategic business units that offer different products and services. The operating income of these segments is reviewed by the chief operating decision maker to assess performance and make business decisions.

The accounting policies of the operating segments are the same as those described in Note 2. The Partnership evaluates the performance of its reportable segments based on operating income. There is no allocation of administrative expenses or interest expense.

The Natural Gas Services segment information below excludes the discontinued operations of the Prism Assets for 2012 and 2011. See Note 5.

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	Operating Revenues	Intersegment Eliminations	Operating Revenues After Eliminations	Depreciation and Amortization	Operating Income (Loss) after Eliminations	Capital Expenditures
Year Ended December 31, 2013:						
Terminalling and storage	$341,966	$(4,756)	$337,210	$31,823	$32,855	$84,582
Natural gas services	987,681	—	987,681	2,240	31,733	4,080
Sulfur services	213,124	—	213,124	7,979	21,511	3,867
Marine transportation	99,510	(4,015)	95,495	10,198	13,410	6,517
Indirect selling, general, and administrative	—	—	—	—	(16,837)	—
Total	$1,642,281	$(8,771)	$1,633,510	$52,240	$82,672	$99,046
Year Ended December 31, 2012:						
Terminalling and storage	$322,175	$(4,652)	$317,523	$22,976	$25,403	$72,877
Natural gas services	825,506	—	825,506	601	15,395	434
Sulfur services	261,584	—	261,584	7,371	41,909	11,477
Marine transportation	88,815	(3,067)	85,748	11,115	3,174	8,852
Indirect selling, general, and administrative	—	—	—	—	(12,046)	—
Total	$1,498,080	$(7,719)	$1,490,361	$42,063	$73,835	$93,640
Year Ended December 31, 2011:						
Terminalling and storage	$283,175	$(4,414)	$278,761	$19,814	$20,619	$48,287
Natural gas services	611,749	—	611,749	578	7,487	620
Sulfur services	275,044	—	275,044	6,725	34,595	16,158
Marine transportation	83,971	(7,035)	76,936	13,159	(6,485)	12,137
Indirect selling, general, and administrative	—	—	—	—	(8,864)	—
Total	$1,253,939	$(11,449)	$1,242,490	$40,276	$47,352	$77,202

Revenues from two customers in the Natural Gas Services segment were $284,872, $294,508 and $258,542 for the years ended December 31, 2013, 2012 and 2011, respectively. Revenues from one customer in the Sulfur Services segment were $66,653, $87,820 and $111,172 for the years ended December 31, 2013, 2012 and 2011, respectively.

The Partnership's assets by reportable segment as of December 31, 2013 and 2012, are as follows:

	2013	2012
Total assets:		
Terminalling and storage	$461,160	$376,330
Natural gas services	320,631	331,064
Sulfur services	151,982	155,639
Marine transportation	164,146	149,963

Total assets	$1,097,919	$1,012,996

(21) Quarterly Financial Information

MARTIN MIDSTREAM PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in thousands, except where otherwise indicated)

Consolidated Quarterly Income Statement Information

	(Unaudited)			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(Dollar in thousands, except per unit amounts)			
2013				
Revenues	$433,686	$358,188	$359,616	$482,020
Operating income	26,385	20,259	12,243	23,785
Equity in earnings (loss) of unconsolidated entities	(374)	73	(577)	(52,170)
Net income (loss)	$16,637	$9,078	$192	$(39,261)
Limited partners' interest in net income (loss) per limited partner unit	$0.61	$0.33	$0.01	$(1.44)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(Dollar in thousands, except per unit amounts)			
2012				
Revenues	$348,326	$333,846	$354,090	$454,099
Operating income	19,781	19,215	16,246	18,593
Equity in earnings (loss) of unconsolidated entities	233	799	(775)	(1,370)
Income from continuing operations	10,742	8,044	8,646	9,690
Income (loss) from discontinued operations	1,725	1,984	63,603	(2,447)
Net income	$12,467	$10,028	$72,249	$7,243
Limited partners' interest in net income per limited partner unit	$0.39	$0.25	$3.07	$0.29

(22) Commitments and Contingencies

From time to time, the Partnership is subject to various claims and legal actions arising in the ordinary course of business. In the opinion of management, the ultimate disposition of these matters will not have a material adverse effect on the Partnership.

(23) Condensed Consolidating Financial Information

Martin Operating Partnership L.P. (the “Operating Partnership”), the Partnership’s wholly-owned subsidiary, has issued in the past, and may issue in the future, unconditional guarantees of senior or subordinated debt securities of the Partnership in the event that the Partnership issues such securities from time to time. The guarantees that have been issued are full, irrevocable and unconditional. In addition, the Operating Partnership may also issue senior or subordinated debt securities which, if issued, will be fully, irrevocably and unconditionally guaranteed by the Partnership.

Since December 31, 2012, the Partnership has added Redbird and MOP Midstream Holdings LLC as subsidiary guarantors to its outstanding senior unsecured notes and has transferred substantially all of Talen's assets to certain of the Partnership's other subsidiary guarantors. Therefore, the Partnership no longer presents condensed consolidating financial information for any non-subsidiary guarantors.

(24) Subsequent Events

Redemption of 2018 Senior Unsecured Notes. On February 28, 2014, the Partnership announced that it will exercise a full redemption of the 2018 senior unsecured notes pursuant to the indenture, on or about April 1, 2014 at an aggregate redemption value of $182,767. The Partnership expects to fund the redemption under borrowings from our revolving credit facility.

Amendment to Revolving Credit Facility. On February 18, 2014, the Partnership increased the maximum amount of borrowings under its revolving credit facility from $600,000 to $637,500 by utilizing the accordion feature of the Partnership's revolving credit facility.

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Quarterly Distribution. On January 23, 2014, The Partnership declared a quarterly cash distribution of $0.785 per common unit for the fourth quarter of 2013, or $3.14 per common unit on an annualized basis, which was paid on February 14, 2014 to unitholders of record as of February 7, 2014.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

(a) Evaluation of Disclosure Controls and Procedures. In accordance with Rules 13a-15 and 15d-15 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), we, under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer of our general partner, carried out an evaluation of the effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15(d)-15(e) of the Exchange Act) as of December 31, 2013. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of our general partner concluded that our disclosure controls and procedures were effective as of December 31, 2013.

(b) Management's Report on Internal Control Over Financial Reporting. Management is responsible for establishing and maintaining adequate internal control over financial reporting. Our management, including the Chief Executive Officer and Chief Financial Officer of our general partner, conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation under the framework in Internal Control — Integrated Framework (1992), our management concluded that our internal control over financial reporting was effective as of December 31, 2013. The effectiveness of our internal control over financial reporting as of December 31, 2013 has been audited by KPMG LLP, our independent registered public accounting firm, as stated in their report appearing in "Item 8 - Financial Statements and Supplementary Data."

There were no changes in our internal controls over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act) that occurred during our most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Item 9B. Other Information

None

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Management of Martin Midstream Partners L.P.

Martin Midstream GP LLC, as our general partner, manages our operations and activities on our behalf. Our general partner was not elected by our unitholders and will not be subject to re-election in the future. Unitholders do not directly or indirectly participate in our management or operation. Our general partner owes a fiduciary duty to our unitholders. Our general partner is liable, as general partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically non-recourse to it. However, whenever possible, our general partner seeks to provide that our indebtedness or other obligations are non-recourse to our general partner.

Three directors of our general partner serve on a conflicts committee of the Partnership's general partner ("Conflicts Committee") to review specific matters that the directors believe may involve conflicts of interest. The Conflicts Committee determines if the resolution of the conflict of interest is fair and reasonable to us. The members of the Conflicts Committee may not be officers or employees of our general partner or directors, officers, or employees of its affiliates and must meet the independence standards established by NASDAQ to serve on an audit committee of a board of directors; provided, however that a director with a family member who is a partner with a foreign affiliate in the international cooperative of our registered independent public accounting firm shall be deemed to meet such independence standards if such director meets all other independence standards of NASDAQ and the board of our general partner affirmatively determines that such family relationship will not impair such director's independent judgment as a member of the Conflicts Committee. Any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners, and not a breach by our general partner of any duties it may owe us or our unitholders. The current members of our Conflicts Committee are outside directors, Joe N. Averett, Jr., C. Scott Massey and Charles H. Still, all of whom meet the independence standards established by NASDAQ, except as referenced above.

The Audit Committee reviews our external financial reporting, recommends engagement of our independent auditors and reviews procedures for internal auditing and the adequacy of our internal accounting controls. The current members of our Audit Committee are outside directors, C. Scott Massey, Byron R. Kelley and Charles H. Still, all of whom meet the independence standards established by NASDAQ.

The Compensation Committee oversees compensation decisions for the officers of our general partner as well as the compensation plans described below. The current members of our Compensation Committee are our outside directors, Joe N. Averett, Jr., C. Scott Massey, Byron R. Kelley and Charles H. Still.

The current members of our Nominating Committee are outside directors, Joe N. Averett, Jr, Byron R. Kelley and Charles H. Still.

We are managed and operated by the directors and officers of our general partner. All of our operational personnel are employees of Martin Resource Management. All of the officers of our general partner will spend a substantial amount of time managing the business and affairs of Martin Resource Management and its other affiliates. These officers may face a conflict regarding the allocation of their time between our business and the other business interests of Martin Resource Management. Our general partner intends to cause its officers to devote as much time to the management of our business and affairs as is necessary for the proper conduct of our business and affairs.

Directors and Executive Officers of Martin Midstream GP LLC

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The following table shows information for the directors and executive officers of our general partner. Directors and executive officers are elected for one-year terms.

Name	Age	Position with the General Partner
Ruben S. Martin	62	President, Chief Executive Officer and Director
Robert D. Bondurant	55	Executive Vice President and Chief Financial Officer
Randall L. Tauscher	48	Executive Vice President and Chief Operating Officer
Wesley M. Skelton	66	Executive Vice President, Chief Administrative Officer and Controller
Chris Booth	44	Executive Vice President, General Counsel and Secretary
C. Scott Massey	61	Director
Joe N. Averett, Jr.	71	Director
Charles H. Still	71	Director
Byron R. Kelley	66	Director
Alexander W.F. Black	46	Director
Sean P. Dolan	40	Director

Ruben S. Martin serves as President, Chief Executive Officer and a member of the board of directors of our general partner. Mr. Martin has served in such capacities since June 2002. Mr. Martin has served as President of Martin Resource Management since 1981 and has served in various capacities within the company since 1974. Mr. Martin holds a Bachelor of Science degree in industrial management from the University of Arkansas. Mr. Martin was selected to serve as a director on our general partner's board of directors due to his depth of knowledge of the Partnership, including its strategies, its operations, his business judgment and his position within the Partnership.

Robert D. Bondurant serves as Executive Vice President and Chief Financial Officer of our general partner. Mr. Bondurant has served in such capacities since June 2002. Mr. Bondurant joined Martin Resource Management in 1983 as Controller and subsequently was appointed Chief Financial Officer and a member of its board of directors in 1990. Mr. Bondurant served in the audit department at Peat Marwick, Mitchell and Co from 1980 to 1983. Mr. Bondurant holds a Bachelor of Business Administration degree in accounting from Texas A&M University and is a Certified Public Accountant, licensed in the State of Texas.

Randall L. Tauscher serves as Executive Vice President and Chief Operating Officer of our general partner. Mr. Tauscher has served in this capacity since August 2011. From November 2007 through July 2011, Mr. Tauscher served as Executive Vice President. Prior to joining Martin, Mr. Tauscher was employed by Koch Industries for over 18 years, most recently as Senior Vice President of the Koch Carbon Division. Mr. Tauscher earned a Bachelor of Business Administration degree from Kansas State University.

Wesley M. Skelton serves as Executive Vice President, Controller and Chief Administrative Officer of our general partner. Mr. Skelton has served in such capacities since June 2002. Mr. Skelton joined Martin Resource Management in 1981 and has served as Chief Administrative Officer since 1981 and a Director since 1990. Prior to joining Martin Resource Management, Mr. Skelton served as Treasurer of First Federal Savings & Loan, Marshall, Texas from January 1977 through January 1981 and was employed by Peat Marwick, Mitchell & Co. from August 1973 through January 1977. Mr. Skelton holds a Bachelor of Business Administration degree from the University of Texas and is a Certified Public Accountant licensed in the State of Texas.

Chris Booth serves as Executive Vice President, General Counsel and Secretary of our general partner. Mr. Booth has served as an officer of our general partner since February 2006. Mr. Booth joined Martin Resource Management in October 2005. Prior to joining Martin Resource Management, Mr. Booth was an attorney with the law firm of Mehaffy Weber located in Beaumont, Texas. Mr. Booth holds a Doctor of Jurisprudence degree and a Masters of Business Administration degree with a concentration in finance from the University of Houston. Additionally, Mr. Booth holds a Bachelor of Science degree in business management from LeTourneau University. Mr. Booth is an

attorney licensed to practice in the State of Texas.

C. Scott Massey serves as a member of the board of directors of our general partner. Mr. Massey has served as a Director since June 2002. Mr. Massey has been self employed as a Certified Public Accountant since 1998. From 1977 to 1998, Mr. Massey worked for KPMG Peat Marwick, LLP in various positions, including, most recently, as a Partner in the firm's Tax Practice - Energy, Real Estate, Timber from 1986 to 1998. Mr. Massey received a Bachelor of Business Administration degree from the University of Texas at Austin and a Doctor of Jurisprudence degree from the University of Houston. Mr. Massey is a Certified Public Accountant, licensed in the states of Louisiana and Texas. Mr. Massey was selected

to serve as a director on our general partner's board of directors due to his extensive background in public accounting and taxation. Mr. Massey qualifies as an “audit committee financial expert” under the SEC guidelines.

Joe N. Averett, Jr. serves as a member of the board of directors of our general partner. Mr. Averett has served as a Director since June 2010. Mr. Averett has served on the board of directors of Penn Virginia Corporation and Capital One Mutual Funds. He was the President and Chief Executive Officer of Crystal Gas Storage, Inc., a provider of natural gas storage, from 1985 to 2003. Prior to joining Crystal Gas Storage, Inc., Mr. Averett was the Chief Financial Officer of P&O Falco, Inc. and Langham Petroleum. Mr. Averett was also the Treasurer and Chief Financing Officer for the Pennzoil Company. Mr. Averett has also served in Washington, D.C., as the United States Presidential Executive in the Treasury Department, Office of the Secretary, tasked with economic policy. Mr. Averett holds a Bachelor of Business Administration degree in finance from Texas A&M University. Mr. Averett was selected to serve as a director on our general partner's board of directors due to his extensive business experience.

Charles H. Still serves as a member of the Board of Directors of our general partner. Mr. Still has served as a Director since July 2011. Mr. Still was a partner in the law firm Kelly Hart & Hallman LLP from June 2008 until his retirement in December 2010. Prior to joining Kelly Hart & Hallman LLP in 2008, Mr. Still was an associate and partner in the law firm Fulbright & Jaworski L.L.P. from 1968 until his retirement in 2007. He was of counsel to Fulbright & Jaworski from January 1, 2009 to June 20, 2009 and again became of counsel to Fulbright & Jaworski on February 28, 2012, but that relationship ended December 31, 2013. Mr. Still is currently on the board of directors of Geospace Technologies Inc. Mr. Still holds a J.D. from the University of Texas School of Law and a B.B.A. in accounting from Texas Tech University. He served as an Adjunct Professor of Law at the University of Texas School of Law from 2007 through 2010.

Byron R. Kelley serves as a member of the board of directors of our general partner and also served as an Advisory Director from April 2011 to August 2012. On December 31, 2013, Mr. Kelley retired as CEO, President and a member of the board of directors of CVR Partners, LP, a chemical company engaged in the production of nitrogen based fertilizers and served in this position from June 2011 through December 2013. Prior to joining CVR Partners in June of 2011 he served as President, Chief Executive Officer and a member of the board of directors of Regency GP, LLC from April 2008 to November 2010. From 2004 through March of 2008, Mr. Kelley served as Senior Vice President and Group President of Pipeline and Field Services at CenterPoint Energy. Preceding his work at CenterPoint, Mr. Kelley served as Executive Vice President of Development, Operations and Engineering, and as President of El Paso Energy International. Mr. Kelley is a past member and Chairman of the board of directors of the Interstate National Gas Association and previously served as one of the association's representatives on the United States Natural Gas Council of America. Mr. Kelley received a Bachelor of Science degree in civil engineering from Auburn University. Mr. Kelley was selected to serve as a director on our general partner's board of directors due to his extensive corporate business experience.

Alexander W.F. Black serves as a member of the board of directors of our general partner. Mr. Black has served as a Director since September 2013. Mr. Black is a partner at Alinda Capital Partners, which he joined in 2008. Prior to joining Alinda, he was a senior director of Kroll Zolfo Cooper, LLC, a consulting firm based in New York. Mr. Black has been CEO, CFO or head of operations at several businesses in the United States and United Kingdom. Prior to that, he was an audit supervisor at Touche Ross & Co. He is a Chartered Engineer, Chartered Insolvency and Restructuring Advisor, and a Chartered Accountant. He has a BSc (Hons) degree from Exeter University, United Kingdom. Mr. Black was selected to serve as a director on our general partner's board of directors due to his affiliation with Alinda, his knowledge of the energy industry and his financial, business and operational experience.

Sean P. Dolan serves as a member of the board of directors of our general partner. Mr. Dolan has served as a Director since September 2013. Mr. Dolan is a Managing Director of Alinda Capital Partners, which he joined in 2009. Prior to joining Alinda, Mr. Dolan spent over 12 years with Citigroup Global Markets in investment banking primarily

focused in the energy sector. Mr. Dolan received a bachelor's degree from Georgetown University. Mr. Dolan was selected to serve as a director on our general partner's board of directors due to his affiliation with Alinda, his knowledge of the energy industry and his financial and business expertise.

Independence of Directors

Messrs. Massey, Still, Averett, and Kelley qualify as “independent” in accordance with the published listing requirements of NASDAQ and applicable securities laws. The NASDAQ independence definition includes a series of objective tests, such as that the director is not an employee of us and has not engaged in various types of business dealings with us. In addition, as further required by the NASDAQ rules, the board of directors has made a subjective determination as to each independent director that no relationships exist which, in the opinion of the board, would interfere with the exercise of independent judgment in carrying out the responsibilities of a director. In making these determinations, the directors reviewed

and discussed information provided by the directors and us with regard to each director's business and personal activities as they may relate to us and our management.

Board Meetings and Committees

From January 1, 2013 to December 31, 2013, the board of directors of our general partner held 14 meetings. All directors then in office attended each of these meetings, either in person, by teleconference or by videoconference with the exception of Byron R. Kelley, who was not in attendance at the meeting of the board of directors on the date of March 26, 2013, Joe N. Averett, Jr., who was not in attendance at the meeting of the board of directors on the date of August 18, 2013, and Sean Dolan, who was not in attendance at the meeting of the board of directors on the date of December 19, 2013. Additionally, the board of directors undertook action one time during 2013 without a meeting by acting through written unanimous consent. We have standing conflicts, audit, compensation and nominating committees of the board of directors of our general partner. The board of directors of our general partner appoints the members of the Audit, Compensation, Nominating and Conflicts Committees. Each member of the Audit Committee is an independent director in accordance with NASDAQ and applicable securities laws. Each of the board committees has a written charter approved by the board. Copies of each charter are posted on our website at www.martinmidstream.com under the “Corporate Governance” section. The current members of the committees, the number of meetings held by each committee from January 1, 2013 to December 31, 2013, and a brief description of the functions performed by each committee are set forth below:

Conflicts Committee (6 meetings). The members of the Conflicts Committee are Messrs. Averett (chairman), Massey and Still. All of the members of the Conflicts Committee attended all meetings of the committee for the period noted above. The primary responsibility of the Conflicts Committee is to review matters that the directors believe may involve conflicts of interest. The Conflicts Committee determines if the resolution of the conflict of interest is fair and reasonable to us. The members of the Conflicts Committee may not be officers or employees of our general partner or directors, officers, or employees of its affiliates and must meet the independence standards to serve on an audit committee of a board of directors established by NASDAQ; provided, however that a director with a family member who is a partner with a foreign affiliate in the international cooperative of our registered independent public accounting firm shall be deemed to meet such independence standards if such director meets all other independence standards of NASDAQ and the board of our general partner affirmatively determines that such family relationship will not impair such director's independent judgment as a member of the Conflicts Committee. Any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners, and not a breach by our general partner of any duties it may owe us or our unitholders.

Audit Committee (4 meetings). Additionally, the Audit Committee undertook action one time during 2013 without a meeting by acting through written unanimous consent. The members of the Audit Committee are Messrs. Massey (chairman), Still and Kelley. All of the members attended all meetings of the Audit Committee for the period noted above. The primary responsibilities of the Audit Committee are to assist the board of directors in its general oversight of our financial reporting, internal controls and audit functions, and it is directly responsible for the appointment, retention, compensation and oversight of the work of our independent auditors. The members of the Audit Committee of the board of directors of our general partner each qualify as “independent” under standards established by the SEC for members of Audit Committees, and the Audit Committee includes at least one member who is determined by the board of directors to meet the qualifications of an “audit committee financial expert” in accordance with SEC rules, including that the person meets the relevant definition of an “independent” director. C. Scott Massey is the independent director who has been determined to be an audit committee financial expert. Unitholders should understand that this designation is a disclosure requirement of the SEC related to Mr. Massey's experience and understanding with respect to certain accounting and auditing matters. The designation does not impose on Mr. Massey any duties, obligations or

liability that are greater than are generally imposed on him as a member of the Audit Committee and board of directors, and his designation as an audit committee financial expert pursuant to this SEC requirement does not affect the duties, obligations or liability of any other member of the Audit Committee or board of directors.

Compensation Committee (3 meetings). The members of the Compensation Committee are Messrs. Kelley (chairman), Massey, Still and Averett. All of the members attended all meetings of the Compensation Committee for the period noted above. The primary responsibility of the Compensation Committee is to oversee compensation decisions for the outside directors of our general partner and executive officers of our general partner (in the event they are to be paid by our general partner) as well as our long-term incentive plan.

Nominating Committee (1 meeting). The members of the nominating committee are Messrs. Still (chairman), Averett and Kelley. All of the members attended all meetings of the Compensation Committee for the period noted above. The primary responsibility of the nominating committee is to select and recommend nominees for election to the board of directors of our general partner.

Code of Ethics and Business Conduct

Our general partner has adopted a Code of Ethics and Business Conduct applicable to all of our general partner's employees (including any employees of Martin Resource Management who undertake actions with respect to us or on our behalf), including all officers, and including our general partner's independent directors, who are not employees of our general partner, with regard to their activities relating to us. The Code of Ethics and Business Conduct incorporate guidelines designed to deter wrongdoing and to promote honest and ethical conduct and compliance with applicable laws and regulations. They also incorporate our expectations of our general partner's employees (including any employees of Martin Resource Management who undertake actions with respect to us or on our behalf) that enable us to provide accurate and timely disclosure in our filings with the Securities and Exchange Commission and other public communications. The Code of Ethics and Business Conduct is publicly available on our website under the "Corporate Governance" section (at www.martinmidstream.com). This website address is intended to be an inactive, textual reference only, and none of the material on this website is part of this report. If any substantive amendments are made to the Code of Ethics and Business Conduct or if we or our general partner grant any waiver, including any implicit waiver, from a provision of the code to any of our general partner's executive officers and directors, we will disclose the nature of such amendment or waiver on that website or in a report on Form 8-K.

Section 16(a) Beneficial Ownership Reporting Compliance

Our general partner's directors and officers and beneficial owners of more than 10% of a registered class of our equity securities are required to file reports of ownership and reports of changes in ownership with the SEC and NASDAQ. Directors, officers and beneficial owners of more than 10% of our equity securities are also required to furnish us with copies of all such reports that are filed. Based solely on our review of copies of such forms and amendments, we believe directors, officers and greater than 10% beneficial owners complied with all filing requirements during the year ended December 31, 2013, with the exception of the initial Form 3 for Sean P. Dolan and Alexander W.F. Black which were filed late.

Reimbursement of Expenses of our General Partner

Our general partner does not receive a management fee or other compensation for its management of our partnership. However, our general partner and its affiliates are reimbursed for expenses incurred on our behalf. All direct general and administrative expenses are charged to us as incurred. For the years ended December 31, 2013, 2012 and 2011, we reimbursed Martin Resource Management $177.1 million, $157.8 million and $142.0 million, respectively, for direct costs and expenses. There is no monetary limitation on the amount we are required to reimburse Martin Resource Management for direct expenses.

Indirect general and administrative and corporate overhead costs relate to centralized corporate functions that we share with Martin Resource Management, including certain accounting, treasury, engineering, information technology, insurance, administration of employee benefit plans and other corporate services. In addition to the direct expenses, under the Omnibus Agreement, we are required to reimburse Martin Resource Management for indirect general and administrative and corporate overhead expenses. For the years ended December 31, 2013, 2012 and 2011, the Conflicts Committee approved reimbursement amounts of $10.6 million, $7.6 million and $4.8 million, respectively, reflecting our allocable share of such expenses. The Conflicts Committee will review and approve future adjustments

in the reimbursement amount for indirect expenses, if any, annually.

Our partnership agreement provides that our general partner will determine the expenses that are allocable to us in any reasonable manner determined by our general partner in its sole discretion. Please read "Item 13. Certain Relationships and Related Transactions, and Director Independence — Agreements — Omnibus Agreement."

Item 11. Executive Compensation

Compensation Discussion and Analysis

Background

We are required to provide information regarding the compensation program in place as of December 31, 2013, for the CEO, CFO and the three other most highly-compensated executive officers of our general partner as reflected in the summary compensation table set forth below (the "Named Executive Officers"). This section should be read in conjunction with the detailed tables and narrative descriptions regarding compensation below.

We are a master limited partnership and have no employees. We are managed by the executive officers of our general partner. These executive officers are employed by Martin Resource Management, a private corporation that has significant operations that are separate from ours. The executive officers of our general partner are also the executive officers of Martin Resource Management and devote significant time to the management of Martin Resource Management's operations. We reimburse Martin Resource Management for a portion of the indirect general and administrative expenses, including compensation expense relating to the service of these individuals that are allocated to us pursuant to the omnibus agreement between us and our general partner, as amended on October 1, 2012 ("Omnibus Agreement"). Under the Omnibus Agreement, we are required to reimburse Martin Resource Management for indirect general and administrative and corporate overhead expenses. For the years ended December 31, 2013, 2012 and 2011, the conflicts committee of our general partner ("Conflicts Committee") approved reimbursement amounts of $10.6 million, $7.6 million and $4.8 million, respectively, reflecting our allocable share of such expenses. Please see "Item 13. Certain Relationships and Related Transactions, and Director Independence — Agreements — Omnibus Agreement" for a discussion of the Omnibus Agreement.

Compensation Objectives

As we do not directly compensate the executive officers of our general partner, we do not have any set compensation programs. The elements of Martin Resource Management's compensation program discussed below, along with Martin Resource Management's other rewards, are intended to provide a total rewards package designed to yield competitive total cash compensation, drive performance and reward contributions in support of the businesses of Martin Resource Management and other Martin Resource Management affiliates, including us, for which the Named Executive Officers perform services. Although we bear an allocated portion of Martin Resource Management's costs of providing compensation and benefits to the Named Executive Officers, we do not have control over such costs and do not establish or direct the compensation policies or practices of Martin Resource Management. During 2013, Martin Resource Management paid compensation based on the performance of Martin Resource Management but did not set any specific performance-based criteria and did not have any other specific performance-based objectives.

Elements of Compensation

Martin Resource Management's executive officer compensation package includes a combination of annual cash, long-term incentive compensation and other compensation. Elements of compensation which the Named Executive Officers may be eligible to receive from Martin Resource Management consist of the following: (1) annual base salary; (2) discretionary annual cash awards; (3) awards pursuant to Martin Resource Management employee benefit plans and (4) where appropriate, other compensation, including limited perquisites.

Annual Base Salary. Base salary is intended to provide fixed compensation to the Named Executive Officers for their performance of core duties with respect to Martin Resource Management and its affiliates, including us, and to compensate for experience levels, scope of responsibility and future potential. Base salaries are not intended to

compensate individuals for extraordinary performance or for above average company performance. The base salaries of the Named Executive Officers are reviewed on an annual basis, as well as at the time of promotion and other changes in responsibilities or market conditions.

Discretionary Annual Cash Awards. In addition to the annual base salary, the Named Executive Officers may be eligible to receive discretionary annual cash awards that, if awarded, are paid in a lump sum in the quarter following the end of the fiscal year. These cash awards are designed to provide the Named Executive Officers with competitive incentives to help drive performance and promote achievement of Martin Resource Management's business objectives. Named Executive Officers may also be eligible to receive a cash award based upon their services provided to us in the event that any such Named Executive Officer has devoted a significant amount of their time to working for us. Any such award is determined in

accordance with the same methodologies as the discretionary annual cash awards for Martin Resource Management, as described below.

Employee Benefit Plan Awards. The Named Executive Officers may be eligible to receive awards pursuant to the Martin Midstream Partners L.P. Long-Term Incentive Plan and Martin Resource Management employee benefit plans. These employee benefit plan awards are designed to reward the performance of the Named Executive Officers by providing annual incentive opportunities tied to the annual performance of Martin Resource Management. In particular, these awards are provided to the Named Executive Officers in order to provide competitive incentives to these executives who can significantly impact performance and promote achievement of the business objectives of Martin Resource Management.

Other Compensation. Martin Resource Management generally does not pay for perquisites for any of the Named Executive Officers, other than general recreational activities at certain Martin Resource Management's properties located in Texas, including aircraft. No perquisites are paid for services rendered to us. Martin Resource Management provides an executive life insurance policy and long term disability policy for the Named Executive Officers with the annual premiums being paid by Martin Resource Management. Martin Resource Management does not provide any greater allocation toward employee health insurance premiums than is provided for all other employees covered on the health benefits plan.

Compensation Methodology

The compensation policies and philosophy of Martin Resource Management govern the types and amount of compensation granted to each of the Named Executive Officers. The board of directors and Conflicts Committee do have responsibility for evaluating and determining the reasonableness of the total amount we are charged under the Omnibus Agreement for managerial, administrative and operational support, including compensation of the Named Executive Officers, provided by Martin Resource Management.

Our allocation for the costs incurred by Martin Resource Management in providing compensation and benefits to its employees who serve as the Named Executive Officers is governed by the Omnibus Agreement. In general, this allocation is based upon estimates of the relative amounts of time that these employees devote to the business and affairs of our general partner and to the business and affairs of Martin Resource Management. We bear substantially less than a majority of Martin Resource Management's costs of providing compensation and benefits to the Named Executive Officers.

When setting compensation for the Named Executive Officers, the elements of compensation above are considered holistically to provide an appropriate combination of compensation. Annual base salaries are determined by the Compensation Committee of Martin Resource Management following an individual performance review of each Named Executive Officer. Further, Martin Resource Management, with the approval of Mr. Ruben Martin, the Chief Executive Officer of Martin Resource Management, normally reviews market data and relevant compensation surveys when setting base compensation and, when appropriate, engages compensation consultants. Except in the case of an exceptional amount of time devoted to us, discretionary annual cash awards are based on the performance of Martin Resource Management. Annual discretionary cash awards, if any, are calculated first by allocating a portion of Martin Resource Management's earnings as determined by Martin Resource Management's Compensation Committee for distribution to key employees of Martin Resource Management. Upon such allocation, Mr. Martin with input from appropriate business leaders determines the allocation and distribution of the bonus pool among such employees, including the Named Executive Officers. With respect to employee benefit plan awards, Mr. Martin makes a recommendation to the Compensation Committee of Martin Resource Management as to whether such awards should be awarded to any employees. Any such employee plan awards are then approved by the Compensation Committee and distributed to the employees, including Named Executive Officers, accordingly.

Any awards granted under our long-term incentive plan, which to date have consisted of the grant of restricted common units to the independent directors and employees of our general partner, are approved by the Compensation Committee.

The Named Executive Officers who serve on the compensation committee of Martin Resource Management play a role in setting the compensation as base salaries, discretionary annual cash awards and employee benefit awards are set by that committee. Current members of the Martin Resource Management compensation committee are Mr. Ruben Martin, Chief Executive Officer, Mr. Robert Bondurant, Chief Financial Officer, Mr. Randall Tauscher, Chief Operating Officer, Mr. Wesley Skelton, Chief Administrative Officer and Controller and Mrs. Melanie Mathews, Vice President-Human Resources. Further, as is explained above, Mr. Martin, as Chief Executive Officer, also has significant authority in setting base salaries, discretionary annual cash award allocations and amounts and employee benefit award distributions.

Determination of 2013 Compensation Amounts

During 2013, elements of all compensation paid to the Named Executive Officers by Martin Resource Management consisted of the following: (1) annual base salary; (2) discretionary annual cash awards; (3) awards pursuant to Martin Resource Management employee benefit plans; and (4) other compensation, including limited perquisites. With respect to the Named Executive Officers, they were paid an allocated portion of their base salaries.

Annual Base Salary. The portions of the annual base salaries paid by Martin Resource Management to the Named Executive Officers, which are allocable to us under our Omnibus Agreement with Martin Resource Management, are reflected in the summary compensation table below. Based upon the agreement of our general partner with Martin Resource Management, we have reimbursed Martin Resource Management for approximately 51.1% of the aggregate annual base salaries paid to the Named Executive Officers by Martin Resource Management during 2013. The foregoing agreement has been developed based on an assessment of the estimated percentage of the time spent by the Named Executive Officers managing our affairs, relative to the affairs of Martin Resource Management ranging from approximately 30% to 67%. Our Named Executive Officers are Mr. Ruben Martin, the President and Chief Executive Officer of our general partner, Mr. Robert Bondurant, an Executive Vice President and Chief Financial Officer of our general partner, Mr. Wesley Skelton, an Executive Vice President, Controller and Chief Administrative Officer of our general partner, Mr. Randall Tauscher, an Executive Vice President and Chief Operating Officer of our general partner and Mr. Chris Booth, the Executive Vice President, General Counsel and Secretary of our general partner. Annual base salaries of the Named Executive Officers were not increased during 2013 by Martin Resource Management.

Discretionary Annual Cash Awards. Discretionary annual cash awards paid to the Named Executive Officers which are allocable to us are reflected in the summary compensation table below.

Martin Midstream Partners L.P. Long-Term Incentive Plan

Our general partner has adopted the Martin Midstream Partners L.P. Long-Term Incentive Plan (“LTIP”) for employees and directors of our general partner and its affiliates who perform services for us. The LTIP was amended in January 2006 to clarify the Partnership’s ability to grant restricted common units under the LTIP and to remove provisions relating to grants of distribution equivalent rights and phantom units.

The LTIP consists of two components, restricted units and unit options. The LTIP currently permits the grant of awards covering an aggregate of 725,000 common units, 241,667 of which may be awarded in the form of restricted units and 483,333 of which may be awarded in the form of unit options. The plan is administered by the Compensation Committee of our general partner’s board of directors.

Our general partner’s board of directors or the Compensation Committee, in their discretion, may terminate or amend the LTIP at any time with respect to any units for which a grant has not yet been made. Our general partner’s board of directors or the Compensation Committee also have the right to alter or amend the LTIP or any part of the plan from time to time, including increasing the number of units that may be reserved for issuance under the plan subject to any applicable unitholder approval. However, no change in any outstanding grant may be made that would materially impair the rights of the participant without the consent of the participant.

Restricted Units. A restricted unit is a unit that is granted to grantees with certain vesting restrictions. Once these restrictions lapse, the grantee is entitled to full ownership of the unit without restrictions. A phantom unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit, or in the discretion of the Compensation Committee, cash equivalent to the value of a common unit. The Compensation Committee may determine to make grants under the plan to employees and directors containing such terms as the Compensation Committee shall determine under the plan. The Compensation Committee will determine the period over which restricted units or

phantom units granted to employees and directors will vest. The committee may base its determination upon the achievement of specified financial objectives. In addition, the restricted units or phantom units will vest upon a change of control of us, our general partner or Martin Resource Management or if our general partner ceases to be an affiliate of Martin Resource Management.

If a grantee's employment or membership on the board of directors terminates for any reason, the grantee's restricted units or phantom units will be automatically forfeited unless, and to the extent, the Compensation Committee provides otherwise. Common units to be delivered upon the vesting of restricted units or phantom units may be common units acquired by our general partner in the open market, common units already owned by our general partner, common units acquired by our general partner directly from us or any affiliate of our general partner or any combination of the foregoing. Our general partner will be entitled to reimbursement by us for the cost incurred in acquiring common units. If we issue new common units upon vesting of the restricted units or phantom units, the total number of common units outstanding will increase.

We intend the issuance of the common units upon vesting of the restricted units or phantom units under the plan to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, plan participants will not pay any consideration for the common units they receive, and we will receive no remuneration for the units.

On April 29, 2013, we issued 1,500 restricted common units to each of our four independent directors under our LTIP. These restricted common units vest in equal installments of 375 units on January 24, 2014, 2015, 2016, and 2017.

On January 1, 2013, we issued 16,250 restricted common units to our Named Executive Officers which vest on January 1, 2016. The grant date fair value of these restricted units is reflected in the summary compensation table below.

On April 30, 2012, we issued 1,250 restricted common units to each of our four independent directors under our LTIP. These restricted common units vest in equal installments of 312.5 units on January 24, 2013, 2014, 2015, and 2016.

On May 2, 2011, we issued 1,250 restricted common units to a independent advisory director under our LTIP. These restricted common units vest in equal installments of 312.5 units on January 24, 2012, 2013, 2014 and 2015.

On February 28, 2011, we issued 1,250 restricted common units to each of four independent directors under our LTIP. These restricted common units vest in equal installments of 312.5 units on January 24, 2012, 2013, 2014 and 2015.

On August 2, 2010, we issued 1,500 restricted common units to each of two new independent, independent directors under our LTIP. These restricted common units vest in equal installments of 375 units and were fully vested on January 24, 2011, 2012, 2013 and 2014.

On May 3, 2010, we issued 1,000 restricted common units to each of our three independent, independent directors under our LTIP. These restricted common units vest in equal installments of 250 units and were fully vested on January 24, 2011, 2012, 2013 and 2014.

On August 3, 2009, we issued 1,000 restricted common units to each of its three independent, independent directors under its long-term incentive plan from treasury shares purchased by us in the open market for $78. These units vest in 25% increments beginning in January 2010 and were fully vested in January 2013.

On May 5, 2008, we issued 1,000 restricted common units to each of its three independent, independent directors under its long-term incentive plan from treasury shares purchased by us in the open market for $93. These units vest in 25% increments beginning in January 2009 and were fully vested in January 2012.

Unit Options. The LTIP currently permits the grant of options covering common units. As of March 3, 2014, we have not granted any common unit options to directors or employees of our general partner, or its affiliates. In the future, the Compensation Committee may determine to make grants under the plan to employees and directors containing such terms as the committee shall determine. Unit options will have an exercise price that, in the discretion of the committee, may not be less than the fair market value of the units on the date of grant. In general, unit options granted will become exercisable over a period determined by the Compensation Committee. In addition, the unit options will become exercisable upon a change in control of us, our general partner, Martin Resource Management or if our general partner ceases to be an affiliate of Martin Resource Management or upon the achievement of specified

financial objectives.

Upon exercise of a unit option, our general partner will acquire common units in the open market or directly from us or any affiliate of our general partner or use common units already owned by our general partner, or any combination of the foregoing. Our general partner will be entitled to reimbursement by us for the difference between the cost incurred by our general partner in acquiring these common units and the proceeds received by our general partner from an optionee at the time of exercise. Thus, the cost of the unit options will be borne by us. If we issue new common units upon exercise of the unit options, the total number of common units outstanding will increase, and our general partner will pay us the proceeds it received from the optionee.

Martin Resource Management Employee Benefit Plans

Martin Resource Management has employee benefit plans for its employees who perform services for us. The following summary of these plans is not complete but outlines the material provisions of these plans.

Martin Resource Management Purchase Plan for Units of Martin Midstream Partners L.P. Martin Resource Management maintains a purchase plan for our units to provide employees of Martin Resource Management and its affiliates who perform services for us the opportunity to acquire an equity interest in us through the purchase of our common units. Each individual employed by Martin Resource Management or an affiliate of Martin Resource Management that provides services to us is eligible to participate in the purchase plan. Enrollment in the purchase plan by an eligible employee will constitute a grant by Martin Resource Management to the employee of the right to purchase common units under the purchase plan. The right to purchase common units granted by the Company under the purchase plan is for the term of a purchase period.

During each purchase period, each participating employee may elect to make contributions to his bookkeeping account each pay period in an amount not less than one percent of his compensation and not more than fifteen percent of his compensation. The rate of contribution shall be designated by the employee at the time of enrollment. On each purchase date (the last day of such purchase period), units will be purchased for each participating employee at the fair market value of such units. The fair market value of the Units to be purchased during such purchase period shall mean the closing sales price of a unit on the purchase date.

Martin Resource Management Employee Stock Ownership Plans.

MRMC Employee Stock Ownership Plan. Martin Resource Management maintains an employee stock profit sharing plan that covers employees who satisfy certain minimum age and service requirements (“ESOP”). Under the terms of the ESOP, Martin Resource Management has the discretion to make contributions in an amount determined by its board of directors. Those contributions are allocated under the terms of the ESOP and invested primarily in the common stock of Martin Resource Management. Participants in the Martin ESOP become 100% vested upon completing six years of vesting service or upon their attainment of normal retirement age, permanent disability or death during employment. Any forfeitures of non-vested accounts may be used to pay administrative expenses and restore previous forfeitures of employees rehired before incurring five consecutive breaks-in-service. Any remaining forfeitures will be allocated to the accounts of employed participants. Participants are not permitted to make contributions including rollover contributions to the ESOP.

Martin Employees' Stock Profit Sharing Plan. Martin Resource Management maintains an employee profit sharing plan that covers employees who satisfied certain minimum age and service requirements but no Employee shall become eligible to participate in the Plan on or after January 1, 2013. This plan is referred to as the “Martin Employees' Stock Profit Sharing Plan". Under the terms of the plan, Martin Resource Management has the discretion to make contributions in an amount determined by its board of directors. Those contributions are allocated under the terms of the Martin Employees’ Stock Profit Sharing Plan and invested primarily in the common stock of Martin Resource Management. No contributions will be made to the Plan for any Plan Year commencing on or after January 1, 2013. The account balances of any participant who was employed by Martin Resource Management on December 31, 2012 shall be fully vested and non-forfeitable. This plan converted to an employee stock ownership plan on January 1, 2014.

Martin Resource Management 401(k) Profit Sharing Plan. Martin Resource Management maintains a profit sharing plan that covers employees who satisfy certain minimum age and service requirements. This profit sharing plan is referred to as the “401(k) Plan.” Eligible employees may elect to participate in the 401(k) Plan by electing pre-tax contributions up to 30% of their regular compensation and/or a portion of their discretionary bonuses. Matching contributions are made to the 401(k) Plan equal to 100% of the first 3% of eligible compensation, and 50% of the next 2% of eligible compensation. Martin Resource Management may make annual discretionary profit sharing contributions in an amount at the plan year end as determined by the board of directors of Martin Resource Management. Participants in the 401(k) Plan become 100% vested in matching contributions immediately and become vested in the discretionary contributions made for them upon completing five years of vesting service or upon their

attainment of age 65, permanent disability or death during employment.

Martin Resource Management Non-Qualified Option Plan. In September 1999, Martin Resource Management adopted a stock option plan designed to retain and attract qualified management personnel, directors and consultants. Under the plan, Martin Resource Management is authorized to issue to qualifying parties from time to time options to purchase up to 2,000 shares of its common stock with terms not to exceed ten years from the date of grant and at exercise prices generally not less than fair market value on the date of grant. In November 2007, Martin Resource Management adopted an additional stock option plan designed to retain and attract qualified management personnel, directors and consultants. In December 2013, all outstanding options were exercised or redeemed in lieu of redemption. There are no outstanding options under this plan as of December 31, 2013.

Other Compensation

Martin Resource Management generally does not pay for perquisites for any of our named executive officers other than general recreational activities at certain Martin Resource Management's properties located in Texas and use of Martin Resource Management vehicles, including aircraft.

SUMMARY COMPENSATION TABLE

The following table sets forth the compensation expense that was allocated to us for the services of the named executive officers for the years ended December 31, 2013, 2012 and 2011.

Name and Principal Position	Year	Salary (3)	Bonus	Stock Awards(2)	Total Compensation
Ruben S. Martin, President and Chief Executive Officer	2013	$375,000	$—	$310,600	$685,600
	2012	$283,593	$—	$—	$283,593
	2011	$124,371	$—	$—	$124,371
Robert D. Bondurant, Executive Vice President and Chief Financial Officer	2013	$200,000	$—	$62,120	$262,120
	2012	$151,307	$—	$—	$151,307
	2011	$125,761	$—	$—	$125,761
Randall L. Tauscher, Executive Vice President and Chief Operating Officer	2013	$268,000	$—	$62,120	$330,120
	2012	$224,502	$—	$—	$224,502
	2011	$210,548	$—	$—	$210,548
Wesley M. Skelton, Executive Vice President, Controller and Chief Administrative Officer	2013	$136,800	$—	$7,765	$144,595
	2012	$133,380	$—	$—	$133,380
	2011	$124,371	$—	$—	$124,371
Chris H. Booth, Executive Vice President, General Counsel and Secretary	2013	$102,000	$—	$62,120	$164,120
	2012	$94,755	$—	$—	$94,755
	2011	$88,814	$—	$—	$88,814

(1) Represents salary earned through date of resignation on October 31, 2012.
(2) The amounts shown represent the grant date fair value of awards computed in accordance with FASB ASC 718. See Note 17 included in Item 8 herein for the assumptions made in our valuation of such awards.
(3) Annual base salaries of the Named Executive Officers were not increased during 2013 by Martin Resource Management, although the allocated percentage of the Named Executive Officers annual base salaries increased.

Director Compensation

As a partnership, we are managed by our general partner. The board of directors of our general partner performs for us the functions of a board of directors of a business corporation. Directors of our general partner are entitled to receive total quarterly retainer fees of $16,250 each which are paid by the general partner. Martin Resource Management employees who are a member of the board of directors of our general partner do not receive any additional compensation for serving in such capacity. Officers of our general partner who also serve as directors will not receive additional compensation. All directors of our general partner are entitled to reimbursement for their reasonable out-of-pocket expenses in connection with their travel to and from, and attendance at, meetings of the board of directors or committees thereof. Each director will be fully indemnified by us for actions associated with being a director to the extent permitted under Delaware law.

The following table sets forth the compensation of our board members for the period from January 1, 2013 through December 31, 2013.

Name	Fees Earned Paid in Cash	Stock Awards	Total
Ruben S. Martin (1)	—	$310,600	$310,600
C. Scott Massey (2)	$57,500	$62,040	$119,540
Joe N. Averett, Jr. (2)	$57,500	$62,040	$119,540
Charles H. “Hank” Still (2)	$57,500	$62,040	$119,540
Byron R. Kelley (2)	$57,500	$62,040	$119,540

(1) On January 1, 2013, the Partnership issued 10,000 restricted common units to Ruben S. Martin, under our LTIP. These restricted common units vest in January 1, 2016. In calculating the fair value of the award, we multiplied the closing price of our common units on the NASDAQ on the date of grant, January 1, 2013, by the number of restricted common units granted to this director.

(2) On April 29, 2013, the Partnership issued 1,500 restricted common units to each of four independent directors, C. Scott Massey, Joe N. Averett, Jr., Byron R. Kelley, and Charles H. “Hank” Still, under our LTIP. These restricted common units vest in equal installments of 375 units on January 24, 2014, 2015, 2016 and 2017, respectively. In calculating the fair value of the award, we multiplied the closing price of our common units on the NASDAQ on the date of grant, April 29, 2013, by the number of restricted common units granted to each director.

COMPENSATION REPORT OF THE COMPENSATION COMMITTEE

The Compensation Committee of the general partner of Martin Midstream Partners L.P. has reviewed and discussed the Compensation Discussion and Analysis section of this report with management of the general partner of Martin Midstream Partners L.P. and, based on that review and discussions, has recommended that the Compensation Discussion and Analysis be included in this report.

Members of the Compensation Committee:
/s/ Byron R. Kelley
Byron R. Kelley, Committee Chair

/s/ Joe N. Averett, Jr.
Joe N. Averett Jr.

/s/ C. Scott Massey
C. Scott Massey

/s/ Charles H. Still
Charles H. Still

Compensation Committee Interlocks and Insider Participation

Other than these independent directors, no other officer or employee of our general partner or its subsidiaries is a member of the Compensation Committee. Employees of Martin Resource Management, through our general partner, are the individuals who work on our matters.

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Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The following table sets forth the beneficial ownership of our units as of March 3, 2014 held by beneficial owners of 5% or more of the units outstanding, by directors of our general partner, by each executive officer and by all directors and executive officers of our general partner as a group.

Name of Beneficial Owner(1)	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned(2)
MRMC ESOP Trust(3)	5,093,267	19.1%
Martin Resource Management Corporation(4)	5,093,267	19.1%
Martin Resource, LLC(4)	4,203,823	15.8%
Cross Oil Refining & Marketing Inc.(4)	889,444	3.3%
Ruben S. Martin(5)	5,168,522	19.4%
Robert D. Bondurant	18,848	—
Randall Tauscher	12,873	—
Wesley M. Skelton	6,945	—
Chris Booth	4,215	—
Alexander W.F. Black	—	—
Sean Dolan	—	—
C. Scott Massey(6)(7)	18,600	—
Joe N. Averett, Jr.(7)(8)	12,100	—
Charles H. Still(7)(8)	9,600	—
Byron R. Kelley(7)(8)	5,600	—
All directors and executive officers as a group (11 persons)(8)	5,257,303	19.7%

(1) The address for Martin Resource Management Corporation and all of the individuals listed in this table, unless otherwise indicated, is c/o Martin Midstream Partners L.P., 4200 Stone Road, Kilgore, Texas 75662.

(2) The percent of class shown is less than one percent unless otherwise noted.

(3) By virtue of its ownership of 81.4% of the outstanding common stock of Martin Resource Management Corporation (“Martin Resource Management”), the MRMC ESOP Trust (the “MRMC ESOP”) is the controlling shareholder of Martin Resource Management, and may be deemed to beneficially own the 5,093,267 MMLP Common Units held by Martin Resource LLC and Cross Oil Refining & Marketing Inc. Wilmington Trust Retirement and Institutional Services Company serves as trustee of the MRMC ESOP but all of its voting and investment decisions are directed by the board of directors of Martin Resource Management. The MRMC ESOP expressly disclaims beneficial ownership of the MMLP Common Units as voting and investment decisions are directed by the board of directors of Martin Resource Management.

(4) Martin Resource Management is the owner of Martin Resource, LLC and Cross Oil Refining & Marketing Inc., and as such may be deemed to beneficially own the common units held by Martin Resource LLC and Cross Oil Refining & Marketing Inc. The 4,203,823 common units beneficially owned by Martin Resource Management through its ownership of Martin Resource, LLC have been pledged as security to a third party to secure payment for a loan made by such third party. The 889,444 common units beneficially owned by Martin Resource Management through its ownership of Cross Oil Refining & Marketing Inc. have been pledged as security to a third party to secure payment for a loan made by such third party.

(5)

Includes 5,093,267 common units beneficially owned by Martin Resource Management through its ownership of Martin Resource, LLC and Cross Oil Refining & Marketing, Inc. Ruben S. Martin beneficially owns securities in Martin Resource Management representing approximately 19.4% of the voting stock thereof and serves as its Chairman of the Board and President. As a result, Ruben S. Martin may be deemed to be the beneficial owner of the common units and the subordinated units owned by Martin Resource Management. Ruben S. Martin has pledged 38,000 of his common units to third parties to secure payment for loans.

(6) Mr. Massey may be deemed to be the beneficial owner of 1,000 common units held by his wife.

(7) In February 2014, we issued 6,400 restricted common units to independent directors under our long-term incentive plan. These restricted common units vest in equal installments of 400 units on January 24, 2015, 2016, 2017 and 2018.

In April 2013, we issued 6,000 restricted common units to independent directors under our long-term incentive plan. These restricted common units vest in equal installments of 375 units on January 24, 2014, 2015, 2016 and 2017.

In January 2013, we issued 16,250 restricted common units to our five executive officer under our long-term incentive plan. These units vest will vest in January 2016.

On April 30, 2012, we issued 1,250 restricted common units to each of five independent directors under our long-term incentive plan. These restricted common units vest in equal installments of 312.5 units on January 24, 2013, 2014 2015, and 2016.

On May 2, 2011, we issued 1, 250 restricted common units to a independent advisory director. These units vest in 25% increments beginning in January 2012 and will be fully vested in January 2015.

On May 2, 2011, we issued 1,250 restricted common units to each of four independent directors. These units vest in 25% increments beginning in January 2012 and will be fully vested in January 2015.

(8) The total for all directors and executive officers as a group includes the common units directly owned by such directors and executive officers as well as the common units beneficially owned by Martin Resource Management as Ruben S. Martin may be deemed to be the beneficial owner thereof.

Martin Resource Management owns a 51% voting interest in the holding company that is the sole member of our general partner and, together with our general partner, owns approximately 19.1% of our outstanding common limited partner units as of March 3, 2014. The table below sets forth information as of March 3, 2014 concerning (i) each person owning beneficially in excess of 5% of common stock of Martin Resource Management, and (ii) the beneficial common stock ownership of (a) each director of Martin Resource Management, (b) each executive officer of Martin Resource Management, and (c) all such executive officers and directors of Martin Resource Management as a group. Except as indicated, each individual has sole voting and investment power over all shares listed opposite his or her name.

	Beneficial Ownership of Common Stock		
Name of Beneficial Owner(1)	Number of Shares	Percent of Outstanding	
MRMC ESOP Trust (2)	184,161.62	81.13	%
Martin ESOP Trust (3)	42,240.00	18.61	%
Wesley M. Skelton (3)	42,240.00	18.61	%

(1) The business address of each shareholder, director and executive officer of Martin Resource Management Corporation is c/o Martin Resource Management Corporation, 4200 Stone Road, Kilgore, Texas 75662.

(2) The MRMC ESOP owns 184,161.62 shares of common stock of Martin Resource Management. Wilmington Trust Retirement and Institutional Services Company serves as trustee of the MRMC ESOP but all of its voting and investment decisions related to the unallocated shares of common stock are directed by the board of directors of

Martin Resource Management. Of the common stock held by the MRMC ESOP, 56,119 shares of common stock are allocated to participant accounts, and 128,043 shares of common stock are unallocated.

(3) Wesley M. Skelton is a co-trustee of the Martin Employee Stock Ownership Trust which converted from a profit sharing plan known as the Martin Employees' Stock Profit Sharing Plan on January 1, 2014. Mr. Skelton exercises shared control over the voting and disposition of the securities owned by this trust. As a result, he may be deemed to be the beneficial owner of the securities held by such trust; thus, the number of shares of common stock reported herein as beneficially owned by him includes the 42,240 shares owned by such trust. Mr. Skelton disclaims beneficial ownership of these 42,240 shares.

The following table sets forth information regarding securities authorized for issuance under our equity compensation plans as of December 31, 2013:

Equity Compensation Plan Information

Plan Category	Number of securities to be issued upon exercise of outstanding options, Warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	N/A	N/A	N/A
Equity compensation plans not approved by security holders[1]	—	$—	620,900
Total	—	$—	620,900

[1]Our general partner has adopted and maintains the Martin Midstream Partners L.P. Long-Term Incentive Plan. For a description of the material features of this plan, please see "Item 11. Executive Compensation – Employee Benefit Plans – Martin Midstream Partners L.P. Long-Term Incentive Plan".

In October 2013, we issued 750 restricted common units to a certain Martin Resource Management employee under its long-term incentive plan. These units vest will vest in October 2016.

In April 2013, we issued 6,000 restricted common units to independent directors under our long-term incentive plan from purchased by us in the open market for $250. These restricted common units vest in equal installments of 375 units on January 24, 2014, 2015, 2016 and 2017, respectively.

In January 2013, we issued 57,750 restricted common units to certain Martin Resource Management employees under its long-term incentive plan. These units vest will vest in January 2016.

In April 2012, we issued 6,250 restricted common units to independent directors under our long-term incentive plan from purchased by us in the open market for $222. These restricted common units vest in equal installments of 312.5 units on January 24, 2013, 2014, 2015 and 2016, respectively.

In May 2011, we issued 6,250 restricted common units to independent directors under our long-term incentive plan from 5,750 treasury units purchased by us in the open market for $235 and 500 treasury units from forfeitures. These restricted common units vest in equal installments of 312.5 units on January 24, 2012, 2013, 2014 and 2015, respectively.

In February 2011, we issued 9,100 restricted common units to certain Martin Resource Management employees under its long-term incentive plan from 9,100 treasury units purchased by us in the open market for $347. These units vest in 25% increments beginning in February 2013 and will be fully vested in February 2015.

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Item 13. Certain Relationships and Related Transactions, and Director Independence

Martin Resource Management owns 5,093,267 of our common limited partnership units representing approximately 19.1% of our outstanding common limited partnership units as of March 3, 2014. Martin Resource Management controls Martin Midstream GP LLC, our general partner, by virtue of its 51% voting interest in MMGP Holdings, LLC, the sole member of our general partner. Our general partner owns a 2.0% general partner interest in us and all of our incentive distribution rights. Our general partner's ability to manage and operate us and Martin Resource Management's ownership of approximately 19.1% of our outstanding common limited partnership units effectively gives Martin Resource Management the ability to veto some of our actions and to control our management.

Distributions and Payments to the General Partner and its Affiliates

The following table summarizes the distributions and payments to be made by us to our general partner and its affiliates in connection with our formation, ongoing operation and liquidation. These distributions and payments were determined by and among affiliated entities and, consequently, are not the result of arm's-length negotiations.

Formation Stage	
The consideration received by our general partner and Martin Resource Management for the transfer of assets to us	4,253,362 subordinated units (All of the original 4,253,362 subordinated units issued to Martin Resource Management have been converted into common units on a one-for-one basis since the formation of the Partnership. 850,672 subordinated units were converted on each of November 14, 2005, 2006, 2007 and 2008, respectively, and 850,674 subordinated units were converted on November 14, 2009) 2% general partner interest; and the incentive distribution rights.
Operational Stage	
Distributions of available cash to our general partner	We will generally make cash distributions 98% to our unitholders, including Martin Resource Management as holder of all of the subordinated units, and 2% to our general partner. In addition, if distributions exceed the minimum quarterly distribution and other higher target levels, our general partner will be entitled to increasing percentages of the distributions, up to 50% of the distributions above the highest target level as a result of its incentive distribution rights. Assuming we have sufficient available cash to pay the full minimum quarterly distribution on all of our outstanding units for four quarters, our general partner would receive an annual aggregate distribution of approximately $1.8 million on its 2.0% general partner interest.
Payments to our general partner and its affiliates	Martin Resource Management is entitled to reimbursement for all direct expenses it or our general partner incurs on our behalf. The direct expenses include the salaries and benefit costs employees of Martin Resource Management who provide services to us. Our general partner has sole discretion in determining the amount of these expenses. In addition to the direct expenses, Martin Resource Management is entitled to reimbursement for a portion of indirect general and administrative and corporate overhead expenses. Under the omnibus agreement, we are required to reimburse Martin Resource Management for indirect general and administrative and corporate overhead expenses. The conflicts committee of our general partner ("Conflicts Committee") will review and approve future adjustments in the reimbursement amount for indirect expenses, if any, annually. Please read "Agreements — Omnibus Agreement" below.

Withdrawal or removal of our general partner	If our general partner withdraws or is removed, its general partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.
Liquidation Stage	
Liquidation	Upon our liquidation, the partners, including our general partner, will be entitled to receive liquidating distributions according to their particular capital account balances.

Agreements

Omnibus Agreement

We and our general partner are parties to an omnibus agreement with Martin Resource Management (the "Omnibus Agreement") that governs, among other things, potential competition and indemnification obligations among the parties to the

agreement, related party transactions, the provision of general administration and support services by Martin Resource Management and our use of certain of Martin Resource Management's trade names and trademarks. The Omnibus Agreement was amended on November 25, 2009, to include processing crude oil into finished products including naphthenic lubricants, distillates, asphalt and other intermediate cuts. The Omnibus Agreement was amended further on October 1, 2012, to permit the Partnership to provide certain lubricant packaging products and services to Martin Resource Management.

Non-Competition Provisions. Martin Resource Management agrees for so long as Martin Resource Management controls the general partner not to engage in the business of

- providing terminalling and storage services for petroleum products and by-products including the refining, blending and packaging of finished lubricants;
- providing marine transportation of petroleum products and by-products;
- distributing NGLs; and
- manufacturing and selling sulfur-based fertilizer products and other sulfur-related products.

This restriction does not apply to:

- the ownership and/or operation on our behalf of any asset or group of assets owned by us or our affiliates;

- any business operated by Martin Resource Management, including the following:

providing land transportation of various liquids,

distributing fuel oil, asphalt, sulfuric acid, marine fuel and other liquids,

providing marine bunkering and other shore-based marine services in Alabama, Louisiana, Mississippi and Texas,

operating a crude oil gathering business in Stephens, Arkansas,

providing crude oil gathering, refining, and marketing services of base oils, asphalt, and distillate products in Smackover, Arkansas,

operating an underground NGL storage facility in Arcadia, Louisiana,

operating an environmental consulting company,

operating an engineering services company,

supplying employees and services for the operation of the Partnership's business,

operating a natural gas optimization business,

operating, for its account and the Partnership's account, the docks, roads, loading and unloading facilities and other common use facilities or access routes at the Partnership's Stanolind terminal,

operating, solely for the Partnership's account, the asphalt facilities in Omaha, Nebraska, Port Neches, Texas and South Houston, Texas;

- any business that Martin Resource Management acquires or constructs that has a fair market value of less than $5.0 million;

- any business that Martin Resource Management acquires or constructs that has a fair market value of $5.0 million or more if we have been offered the opportunity to purchase the business for fair market value, and we decline to do so with the concurrence of our Conflicts Committee; and

- any business that Martin Resource Management acquires or constructs where a portion of such business includes a restricted business and the fair market value of the restricted business is $5.0 million or more and represents less than 20% of the aggregate value of the entire business to be acquired or constructed; provided that, following completion of the acquisition or construction, we are provided the opportunity to purchase the restricted business.

Services. Under the Omnibus Agreement, Martin Resource Management provides us with corporate staff and support services that are substantially identical in nature and quality to the services previously provided by Martin Resource Management in connection with its management and operation of our assets during the one-year period prior to the date of the agreement. The Omnibus Agreement requires us to reimburse Martin Resource Management for all direct expenses it incurs or payments it makes on our behalf or in connection with the operation of our business. There is no monetary limitation on the amount we are required to reimburse Martin Resource Management for direct expenses. In addition to the direct expenses, Martin Resource Management is entitled to reimbursement for a portion of indirect general and administrative and corporate overhead expenses.

Under the Omnibus Agreement, we are required to reimburse Martin Resource Management for indirect general and administrative and corporate overhead expenses. Effective January 1, 2014 through December 31, 2014, the Conflicts Committee approved an annual reimbursement for indirect expenses of $12.5 million. For the years ended December 31, 2013, 2012 and 2011, the Conflicts Committee approved and we reimbursed Martin Resource Management of $10.6 million, $7.6 million and $4.8 million, respectively, reflecting our allocable share of such expenses. The Conflicts Committee will review and approve future adjustments in the reimbursement amount for indirect expenses, if any, annually.

These indirect expenses cover all of the centralized corporate functions Martin Resource Management provides for us, such as accounting, treasury, clerical billing, information technology, administration of insurance, general office expenses and employee benefit plans and other general corporate overhead functions we share with Martin Resource Management retained businesses. The provisions of the Omnibus Agreement regarding Martin Resource Management's services will terminate if Martin Resource Management ceases to control our general partner.

Related Party Transactions. The Omnibus Agreement prohibits us from entering into any material agreement with Martin Resource Management without the prior approval of the Conflicts Committee. For purposes of the Omnibus Agreement, the term material agreements means any agreement between us and Martin Resource Management that requires aggregate annual payments in excess of then-applicable limitation on the reimbursable amount of indirect general and administrative expenses. Please read " Services" above.

License Provisions. Under the Omnibus Agreement, Martin Resource Management has granted us a nontransferable, nonexclusive, royalty-free right and license to use certain of its trade names and marks, as well as the trade names and marks used by some of its affiliates.

Amendment and Termination. The Omnibus Agreement may be amended by written agreement of the parties; provided, however that it may not be amended without the approval of the Conflicts Committee if such amendment would adversely affect the unitholders. The Omnibus Agreement was first amended on November 25, 2009, to permit us to provide refining services to Martin Resource Management. The Omnibus Agreement was amended further on October 1, 2012, to permit us to provide certain lubricant packaging products and services to Martin Resource Management. Such amendments were approved by the Conflicts Committee. The Omnibus Agreement, other than the indemnification provisions and the provisions limiting the amount for which we will reimburse Martin Resource Management for general and administrative services performed on our behalf, will terminate if we are no longer an affiliate of Martin Resource Management.

Motor Carrier Agreement

We are a party to a motor carrier agreement effective January 1, 2006, as amended, with Martin Transport, Inc., a wholly owned subsidiary of Martin Resource Management through which Martin Resource Management operates its land transportation operations. Under the agreement, Martin Transport, Inc. agrees to ship our NGL shipments as well as other liquid products.

Term and Pricing. The agreement has an initial term that expired in December 2007 but automatically renews for consecutive one-year periods unless either party terminates the agreement by giving written notice to the other party at least 30 days prior to the expiration of the then-applicable term. We have the right to terminate this agreement at anytime by providing 90 days prior notice. Under this agreement, Martin Transport, Inc. transports our NGL shipments as well as other liquid products. These rates are subject to any adjustment to which are mutually agreed or in accordance with a price

index. Additionally, during the term of the agreement, shipping charges are also subject to fuel surcharges determined on a weekly basis in accordance with the United States Department of Energy's national diesel price list.

Indemnification. Martin Transport has indemnified us against all claims arising out of the negligence or willful misconduct of Martin Transport and its officers, employees, agents, representatives and subcontractors. We indemnified Martin Transport against all claims arising out of the negligence or willful misconduct of us and our officers, employees, agents, representatives and subcontractors. In the event a claim is the result of the joint negligence or misconduct of Martin Transport and us, our indemnification obligations will be shared in proportion to each party's allocable share of such joint negligence or misconduct.

Terminal Services Agreements

Diesel Fuel Terminal Services Agreement. We are a party to an agreement under which we provide terminal services to Martin Resource Management. This agreement was amended and restated as of October 27, 2004 and was set to expire in December 2006, but automatically renewed and will continue to automatically renew on a month-to-month basis until either party terminates the agreement by giving 60 days written notice. The per gallon throughput fee we charge under this agreement may be adjusted annually based on a price index.

Miscellaneous Terminal Services Agreements. We are currently party to several terminal services agreements and, from time to time, we may enter into other terminal service agreements for the purpose of providing terminal services to related parties. Individually, each of these agreements is immaterial but when considered in the aggregate they could be deemed material. These agreements are throughput based with a minimum volume commitment. Generally, the fees due under these agreements are adjusted annually based on a price index.

Talen's Agreements. In connection with the Talen's acquisition, new agreements were executed, each with effective dates of December 31, 2012. Under the terms of these contracts, Talen's provides terminal services to Martin Resource Management. The terminal services agreements both have five-year terms and provide a per gallon throughput rate, which may be adjusted annually based on a price index.

Marine Agreements

Marine Transportation Agreement. We are a party to a marine transportation agreement effective January 1, 2006, which was amended January 1, 2007, under which we provide marine transportation services to Martin Resource Management on a spot-contract basis at applicable market rates. Effective each January 1, this agreement automatically renews for consecutive one-year periods unless either party terminates the agreement by giving written notice to the other party at least 60 days prior to the expiration of the then- applicable term. The fees we charge Martin Resource Management are based on applicable market rates.

Marine Fuel. We are a party to an agreement with Martin Resource Management dated November 1, 2002 under which Martin Resource Management provides us with marine fuel from its locations in the Gulf of Mexico at a fixed rate over the Platt's U.S. Gulf Coast Index for #2 Fuel Oil. Under this agreement, we agreed to purchase all of its marine fuel requirements that occur in the areas serviced by Martin Resource Management.

Other Agreements

Cross Tolling Agreement. We are party to an agreement with Cross, dated November 25, 2009, under which we process crude oil into finished products, including naphthenic lubricants, distillates, asphalt and other intermediate cuts for Cross. The tolling agreement, which has subsequently been amended, has a 22 year term which expires November 25, 2031. Under this tolling agreement, Martin Resource Management agreed to refine a minimum of

6,500 barrels per day of crude oil at the refinery at a fixed price per barrel. Any additional barrels are refined at a modified price per barrel. In addition, Martin Resource Management agreed to pay a monthly reservation fee and a periodic fuel surcharge fee based on certain parameters specified in the tolling agreement. All of these fees (other than the fuel surcharge) are subject to escalation annually based upon the greater of 3% or the increase in the Consumer Price Index for a specified annual period. In addition, every three years, the parties can negotiate an upward or downward adjustment in the fees subject to their mutual agreement.

Sulfuric Acid Sales Agency Agreement. We are a party to a second amended and restated sulfuric acid sales agency agreement dated August 5, 2013 under which Martin Resource Management purchases and markets the sulfuric acid produced by our sulfuric acid production plant at Plainview, Texas, and which is not consumed by our internal operations. This agreement, as amended, will remain in place until we terminate it by providing 180 days' written notice. Under this agreement,

we sell all of our excess sulfuric acid to Martin Resource Management. Martin Resource Management then markets such acid to third-parties and we share in the profit of Martin Resource Management's sales of the excess acid to such third parties.

Other Miscellaneous Agreements. From time to time we enter into other miscellaneous agreements with Martin Resource Management for the provision of other services or the purchase of other goods.

Other Related Party Transactions

2012 Public Offerings.

Public Offerings. On January 25, 2012, we completed a public offering of 2,645,000 common units at a price of $36.15 per common unit, before the payment of underwriters' discounts, commissions and offering expenses (per unit value is in dollars, not thousands). Total proceeds from the sale of the 2,645,000 common units, net of underwriters' discounts, commissions and offering expenses were $91.4 million. Our general partner contributed $2.0 million in cash to us in conjunction with the issuance in order to maintain its 2% general partner interest in us. On January 25, 2012, all of the net proceeds were used to reduce our outstanding indebtedness.

On November 26, 2012, we completed a public offering of 3,450,000 common units at a price of $31.16 per common unit, before the payment of underwriters' discounts, commissions and offering expenses (per unit value is in dollars, not thousands). Total proceeds from the sale of the 3,450,000 common units, net of underwriters' discounts, commissions and offering expenses were $102.8 million. Our general partner contributed $2.2 million in cash to us in conjunction with the issuance in order to maintain its 2% general partner interest in us. All of the net proceeds were used to reduce our outstanding indebtedness.

2011 Public Offering.

On February 9, 2011, we completed a public offering of 1,874,500 common units at a price of $39.35 per common unit, before the payment of underwriters' discounts, commissions and offering expenses (per unit value is in dollars, not thousands). Total proceeds from the sale of the 1,874,500 common units, net of underwriters' discounts, commissions and offering expenses were $70.7 million. Our general partner contributed $1.5 million in cash to us in conjunction with the issuance in order to maintain its 2% general partner interest in us.

Marine Transportation Equipment Purchase. On September 30, 2013, we acquired two inland tank barges from Martin Resource Management for $7.1 million. The excess carrying value of the assets over the purchase price paid by Martin Resource Management at the sales date was $0.3 million and was recorded as an adjustment to partners' capital.

Talen's Marine & Fuel, LLC. On December 31, 2012, we acquired all of the outstanding membership interests in Talen's from Quintana Energy Partners, L.P. for $103.4 million, subject to certain post-closing adjustments. Simultaneous with the acquisition, we sold certain working capital-related assets and a customer relationship intangible asset to Martin Energy Services LLC for $56.0 million. The excess carrying value of the assets over the purchase price paid by Martin Resource Management at the sales date was $4.3 million and was recorded as an adjustment to partners' capital.

Lubricant Product Blending and Packaging Assets. On October 2, 2012, we acquired from Cross, certain specialty lubricant product blending and packaging assets, including working capital, for total consideration of $121.8 million in cash at closing, plus a final net working capital adjustment of $0.9 million paid in October of 2012. This acquisition is considered a transfer of net assets between entities under common control. The acquisition of these blending and packaging assets was recorded at the historical carrying value of the assets at the acquisition date, which totaled $62.4

million. The excess purchase price over the historical carrying value of the assets at the acquisition date was $60.3 million and was recorded as an adjustment to partners' capital.

Redbird Class A Interests. On October 2, 2012, we acquired from Martin Resource Management all of the remaining Class A interests in Redbird for $150.0 million in cash. The acquisition of these interests was recorded at the historical carrying value of the interests at the acquisition date. We recorded an investment in consolidated entities of $68.2 million and the excess of the purchase price over the carrying value of the Class A interests of $81.8 million was recorded as an adjustment to partners' capital.

Acquisition of Certain Terminalling Assets. On January 31, 2011, we acquired 13 shore-based marine terminalling facilities, one specialty terminalling facility and certain terminalling related assets from Martin Resource Management for

$36.5 million. The net book value of the acquired assets of $16.8 million was recorded in property, plant and equipment. The remaining $19.7 million was recorded as a reduction of partners' capital.

Miscellaneous. Certain of directors, officers and employees of our general partner and Martin Resource Management maintain margin accounts with broker-dealers with respect to our common units held by such persons. Margin account transactions for such directors, officers and employees were conducted by such broker-dealers in the ordinary course of business.

For information regarding amounts of related party transactions that are included in the Partnership's Consolidated Statements of Operations, please see Footnote 13, "Related Party Transactions", in Part II, Item 8.

Approval and Review of Related Party Transactions

If we contemplate entering into a transaction, other than a routine or in the ordinary course of business transaction, in which a related person will have a direct or indirect material interest, the proposed transaction is submitted for consideration to the board of directors of our general partner or to our management, as appropriate. If the board of directors is involved in the approval process, it determines whether to refer the matter to the Conflicts Committee, as constituted under our limited partnership agreement. If a matter is referred to the Conflicts Committee, it obtains information regarding the proposed transaction from management and determines whether to engage independent legal counsel or an independent financial advisor to advise the members of the committee regarding the transaction. If the Conflicts Committee retains such counsel or financial advisor, it considers such advice and, in the case of a financial advisor, such advisor’s opinion as to whether the transaction is fair and reasonable to us and to our unitholders.

Item 14. Principal Accounting Fees and Services

KPMG, LLP served as our independent auditors for the fiscal years ended December 31, 2013 and 2012. The following fees were paid to KPMG, LLP for services rendered during our last two fiscal years:

	2013		2012	
Audit fees	$961,000	(1)	$1,302,000	(1)
Audit related fees	—		20,000	
Audit and audit related fees	961,000		1,322,000	
Tax fees	147,325	(2)	171,976	(2)
All other fees	—		—	
Total fees	$1,108,325		$1,493,976	

(1) 2013 audit fees include fees for the annual integrated audit and fees related to services in connection with filing updated financial statements and in connection with transactions. 2012 audit fees include fees for the annual integrated audit and fees related to services in connection with filing updated financial statements and in connection with transactions.

(2) Tax fees are for services related to the review of our partnership K-1's returns, and research and consultations on other tax related matters.

Under policies and procedures established by the Board of Directors and the Audit Committee, the Audit Committee is required to pre-approve all audit and non-audit services performed by our independent auditor to ensure that the provisions of such services do not impair the auditor’s independence. All of the services described above that were provided by KPMG LLP in years ended December 31, 2013 and December 31, 2012 were approved in advance by the Audit Committee.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) Financial Statements, Schedules

(1) The following financial statements of Martin Midstream Partners L.P. and are included in Part II, Item 8:

Reports of Independent Registered Public Accounting Firm
Consolidated Balance Sheets as of December 31, 2013 and 2012
Consolidated Statements of Operations for the years ended December 31, 2013, 2012 and 2011
Consolidated Statements of Comprehensive Income for the years ended December 31, 2013, 2012 and 2011
Consolidated Statements of Changes in Capital for the years ended December 31, 2013, 2012 and 2011
Consolidated Statements of Cash Flows for the years ended December 31, 2012, 2012 and 2011
Notes to the Consolidated Financial Statements

(2) Financial Statements of Waskom Gas Processing Company for the seven months ended July 31, 2012 and year ended December 31, 2011, an affiliate accounted for by the equity method, which constituted a significant subsidiary.

(b) Exhibits

Reference is made to the Index to Exhibits beginning on page 136 for a list of all exhibits filed as part of this report.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, we have duly caused this Report to be signed on our behalf by the undersigned, thereunto duly authorized representative.

Martin Midstream Partners L.P.
(Registrant)
By: Martin Midstream GP LLC
It's General Partner
Date: March 3, 2014 By: /s/ Ruben S. Martin
Ruben S. Martin
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on the 3rd day of March, 2014.

Signature	Title
/s/ Ruben S. Martin Ruben S. Martin	President, Chief Executive Officer and Director of Martin Midstream GP LLC (Principal Executive Officer)
/s/ Robert D. Bondurant Robert D. Bondurant	Executive Vice President and Chief Financial Officer of Martin Midstream GP LLC (Principal Financial Officer)
/s/ Wesley M. Skelton Wesley M. Skelton	Executive Vice President, Chief Administrative Officer, Secretary and Controller of Martin Midstream GP LLC (Principal Accounting Officer)
/s/ Alexander W.F. Black Alexander W.F. Black	Director of Martin Midstream GP LLC
/s/ Sean P. Dolan Sean P. Dolan	Director of Martin Midstream GP LLC
/s/ C. Scott Massey C. Scott Massey	Director of Martin Midstream GP LLC
/s/ Byron R. Kelley Byron R. Kelley	Director of Martin Midstream GP LLC
/s/ Joe N. Averett, Jr. Joe N. Averett, Jr.	Director of Martin Midstream GP LLC
/s/ Charles H. Still Charles H. Still	Director of Martin Midstream GP LLC

INDEX TO EXHIBITS

Exhibit Number	Exhibit Name
3.1	Certificate of Limited Partnership of Martin Midstream Partners L.P. (the "Partnership"), dated June 21, 2002 (filed as Exhibit 3.1 to the Partnership's Registration Statement on Form S-1 (SEC File No. 333-91706), filed July 1, 2002, and incorporated herein by reference).
3.2	Second Amended and Restated Agreement of Limited Partnership of the Partnership, dated as of November 25, 2009 (filed as Exhibit 10.1 to the Partnership's Amendment to Current Report on Form 8-K/A (SEC File No. 000-50056), filed January 19, 2010, and incorporated herein by reference).
3.3	Amendment No. 2 to the Second Amended and Restated Agreement of Limited Partnership of the Partnership, dated January 31, 2011 (filed as Exhibit 3.1 to the Partnership's Current Report on Form 8-K (SEC File No. 000-50056), filed February 1, 2011, and incorporated herein by reference).
3.4	Amendment No. 3 to the Second Amended and Restated Agreement of Limited Partnership of the Partnership, dated October 2, 2012 (filed as Exhibit 10.5 to the Partnership's Current Report on Form 8-K (SEC File No. 000-50056), filed October 9, 2012, and incorporated herein by reference).
3.5	Certificate of Limited Partnership of the Martin Operating Partnership L.P.(the "Operating Partnership"), dated June 21, 2002 (filed as Exhibit 3.3 to the Partnership's Registration Statement on Form S-1 (SEC File No. 333-91706), filed July 1, 2002, and incorporated herein by reference).
3.6	Amended and Restated Agreement of Limited Partnership of the Operating Partnership, dated November 6, 2002 (filed as Exhibit 3.2 to the Partnership's Current Report on Form 8-K (SEC File No. 000-50056), filed November 19, 2002, and incorporated herein by reference).
3.7	Certificate of Formation of Martin Midstream GP LLC (the "General Partner"), dated June 21, 2002 (filed as Exhibit 3.5 to the Partnership's Registration Statement on Form S-1 (SEC File No. 333-91706), filed July 1, 2002, and incorporated herein by reference).
3.8	Amended and Restated Limited Liability Company Agreement of the General Partner, dated August 30, 2013 (filed as Exhibit 3.1 to the Partnership's Current Report on Form 8-K (SEC File. No. 000-50056), filed September 3, 2013, and incorporated herein by reference.
3.9	Certificate of Formation of Martin Operating GP LLC (the "Operating General Partner"), dated June 21, 2002 (filed as Exhibit 3.7 to the Partnership's Registration Statement on Form S-1 (SEC File No. 333-91706), filed July 1, 2002, and incorporated herein by reference).
3.10	Limited Liability Company Agreement of the Operating General Partner, dated June 21, 2002 (filed as Exhibit 3.8 to the Partnership's Registration Statement on Form S-1 (SEC File No. 333-91706), filed July 1, 2002, and incorporated herein by reference).
4.1	Specimen Unit Certificate for Common Units (contained in Exhibit 3.2).
4.2	Specimen Unit Certificate for Subordinated Units (filed as Exhibit 4.2 to Amendment No. 4 to the Partnership's Registration Statement on Form S-1 (SEC File No. 333-91706), filed October 25, 2002, and incorporated herein by reference).
4.3	Indenture (including form of 8.875% Senior Note due 2018), dated as of March 26, 2010, by and among the Partnership, Martin Midstream Finance Corp., the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.1 to the Partnership's Current Report on Form 8-K (SEC File No. 000-50056), filed March 26, 2010, and incorporated herein by reference).
4.4	First Supplemental Indenture, to the Indenture dated as of March 26, 2010, dated as of February 11, 2013, by and among the Partnership, Martin Midstream Finance Corp., the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.4 to the Partnership's Annual Report on Form 10-K (SEC File No. 000-50056), filed March 4, 2013, and incorporated herein by reference).
4.5	Indenture (including form of 7.250% Senior Notes due 2021), dated as of February 11, 2013, by and among the Partnership, Martin Midstream Finance Corp., the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.1 to the Partnership's Current Report on Form 8-K (SEC

	File No. 000-50056), filed February 12, 2013, and incorporated herein by reference).
10.1	Third Amended and Restated Credit Agreement, dated March 28, 2013, among the Partnership, the Operating Partnership, Royal Bank of Canada and the other Lenders set forth therein (filed as Exhibit 10.1 to the Partnership's Current Report on Form 8-K (SEC File No. 000-50056), filed April 3, 2013 and incorporated herein by reference).
10.2	Omnibus Agreement, dated November 1, 2002, by and among Martin Resource Management Corporation, the General Partner, the Partnership and the Operating Partnership (filed as Exhibit 10.3 to the Partnership's Current Report on Form 8-K (SEC File No. 000-50056), filed November 19, 2002, and incorporated herein by reference).

10.3	Amendment No. 1 to Omnibus Agreement, dated as of November 25, 2009, by and among Martin Resource Management Corporation, the General Partner, the Partnership and the Operating Partnership (filed as Exhibit 10.3 to the Partnership's Current Report on Form 8-K (SEC File No. 000-50056), filed December 1, 2009, and incorporated herein by reference).
10.4	Amendment No. 2 to Omnibus Agreement, dated October 1, 2012, by Martin Resource Management Corporation, the General Partner, the Partnership and the Operating Partnership (filed as Exhibit 10.4 to the Partnership's Current Report on Form 8-K (SEC File No. 000-50056), filed October 9, 2012, and incorporated herein by reference).
10.5	Motor Carrier Agreement, dated January 1, 2006, by and between the Operating Partnership and Martin Transport, Inc. (filed as Exhibit 10.9 to the Partnership's Annual Report on Form 10-K (SEC File No. 000-50056), filed March 2, 2011, and incorporated herein by reference).
10.6	Marine Transportation Agreement, dated January 1, 2006, by and between the Operating Partnership and Midstream Fuel Service, L.L.C. (filed as Exhibit 10.10 to the Partnership's Annual Report on Form 10-K (SEC File No. 000-50056), filed March 2, 2011, and incorporated herein by reference).
10.7	Product Storage Agreement, dated November 1, 2002, by and between Martin Underground Storage, Inc. and the Operating Partnership (filed as Exhibit 10.8 to the Partnership's Current Report on Form 8-K (SEC File No. 000-50056), filed November 19, 2002, and incorporated herein by reference).
10.8	Marine Fuel Agreement, dated November 1, 2002, by and between Martin Fuel Service LLC and the Operating Partnership (filed as Exhibit 10.9 to the Partnership's Current Report on Form 8-K (SEC No. 000-50056), filed November 19, 2002, and incorporated herein by reference).
10.9†	Martin Midstream Partners L.P. Amended and Restated Long-Term Incentive Plan (filed as Exhibit 10.1 to the Partnership's Current Report on Form 8-K (SEC No. 000-50056), filed January 26, 2006, and incorporated herein by reference).
10.10†	Form of Restricted Common Unit Grant Notice (filed as Exhibit 10.2 to the Partnership's Current Report on Form 8-K (SEC No. 000-50056), filed January 26, 2006, and incorporated herein by reference).
10.11	Purchaser Use Easement, Ingress-Egress Easement, and Utility Facilities Easement dated November 1, 2002, by and between MGSLLC and the Operating Partnership (filed as Exhibit 10.13 to the Partnership's Current Report on Form 8-K/A (SEC No. 000-50056), filed November 19, 2002, and incorporated herein by reference).
10.12	Asset Purchase Agreement by and among the Partnership, the Operating Partnership and Tesoro Marine Services, L.L.C., dated October 27, 2003 (filed as Exhibit 10.1 to the Partnership's Amendment No. 1 to Current Report on Form 8-K/A (SEC No. 000-50056), filed January 23, 2004, and incorporated herein by reference).
10.13	Purchase Agreement by and among the Operating Partnership, Prism Gas Systems I, L.P., Natural Gas Partners V, L.P., Robert E. Dunn, William J. Diehnelt, Gene A. Adams, Philip D. Gettig, Sharon L. Taylor and Scott A. Southard, dated September 6, 2005 (filed as Exhibit 10.1 to the Partnership's Current Report on Form 8-K (SEC No. 000-50056), filed September 6, 2005, and incorporated herein by reference).
10.14	Amended and Restated Terminal Services Agreement by and between the Operating Partnership and Martin Fuel Service LLC ("MFSLLC"), dated October 27, 2004 (filed as Exhibit 10.1 to the Partnership's Current Report on Form 8-K (SEC No. 000-50056), filed October 28, 2004, and incorporated herein by reference).
10.15	Lubricants and Drilling Fluids Terminal Services Agreement by and between the Operating Partnership and MFSLLC, dated December 23, 2003 (filed as Exhibit 10.4 to the Partnership's Amendment No. 1 to Current Report on Form 8-K/A (SEC No. 000-50056), filed January 23, 2004, and incorporated herein by reference).
10.16(1)	Second Amended and Restated Sales Agency Agreement, dated August 5, 2013, by and between the Operating Partnership and Martin Product Sales LLC (filed as Exhibit 10.2 to the Partnership's Quarterly Report on Form 10-Q (SEC No. 000-50056) filed November 4, 2013).
10.17†	Martin Resource Management Corporation Purchase Plan for Units of the Partnership, effective July 1, 2006, (filed as Exhibit 10.1 to the Partnership's registration statement on Form S-8 (SEC File No.

	333-140152), filed January 23, 2007, and incorporated herein by reference).
10.18	Form of Partnership Indemnification Agreement (filed as Exhibit 10.1 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 000-50056), filed November 6, 2008, and incorporated herein by reference).
10.19	Tolling Agreement, dated as of November 25, 2009, by and between the Operating Partnership and Cross Oil Refining & Marketing, Inc. (filed as Exhibit 10.2 to the Partnership's Current Report on Form 8-K (SEC File No. 000-50056), filed December 1, 2009, and incorporated herein by reference).
10.20	Amended and Restated Common Unit Purchase Agreement, dated as of November 24, 2009, by and between the Partnership and Martin Resource Management (filed as Exhibit 10.4 to the Partnership's Current Report on Form 8-K (SEC File No. 000-50056), filed December 1, 2009, and incorporated herein by reference).
10.21	Second Amended and Restated LLC Agreement of Redbird Gas Storage LLC, dated as of October 2, 2012. (filed as Exhibit 10.6 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 000-50056), filed November 5, 2012, and incorporated herein by reference).

10.22	Supply Agreement dated, as of October 2, 2012, by and between the Partnership and Cross Oil & Refining Marketing Inc. (filed as Exhibit 10.7 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 000-50056), filed November 5, 2012, and incorporated herein by reference).
10.23	Noncompetition Agreement dated, as of October 2, 2012, by and among the Partnership, Cross Oil Refining & Marketing, Inc., and Martin Resource Management Corporation (filed as Exhibit 10.8 to the Partnership's Quarterly Report on Form 10-Q (SEC File No. 000-50056), filed November 5, 2012, and incorporated herein by reference).
10.24	Purchase Price Reimbursement Agreement, dated October 2, 2012, by Martin Resource Management Corporation to and for the benefit of the Operating Partnership (filed as Exhibit 10.2 to the Partnership's Current Report on Form 8-K (SEC File No. 000-50056), filed October 9, 2012, and incorporated herein by reference).
21.1*	List of Subsidiaries.
23.1*	Consent of KPMG LLP.
23.2*	Consent of KPMG LLP.
31.1*	Certifications of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certifications of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Chief Executive Officer pursuant to 18 U.S.C., Section 1350, as adopted pursuant to Section 9.06 of the Sarbanes-Oxley Act of 2002. Pursuant to SEC Release 34-47551, this Exhibit is furnished to the SEC and shall not be deemed to be "filed."
32.2*	Certification of Chief Financial Officer pursuant to 18 U.S.C., Section 1350, as adopted pursuant to Section 9.06 of the Sarbanes-Oxley Act of 2002. Pursuant to SEC Release 34-47551, this Exhibit is furnished to the SEC and shall not be deemed to be "filed."
101	Interactive Data: the following financial information from Martin Midstream Partners L.P.'s Annual Report on Form 10-K for the fiscal year ended December 31, 2012, formatted in Extensible Business Reporting Language: (1) the Consolidated Balance Sheets; (2) the Consolidated Statements of Income; (3) the Consolidated Statements of Cash Flows; (4) the Consolidated Statements of Capital; (5) the Consolidated Statements of Other Comprehensive Income; and (6) the Notes to Consolidated Financial Statements, tagged as blocks of text.
*	Filed or furnished herewith.
†	As required by Item 15(a)(3) of Form 10-K, this exhibit is identified as a compensatory plan or arrangement.

(1) Material has been redacted from this exhibit and filed separately with the Commission pursuant to a request for confidential treatment pursuant to Rule 24b-2 of the Securities Exchange Act of 1934, as amended, which has been granted.

Financial Statement Schedule
Pursuant to Item 15(a)(2)

Waskom Gas Processing Company
Consolidated Financial Statements July 31, 2012 (unaudited) and December 31, 2011 and for the seven months ended July 31, 2012 (unaudited) and the year ended December 31, 2011 (with Independent Auditors' Report thereon).

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INDEPENDENT AUDITORS' REPORT

To the Partners of
Waskom Gas Processing Company:

We have audited the accompanying consolidated balance sheet of Waskom Gas Processing Company and subsidiaries (the “Partnership”) as of December 31, 2011 and the related consolidated statements of income, partners' capital, and cash flows for the year ended December 31, 2011. These consolidated financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

We conducted our audit in accordance with auditing standards generally accepted in the United States of America. 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 also includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Waskom Gas Processing Company and subsidiaries as of December 31, 2011 and the results of their operations and their cash flows for the year ended December 31, 2011, in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP
Shreveport, Louisiana March 5, 2012

WASKOM GAS PROCESSING COMPANY

CONSOLIDATED BALANCE SHEETS
AS OF JULY 31, 2012 AND DECEMBER 31, 2011

	2012 (Unaudited)	2011
ASSETS		
CURRENT ASSETS:		
Cash	$2,191,147	$757,494
Accounts receivable	1,172,173	1,473,935
Accounts receivable - partners	5,869,715	18,241,163
Inventories	574,652	423,474
Prepaid expenses	—	26,224
Total current assets	9,807,687	20,922,290
PROPERTY AND EQUIPMENT:		
Gas plant asset and gas gathering equipment	164,365,426	157,072,005
Other fixed assets	746,743	746,743
Accumulated depreciation and amortization	(36,997,090)	(32,336,265)
Net property and equipment	128,115,079	125,482,483
NON-CURRENT ASSETS:		
Other non-current assets:	133,500	250,000
TOTAL	$138,056,266	$146,654,773
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable and accrued liabilities	$5,882,893	$14,934,725
Accounts payable - partners	2,131,007	4,057,864
Total current liabilities	8,013,900	18,992,589
LONG-TERM LIABILITIES - Asset retirement obligation	833,590	799,527
COMMITMENTS AND CONTINGENCIES		
PARTNERS' CAPITAL	129,208,776	126,862,657
TOTAL	$138,056,266	$146,654,773

See accompanying notes to consolidated financial statements.

WASKOM GAS PROCESSING COMPANY
CONSOLIDATED STATEMENTS OF INCOME
FOR THE SEVEN MONTHS ENDED JULY 31, 2012 AND
YEAR ENDED DECEMBER 31, 2011

	2012 (Unaudited)	2011
OPERATING REVENUES:		
Natural gas processing and other revenues	$22,401,200	$39,618,717
Natural gas liquid sales	44,261,039	88,654,517
Gain/loss on disposal of assets	(83,205)	845,567
Total operating revenues	66,579,034	129,118,801
OPERATING COSTS AND EXPENSES:		
Cost of sales - natural gas liquids	46,502,430	92,705,171
Operating costs	6,296,194	10,126,797
Depreciation and amortization	4,694,888	6,849,262
Total operating costs and expenses	57,493,512	109,681,230
OPERATING INCOME INCOME BEFORE TAXES	9,085,522	19,437,571
Income tax expense	100,000	53,008
NET INCOME	$8,985,522	$19,384,563

See accompanying notes to consolidated financial statements.

WASKOM GAS PROCESSING COMPANY
CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
FOR THE SEVEN MONTHS ENDED JULY 31, 2012 AND YEAR ENDED DECEMBER 31, 2011

	Total Partners' Capital
BALANCE - December 31, 2010	$107,508,444
Cash contributions for capital expenditures	32,209,322
Cash distributions in excess of working capital	(4,432,461)
Cash distributions	(2,400,000)
Distributions in-kind	(25,407,211)
Net Income	19,384,563
BALANCE - December 31, 2011	126,862,657
Cash contributions for capital expenditures (unaudited)	7,293,499
Cash distributions in excess of working capital (unaudited)	(1,209,056)
Distributions in-kind (unaudited)	(12,723,846)
Net Income (unaudited)	8,985,522
BALANCE - July 31, 2012 (Unaudited)	$129,208,776

See accompanying notes to consolidated financial statements.

WASKOM GAS PROCESSING COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE SEVEN MONTHS ENDED JULY 31, 2012 AND
YEAR ENDED DECEMBER 31, 2011

	2012 (Unaudited)	2011
OPERATING ACTIVITIES:		
Net Income	$8,985,522	$19,384,563
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	4,694,888	6,849,262
Distributions in-kind to partners	(12,723,846)	(25,407,211)
Loss / (Gain) on sale of asset	83,205	(845,567)
Changes in operating assets and liabilities:		
Accounts receivable	301,762	(527,729)
Accounts receivable - partners	12,371,448	(7,533,187)
Inventory	(151,178)	79,975
Prepaid expenses	26,224	(2,160)
Other non-current assets, net	116,500	—
Accounts payable and accrued liabilities	(9,086,227)	6,330,191
Accounts payable - partners	(1,926,857)	(920,761)
Net cash provided by (used in) operating activities	2,691,441	(2,592,624)
INVESTING ACTIVITIES:		
Additions to property and equipment	(7,375,526)	(25,489,809)
Acquisitions, net of cash required	—	—
Proceeds from sale / disposal of assets	33,295	2,502,000
Net cash used in investing activities	(7,342,231)	(22,987,809)
FINANCING ACTIVITIES:		
Contributions from partners	7,293,499	32,209,322
Distributions to partners	(1,209,056)	(6,832,462)
Net cash provided by financial activities	6,084,443	25,376,860
NET INCREASE (DECREASE) IN CASH	1,433,653	(203,573)
CASH - Beginning of year	757,494	961,067
CASH - End of year	$2,191,147	$757,494
SUPPLEMENTAL CASH FLOWS DISCLOSURES:		
Taxes paid	$97,342	$196,544

See accompanying notes to consolidated financial statements.

WASKOM GAS PROCESSING COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. NATURE OF BUSINESS

Waskom Gas Processing Company (the “Partnership”), a Texas General Partnership, was formed on November 1, 1995 to construct and operate the Waskom Processing Plant (“the Plant”). As of December 31, 2011 the partners are CenterPoint Energy Gas Processing Company (50%) and Prism Gas Systems I, L.P. (50%). Prism Gas Systems I, L.P. serves as operator. The Partnership is engaged in the processing, gathering and marketing of natural gas and natural gas liquids (“NGL's”), predominantly in Texas and northwest Louisiana.

The Plant is a 320 MMcfd cryogenic turboexpander gas plant located in Harrison County, Texas. The Plant has full NGL fractionation, treating and stabilization capabilities. Fractionation is a process used to separate the mixture of NGL's into individual products for sale. Expansions to the processing plant were completed in March and June of 2007, July of 2008, June of 2009 and September of 2011 increasing the capacity from 150 MMcfd to 320 MMcfd. In July 2009 the Waskom fractionator was expanded to a capacity of 14,500 barrels per day from 12,500 barrels per day. A NGL railroad loading facility was constructed in 2011 and was placed in operation in the first quarter of 2012.

The natural gas supply for the Plant is derived primarily from natural gas wells located in the Cotton Valley formation of East Texas and Northwest Louisiana. The primary suppliers of natural gas to the Plant include BP American Production Company, Centerpoint Energy Gas Transmission Company, Samson Lone Star, LLC and Devon Energy Corporation, which collectively represent approximately 75% of the 252 MMcfd of natural gas supplied for the seven months ended July 31, 2012. The primary suppliers of natural gas to the Plant include BP American Production Company, Centerpoint Energy Gas Transmission Company, GMX/Endeavour Pipeline, Inc., Samson Lone Star, LLC and Devon Energy Corporation, which collectively represent approximately 77% of the 269 MMcfd of natural gas supplied for the year ended December 31, 2011.

The processing contracts for the Waskom Processing Plant are primarily percent-of-liquids (“POL”) contracts, in which we retain a portion of the NGL's recovered as a processing fee, percent-of-proceeds (“POP”) contracts in which we retain a portion of both the residue gas and the NGL's as payment for services and straight fee contracts in which we receive a fee for every Mcf of gas delivered to the plant. As of July 31, 2012, approximately 37.5% of the contracts are POL, 25% of the contracts are fee and 25% of the contracts are POP (unaudited). In addition, there is one minor contract for processing on a keep-whole basis and there is one purchase contract.

Sales of third party gas and fractionated NGL's are predominately to the partners and occur at the tailgate of the Plant.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation - During 2010 and 2008, Waskom Midstream LLC and Waskom Products Pipeline, LLC, respectively, were formed as wholly owned subsidiaries of Waskom Gas Processing Company, to hold certain plant and pipeline assets of the Partnership. Accordingly, the financial statements are consolidated to include these entities. All eliminations of intercompany balances have been made.

Accounts Receivable - Accounts receivable include trade receivables, recorded at invoiced amounts.

Property and Equipment - Property and equipment are stated at cost and depreciated using the straight-line method over the estimated useful lives of the classes of assets, as follows:

Depreciation expense was $4,660,825 (unaudited) and $6,794,726 for the seven months ended 2012 and the year ended December 31, 2011, respectively. Repairs and maintenance are charged to operations as incurred. Renewals and

betterments are capitalized.

Inventories - Substantially all inventory at July 31, 2012 and December 31, 2011 represents pipe held for future projects. Such pipe was valued at acquisition cost.

Asset Retirement Obligations - The Partnership records asset retirement obligations (“ARO”) for costs associated with legal obligations to retire tangible, long-lived assets. The Partnership records as an offset to the “ARO”, an asset at fair

value in the period in which it is incurred by increasing the carrying amount of the related long-lived asset. In each subsequent period, the liability is accreted over time towards the ultimate obligation amount and the capitalized costs are depreciated over the useful life of the related asset. The Partnership's asset retirement obligations include purging, plugging and remediation costs associated with the pipeline. Accretion expense for the seven months ended July 31, 2012, and the year ended December 31, 2011 was $34,063 (unaudited) and $54,536, respectively.

Impairment of Long-Lived Assets - Long-lived assets, such as property, plant and equipment, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated future cash flows, an impairment charge is recognized by the amount by which the carrying amount of the asset exceeds the fair value of the asset.

Revenue Recognition - Revenues are recognized when title passes or service is performed. The Partnership's business consists largely of the ownership and operation of physical assets. End sales from these businesses result in physical deliveries of commodities.

Federal Income Taxes - The Partnership is a Texas General Partnership and as such has no liability for Federal Income Taxes. Each partner is responsible for its share of federal income tax.

On May 18, 2006, the Texas Governor signed into law a Texas margin tax (H.B. No. 3) which restructures the state business tax by replacing the taxable capital and earned surplus components of the then existing franchise tax with a new “taxable margin” component. Since the tax base on the Texas margin tax is derived from an income-based measure, the margin tax is construed as an income tax and, therefore, the recognition of deferred taxes applies to the new margin tax. These deferred taxes are immaterial. Texas margin tax expense for the seven months ended July 31, 2012 and the year ended December 31, 2012 and 2011 was $100,000 (unaudited) and $53,008, respectively.

Environmental Liabilities - The Partnership's policy is to accrue for losses associated with environmental remediation obligations when such losses are probable and reasonably estimable. Accruals for estimated losses for environmental remediation obligations generally are recognized no later than completion of the remedial feasibility study. Such accruals are adjusted as further information develops or circumstances change. Costs of future expenditures for environmental remediation obligations are not discounted to their present value.

Use of Estimates - The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts at the date of the financial statements and the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities, revenues and expenses during the reporting period. Actual results could differ from those estimates.

3. RELATED-PARTY TRANSACTIONS

During 2012 and 2011, the Partnership engaged in certain material transactions with the partners. The Partnership believes that the terms of these transactions were comparable to those that could have been negotiated with unrelated third parties. As of July 31, 2012 and December 31, 2011, the Partnership had receivables of approximately $5,869,715 (unaudited) and $18,241,163, respectively, and payables of approximately $2,131,007 (unaudited) and $4,057,864, respectively, due from and due to the partners.

Per the partnership agreement, cash contributions are made by the partners for capital expenditures and working capital. Contributions for capital expenditures totaled $7,293,499 (unaudited) and $32,209,322 for the seven months ended 2012, and the year ended 2011, respectively. The partnership agreement allows for cash distributions to be made to the partners of any cash available in excess of working capital requirements, generally equal to two months of

historical operating expenses. Such cash distributions in excess of working capital totaled $1,209,056 (unaudited) and $4,432,461 for the seven months ended 2012, and the year ended 2011, respectively. Other cash distributions totaled $0 (unaudited) and$2,400,000 for the seven months ended 2012, and the year ended 2011, respectively.

The Partnership purchases gas from third party producers and processes this gas based on processing contracts, which are primarily POL contracts. The percentage of liquids retained by the Partnership is distributed to the partners as distributions of products-in-kind based on the partners' equity interest. Distributions of products in-kind of $12,723,846 (unaudited) and

$25,407,211for the seven months ended 2012, and the year ended 2011, respectively, were made to the partners. Distributions of products in-kind are valued at prevailing market prices at the time of distribution.
In some instances, the fractionated NGL's (less any retained portions) are returned to the third party producers, but in most cases, the third party producers enter into agreements with the partners to market their product. In such instances, the Partnership will sell the product to the partners. Such sales amounted to $48,098,581 (unaudited) and $85,613,194 for the seven months ended 2012, and the year ended 2011, respectively, and are included as natural gas liquid sales in the income statement.

4. ACQUISITION
On January 15, 2010, the Partnership through its wholly owned subsidiary Waskom Midstream LLC, acquired from Crosstex North Texas Gathering, L.P., a 100% interest in approximately 62 miles of gathering pipeline, two 35 MMcfd dew point control plants and equipment referred to as the Harrison Pipeline System for approximately $40,000,000.

5. COMMITMENTS AND CONTINGENCIES
The Partnership is subject to extensive federal, state and local environmental laws and regulations. These laws, which are constantly changing, regulate the discharge of materials into the environment and may require the Partnership to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a noncapital nature are recorded when environmental assessment and/or remediation is probable, and the costs can be reasonably estimated. Management believes that any future costs should not have a material adverse effect on the Partnership's liquidity or financial position.

6. SUBSEQUENT EVENT
On July 31, 2012, Prism Gas Systems I, L.P. sold its 50% interest in the Partnership to CenterPoint Energy Gas Processing Company.