Blueknight Energy Partners, L.P.
Form 10-K
March 14, 2013

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

FORM 10-K

ý Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2012

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 001-33503

BLUEKNIGHT ENERGY PARTNERS, L.P.
(Exact name of registrant as specified in its charter)

| | |
|---|---|
| Delaware | 20-8536826 |
| (State or other jurisdiction of incorporation or organization) | (IRS Employer Identification No.) |

201 NW 10th, Suite 200
Oklahoma City, Oklahoma 73103
(Address of principal executive offices, zip code)

Registrant’s telephone number, including area code: (405) 278-6400

(Former name, former address and former fiscal year, if changed since last report)

Securities Registered Pursuant to Section 12(b) of the Act:

| Title of each class | Name of each exchange on which registered |
|---|---|
| Common Units representing limited partner interests | Nasdaq Global Market |
| Series A Preferred Units representing limited partner interests | Nasdaq Global Market |

Securities Registered Pursuant to Section 12(g) of the Act:

None

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

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 x

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes 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 (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

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

| | |
|---|---|
| Large accelerated filer o | Accelerated filer ý |
| 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, 2012, the aggregate market value of the registrant’s common units held by non-affiliates of the registrant was approximately $53.6 million, based on $6.66 per common unit, the closing price of the common units as reported on the NASDAQ Global Market on such date.

As of March 7, 2013, there were 30,159,958 Series A Preferred Units and 22,675,135 common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:
None.

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DEFINITIONS

We use the following terms in this report:

Barrel: One barrel of petroleum products equals 42 United States gallons.

Bpd: Barrels per day.

Common carrier pipeline: A pipeline engaged in the transportation of petroleum products as a public utility and common carrier for hire.

Condensate: A natural gas liquid with a low vapor pressure, mainly composed of propane, butane, pentane and heavier hydrocarbon fractions.

Feedstock: A raw material required for an industrial process such as in petrochemical manufacturing.

Finished asphalt products: As used herein, the term refers to liquid asphalt cement sold directly to end users and to asphalt emulsions, asphalt cutbacks, polymer modified asphalt cement and related asphalt products processed using liquid asphalt cement. The term is also used to refer to various residual fuel oil products directly sold to end users.

Liquid asphalt cement: Liquid asphalt cement is a dark brown to black cementitious material that is primarily produced by petroleum distillation. When crude oil is separated in distillation towers at a refinery, the heaviest hydrocarbons with the highest boiling points settle at the bottom. These tar-like fractions, called residuum, require relatively little additional processing to become products such as asphalt cement or residual fuel oil. Liquid asphalt cement is primarily used in the road construction and maintenance industry. Residual fuel oil is primarily used as a burner fuel in numerous industrial and commercial business applications. As used herein, the term refers to both liquid asphalt cement and residual fuel oils.

Midstream: The industry term for the components of the energy industry in between the production of oil and gas (upstream) and the distribution of refined and finished products (downstream).

PMAC: Polymer modified asphalt cement.

Preferred Units: Series A Preferred Units represents limited partnership interests in our partnership.

SemCorp: SemCorp refers to SemGroup Corporation and its predecessors (including SemGroup, L.P.), subsidiaries and affiliates (other than our General Partner and us during periods in which we were affiliated with SemGroup, L.P.).  SemCorp and certain of its subsidiaries filed voluntary petitions for reorganization under Chapter 11 of the Bankruptcy Code in the United States Bankruptcy Court for the District of Delaware, Case No. 08-11547-BLS.  We were not a party to SemCorp’s bankruptcy filings.

Terminalling: The receipt of crude oil and petroleum products for storage into storage tanks and other appurtenant equipment, including pipelines, where the crude oil and petroleum products will be commingled with other products of similar quality; the storage of the crude oil and petroleum products; and the delivery of the crude oil and petroleum products as directed by a distributor into a truck, vessel or pipeline.

Throughput: The volume of product transported or passing through a pipeline, plant, terminal or other facility.

# PART I.

As used in this annual report, unless we indicate otherwise: (1) "Blueknight Energy Partners," "our," "we," "us" and similar terms refer to Blueknight Energy Partners, L.P. , together with its subsidiaries, (2) our "General Partner" refers to Blueknight Energy Partners G.P., L.L.C. , (3) "Vitol" refers to Vitol Holding B.V., its affiliates and subsidiaries (other than our General Partner and us) and (4) "Charlesbank" refers to Charlesbank Capital Partners, LLC, its affiliates and subsidiaries (other than our General Partner and us).

## Forward Looking Statements

This report contains "forward-looking statements" within the meaning of the federal securities laws. Statements included in this annual report that are not historical facts (including any statements regarding 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 "may," "will," "should," "believe," "expect," "intend," "anticipate," "estimate," "continue" or other similar words. These stater discuss 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.

Such forward-looking statements are subject to various risks and uncertainties that could cause actual results to differ materially from those anticipated as of the date of this report. Although we believe that the expectations reflected in these forward-looking statements are based on reasonable assumptions, no assurance can be given that these expectations will prove to be correct. Important factors that could cause our actual results to differ materially from the expectations reflected in these forward-looking statements include, among other things, those set forth in "Item 1A-Risk Factors," included in this annual report, and those set forth from time to time in our filings with the Securities and Exchange Commission ("SEC"), which are available through the Investor Relations link at www.bkep.com and through the SEC's Electronic Data Gathering and Retrieval System ("EDGAR") at http://www.sec.gov.

All forward-looking statements included in this report are based on information available to us on the date of this report. We undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events or otherwise. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements contained throughout this report.

## Item 1. Business

### Overview

We are a publicly traded master limited partnership with operations in twenty-three states. We provide integrated terminalling, storage, processing, gathering and transportation services for companies engaged in the production, distribution and marketing of crude oil and asphalt products. We manage our operations through four operating segments: (1) crude oil terminalling and storage services, (2) crude oil pipeline services, (3) crude oil trucking and producer field services, and (4) asphalt services.

### Our Operations

We were formed as a Delaware limited partnership in 2007 to own, operate and develop a diversified portfolio of complementary midstream energy assets. Our operating assets are owned by, and our operations are conducted through, our subsidiaries. Our General Partner has sole responsibility for conducting our business and for managing our operations. Our General Partner is jointly owned by Blueknight Energy Holding, Inc. (which is an affiliate of Vitol) and CB-Blueknight, LLC (which is an affiliate of Charlesbank). As such, Vitol and Charlesbank control our operations.

Our General Partner has no business or operations other than managing our business. In addition, outside of its investment in us, our General Partner owns no assets or property other than a minimal amount of cash which has been distributed by us to our General Partner in respect of its interest in us. Our partnership agreement imposes no additional material liabilities upon our General Partner or obligations to contribute to us other than those liabilities and obligations imposed on general partners under the Delaware Revised Uniform Limited Partnership Act.

The following diagram depicts our organizational structure, including our relationship with our affiliates and subsidiaries, as of December 31, 2012:

Our Strengths and Strategies

Strategically placed assets.  Our primary crude oil terminalling and storage facilities are located within the Cushing Interchange in Cushing, Oklahoma, one of the largest crude oil marketing hubs in the United States and the designated point of delivery specified in all New York Mercantile Exchange ("NYMEX") crude oil futures contracts. We believe that the Cushing Interchange will continue to serve as one of the largest crude oil marketing hubs in the United States.  In addition, we have approximately 1,264 miles of strategically positioned gathering and transportation pipelines in Oklahoma and Texas as well as 44 asphalt terminals located in 22 states that we believe are well positioned to provide services in the market areas they serve throughout the continental United States.

Growth opportunities.  Vitol and Charlesbank have indicated that they intend to use us as a growth vehicle to pursue the acquisition and expansion of midstream energy businesses and assets.  Vitol and Charlesbank have formed a company ("Development Company") that they have informed us is intended to be focused on developing projects that we may later have the opportunity to acquire.  Further, we may be involved in additional midstream projects for Vitol or Charlesbank outside of Development Company.  We have no interest in Development Company.   We also cannot say with any certainty whether or not Development Company or Vitol or Charlesbank will develop any projects or, if they do, which, if any, of these future acquisition opportunities may be made available to us, or if we will choose to pursue any such opportunity.

Experienced management team.  Our General Partner has an experienced and knowledgeable management team with extensive experience in the energy industry. We expect to directly benefit from this management team's strengths, including significant relationships throughout the energy industry with producers, marketers and refiners of crude oil and customers of our asphalt services.

Our relationship with Vitol and Charlesbank.  Vitol and Charlesbank jointly own our General Partner and therefore control our operations.  Vitol owns a diversified portfolio of midstream energy assets in the United States and internationally.  Charlesbank is a middle-market private equity investment firm based in Boston and New York.  These relationships may provide us with additional capital sources for future growth as well as increased opportunities to provide terminalling, storage, processing, gathering and transportation services.  While these relationships may benefit us, they may also be a source of potential conflicts. For example, Vitol and Charlesbank are not restricted from competing with us and they may acquire, construct or dispose of midstream or other assets in the future without any obligation to offer us the opportunity to purchase or construct those assets.

Industry Overview

Crude Oil Industry

We provide crude oil gathering, transportation, storage and terminalling services to producers, marketers and refiners of crude oil products. The market we serve, which begins at the source of production and extends to the point of distribution to the end user customer, is commonly referred to as the "midstream" market. Our crude oil operations are located primarily in Oklahoma, Kansas and Texas, where there are extensive crude oil production operations in place and our assets extend from gathering systems and trucking networks in and around these producing fields to transportation pipelines carrying crude oil to logistics hubs, such as the Cushing Interchange, where we have terminalling and storage facilities that aid our customers in managing the delivery of their crude oil.

Gathering and transportation. Pipeline transportation is generally considered the lowest cost method for shipping crude oil and refined petroleum products to other locations. Crude oil and refined products pipelines transport about two-thirds of the petroleum shipped in the United States. Crude oil pipelines transport oil from the wellhead to logistics hubs and/or refineries. Logistics hubs like the Cushing Interchange provide storage and connections to other pipeline systems and modes of transportation, such as tankers, railroads and trucks. Vessels and railroads provide additional transportation capabilities shipping crude oil between gathering storage systems, pipelines, terminals and storage centers and end-users. Vessel transportation is typically a cost-efficient mode of transportation that allows for the ability to transport large volumes of crude oil over long distances.

Trucking complements pipeline gathering systems by gathering crude oil from operators at remote wellhead locations not served by pipeline gathering systems. These trucks can also be used to transport crude oil to aggregation points and storage facilities, which are generally located along pipeline gathering and transportation systems. Trucking is generally limited to low volume, short haul movements where other alternatives to pipeline transportation are often unavailable. Trucking costs escalate sharply with distance, making trucking the most expensive mode of crude oil transportation. Despite being small in terms of both volume per shipment and distance, trucking is an essential component of the oil distribution system.

Terminalling and storage. Terminalling and storage facilities complement the crude oil pipeline gathering and transportation systems. Terminals are facilities where crude oil is transferred to or from a storage facility or transportation system, such as a gathering pipeline, to another transportation system, such as trucks or another pipeline. Terminals play a key role in moving crude oil to end-users such as refineries by providing storage and inventory management and distribution.

Storage and terminalling assets generate revenues through a combination of storage and throughput charges to third parties. Storage fees are generated when tank capacity is provided to third parties. Terminalling services fees, also referred to as throughput services fees, are generated when a terminal receives crude oil from a shipper and redelivers it to another shipper. Both storage and terminalling services fees are earned from refiners and gatherers that need segregated storage for refining feedstocks, pipeline operators, refiners or traders that need segregated storage for foreign cargoes, traders who make or take delivery under NYMEX contracts and producers and marketers that seek to increase their marketing alternatives.

Overview of the Cushing Interchange. The Cushing Interchange is one of the largest crude oil marketing hubs in the United States and the designated point of delivery specified in all NYMEX crude oil futures contracts. As the

NYMEX delivery point and a cash market hub, the Cushing Interchange serves as the primary source of refinery feedstock for Midwest refiners and plays an integral role in establishing and maintaining markets for many varieties of foreign and domestic crude oil. The following table lists certain of the entities with incoming pipelines connected to the Cushing Interchange, the proprietary terminals within the complex and outgoing pipelines from the Cushing Interchange for delivery throughout the United States:

| Incoming Pipelines to Cushing Interchange | Cushing Interchange Terminals | Outgoing Pipelines from Cushing Interchange |
|---|---|---|
| Blueknight Energy Partners, L.P. | Blueknight Energy Partners, L.P. | Blueknight Energy Partners, L.P. |
| BP p.l.c. | Enterprise Products Partners L.P. | BP p.l.c. |
| Enterprise Products Partners L.P. | Enbridge Energy Partners, L.P. | ConocoPhillips |
| Sunoco Logistics Partners, L.P. | Plains All American Pipeline, L.P. | Sunoco Logistics Partners, L.P. |
| Plains All American Pipeline, L.P. | ConocoPhillips | Enbridge Energy Partners, L.P. |
| Enbridge Energy Partners, L.P. | SemGroup Corporation | Osage Pipeline Company, LLC |
| SemGroup Corporation | Magellan Midstream Partners, L.P. | Plains All American Pipeline, L.P. |
| Basin Pipeline System | Deeprock Energy Resources LLC | Magellan Midstream Partners, L.P. |
| TransCanada Corp. | Kinder Morgan Energy Partners, L.P. | Centurion Pipeline L.P. |
| EOG Resources, Inc. | | Seaway Crude Pipeline Company LLC |
| White Cliffs Pipeline, LLC | | |

Due to our pipeline and terminalling infrastructure, we have the ability to receive and/or deliver, directly or indirectly, to all pipelines and terminals within the Cushing Interchange.

Asphalt Industry

Liquid asphalt cement is one of the oldest engineering materials. Liquid asphalt cement's adhesive and waterproofing properties have been used for building structures, waterproofing ships, mummification and numerous other applications.

Production of liquid asphalt cement begins with the production of crude oil. Liquid asphalt cement is a dark brown to black cementitious material that is primarily produced by petroleum distillation. When crude oil is separated in distillation towers at a refinery, the heaviest hydrocarbons with the highest boiling points settle at the bottom. These tar-like fractions, called residuum, require relatively little additional processing to become products such as asphalt base or residual fuel oil. Liquid asphalt cement production typically represents only a small portion of the total product production in the crude oil refining process. The liquid asphalt cement produced by petroleum distillation can be sold by the refinery either directly into the wholesale and retail liquid asphalt cement markets or to a liquid asphalt cement marketer.

In its normal state, asphalt cement is too viscous a liquid to be used at ambient temperatures. For paving applications, asphalt cement can be heated (as for hot mix asphalt), diluted or cut back with petroleum solvents (cutback asphalts), or emulsified in a water base with emulsifying chemicals by a colloid mill (asphalt emulsions). Hot mix asphalt is produced by mixing hot asphalt cement and heated aggregate (stone, sand and/or gravel). The hot mix asphalt is loaded into trucks for transport to the paving site, where it is placed on the road surface by paving machines and compacted by rollers. Hot mix asphalt is used for new construction, reconstruction and for thin maintenance overlays on existing roads.

Asphalt emulsions and cutback asphalts are used for a variety of applications including spraying as a tack coat between an old pavement and a new hot mix asphalt overlay, cold mix pothole patching material, and preventive maintenance surface applications such as chip seals. Asphalt emulsions are also used for fog seal, slurry seal, scrub seal, sand seal and microsurfacing maintenance treatments, for warm mix emulsion/aggregate mixtures, base stabilization and both central plant and in-place recycling. Asphalt emulsions and cutback asphalts are generally sold directly to government agencies but are also sold to contractors for use in applications such as chip seals.

The asphalt industry in the United States is characterized by a high degree of seasonality. Much of this seasonality is due to the impact that weather conditions have on road construction schedules, particularly in cold weather states.

Refineries produce liquid asphalt cement year round, but the peak asphalt demand season is during the warm weather months when most of the road construction activity in the United States takes place. Liquid asphalt cement marketers and finished asphalt product producers with access to extensive storage capacity possess the inherent advantage of being able to purchase supply from refineries on a year round basis and then sell finished asphalt products in the peak summer demand season.

Residual Fuel Oil Industry

Like asphalt cement, residual fuel oil is another by-product of the crude oil distillation process. Residual fuel oil is primarily used as a burner fuel in numerous industrial and commercial business applications including the utility industry, the shipping and paper industry, steel mills, tire manufacturing, schools and food processors.

The residual fuel oil industry in the United States is characterized by a high degree of seasonality with much of the seasonality driven by the impact of weather on the need to produce power for heating and cooling applications. The residual fuel oil market is largely a commodity market with price functioning as the primary decision-making criterion. However, many customers have unique product specifications driven by their particular business applications that require the blending of various components to meet those specifications.

Residual fuel oil is purchased from a variety of refiners by our customers and transported to our terminalling and storage facilities via numerous transportation methods including rail tank car, barge, ship and truck. Some of our customers use our asphalt assets to service their residual fuel oil business.

Crude Oil Terminalling and Storage Services

With approximately 7.8 million barrels of above-ground crude oil terminalling facilities and storage tanks, we are able to provide our customers the ability to effectively manage their crude oil inventories and enhance flexibility in their marketing and operating activities. Our crude oil terminalling and storage assets are located throughout our core operating areas with the majority of our crude oil terminalling and storage strategically located at the Cushing Interchange.

Our crude oil terminals and storage assets receive crude oil products from pipelines, including those owned by us, and distribute these products to interstate common carrier pipelines and regional independent refiners, among other third parties. Our crude oil terminals derive most of their revenues from terminalling services fees charged to customers.

The table below sets forth the total average barrels stored at and delivered out of our Cushing terminal in each of the periods presented and the total storage capacity at our Cushing terminal and at our other terminals at the end of such periods:

| | Year Ended December 31, | |
|---|---|---|
| | 2011 | 2012 |
| Average crude oil barrels stored per month at our Cushing terminal | 4,333,964 | 4,255,841 |
| Average crude oil delivered (Bpd) to our Cushing terminal | 63,696 | 77,917 |
| Total storage capacity at our Cushing terminal (barrels at end of period) | 6,600,000 | 6,600,000 |
| Total other storage capacity (barrels at end of period) | 1,217,109 | 1,190,943 |

The following table outlines the location of our crude oil terminals and their storage capacities and number of tanks as of December 31, 2012:

| Location | Storage Capacity (barrels) | Number of Tanks |
|---|---|---|
| Cushing, Oklahoma | 6,600,000 | 34 |
| Longview, Texas | 430,000 | 7 |
| Other[(1)] | 760,943 | 208 |
| Total | 7,790,943 | 249 |

(1) Consists of miscellaneous storage tanks located at various points along our pipeline and gathering system.

Cushing Terminal. One of our principal assets is our Cushing terminal, which is located within the Cushing Interchange in Cushing, Oklahoma. Currently, we own and operate 34 crude oil storage tanks with approximately 6.6 million barrels of storage capacity at this location. We own approximately 10 additional acres of land within the Cushing Interchange that is available for future expansion.

Our Cushing terminal was constructed over the last 50 years and has an expected remaining life of at least 20 years. Over 90% of our total storage capacity in our Cushing terminal has been built since 2002. We estimate that our storage tanks have a weighted average age of ten years.

The design and construction specifications of our storage tanks meet or exceed the minimums established by the American Petroleum Institute, or API. Our storage tanks also undergo regular maintenance inspection programs that are more stringent than established governmental guidelines. We believe that these design specifications and inspection programs will result in lower future maintenance capital costs to us.

A key attribute of our Cushing terminal is that through our pipeline and gathering system interface, we have access and connectivity to all the terminals located within the Cushing Interchange. This connectivity is a key attribute of our Cushing terminal because it provides us the ability to deliver to virtually any customer within the Cushing Interchange.

Our Cushing terminal can receive crude oil from our Mid-Continent system as well as other terminals owned by Magellan Midstream Partners, Enterprise Products Partners, Sunoco Logistics Partners, Plains All American, Seaway, Enbridge Energy Partners, SemCorp, Deeprock Energy Resources, EOG Resources, Inc. and two truck racks. Our Cushing terminal's pipeline connections to major markets in the Mid-Continent region provide our customers with marketing flexibility. Our Cushing terminal can deliver crude oil via pipeline and, in the aggregate, is capable of receiving and/or delivering 348,000 Bpd of crude oil.

Longview Terminal.  We own and operate the Longview terminal, located in Longview, Texas, consisting of seven tanks with a total storage capacity of 430,000 barrels. We use our Longview terminal in connection with our Longview system. A number of other potential customers have access to the Longview terminal. The Longview terminal was constructed beginning in the 1940s, and we believe it has a remaining life of at least 20 years.

Significant Customers.  For the twelve months ended December 31, 2012, Vitol accounted for $24.0 million, or 67%, of our total crude oil terminalling and storage revenue.  The loss of Vitol as a customer could have a material adverse effect on our business, cash flows and results of operations.  As of March 2013, we provide crude oil terminalling and storage services to Vitol under four agreements having storage capacities of 2.0 million barrels, 1.0 million barrels, 0.5 million barrels and 0.5 million barrels, respectively, and having terms expiring in May 2015, March 2014, October 2013 and October 2013, respectively.  No other customer accounted for more than 10% of our crude oil terminalling and storage revenue during 2012. For more information regarding the Vitol storage agreements, please see "Item 13-Certain Relationships and Related Party Transactions, and Director Independence-Agreements with Vitol."

Crude Oil Pipeline Services

We own and operate a crude oil gathering and transportation system in the Mid-Continent region of the United States with a combined length of approximately 770 miles and a 309 mile tariff-regulated crude oil gathering and transportation pipeline in the Longview, Texas area.  In addition, we own and operate the Eagle North Pipeline System in the Mid-Continent region of the United States with a length of approximately 185 miles.  The Eagle North Pipeline System was placed in service in December of 2010.

| System | Asset Type | Approximate Length (miles) | Average Throughput for Year Ended December 31, 2011 (Bpd) | Average Throughput for Year Ended December 31, 2012 (Bpd) | Pipe Diameter Range |
|---|---|---|---|---|---|
| Mid-Continent | Gathering and transportation pipelines | 770 | 20,019 | 20,109 | 4" to 20" |
| Longview | Gathering and transportation pipelines | 309 | 27,624 | 28,667 | 6" to 8" |
| Eagle North | Gathering and transportation pipelines | 185 | 11,960 | 18,130 | 8" |

Mid-Continent System.  Our Mid-Continent gathering and transportation system provides access to our Cushing terminal and other storage facilities. The Oklahoma portion of our Mid-Continent system consists of approximately 746 miles of various sized pipeline, of which approximately 430 miles is comprised of idle, inactive gathering lines. Crude oil gathered into the Oklahoma portion of our Mid-Continent system is transported to our Cushing terminal or delivered to local area refiners. The Mid-Continent system also includes a 24-mile gathering and transportation system in the Texas Panhandle near Dumas, Texas. Crude oil collected through the Texas Panhandle portion of our Mid-Continent system is transported by pipeline to a station where it is then delivered to market via tanker truck. For the years ended December 31, 2011 and 2012, this system gathered an average of approximately 20,019 Bpd and 20,109 Bpd of crude oil, respectively. The Mid-Continent system was constructed in various stages beginning in the 1940s and we believe it has a remaining life of at least 20 years.

Longview System. Our Longview system consists of approximately 309 miles of tariff-regulated crude oil gathering pipeline, of which approximately 95 miles is comprised of idle, inactive gathering lines. The East Texas portion of this system delivers to crude oil terminalling, refinery and storage facilities at various delivery points in the East Texas region. Our Longview system also includes a small pipeline gathering system (Thompson-to-Webster) located near Houston, Texas. The Thompson-to-Webster gathering system consists of 42 miles of 6” and 8” pipeline. Deliveries made from this gathering system are transported to refineries in the Baytown/Texas City area. For the years ended December 31, 2011 and 2012, our Longview system gathered an average of approximately 27,624 Bpd and 28,667 Bpd, respectively. Shippers on the Longview system include Eastex Crude, ExxonMobil Corporation, Vitol, Truth Resources, L.P., Delek Refining, LTD, Jetta Production Company, Plains All American L.P., Sunoco Logistics Partners L.P. and Denbury Onshore L.L.C. The Longview system was constructed in various stages beginning in the 1940s and we believe it has a remaining life of at least 20 years.

Eagle North Pipeline System. In May 2008, we purchased our Eagle North Pipeline System, which includes a 185-mile, 8-inch pipeline, of which approximately 10 miles is idle, that originates in Cushing, Oklahoma and terminates in Ardmore, Oklahoma. In August 2010, we entered into a Throughput Capacity Agreement (the "Throughput Capacity Agreement") with Vitol. We have entered into a throughput agreement with a third party relating to this pipeline. In addition, pursuant to the Throughput Capacity Agreement, Vitol purchased 100% of the throughput capacity of the Eagle North Pipeline System with its rights being subordinate to the rights of the third party under its throughput agreement with us. For more information relating to the Throughput Capacity Agreement, please see "Item 13. Certain Relationships and Related Transactions, and Director Independence-Agreements with Vitol-Vitol Throughput Capacity Agreement."

In 2010, we spent an additional $6.7 million, including capitalized interest of $3.8 million, to ready this pipeline for service and to extend it from Drumright, Oklahoma to Cushing, Oklahoma. This asset was placed into service in December of 2010.

Significant Customers. Vitol, Valero Marketing & Supply Co and ExxonMobil Corporation each accounted for at least 15% but not more than 30% of crude oil pipeline services revenue in 2012. The loss of any of these customers could have a material adverse effect on our business, cash flows and results of operations. No other customer accounted for more than 10% of our crude oil pipeline services revenue during 2012.

Crude Oil Trucking and Producer Field Services

We provide two types of trucking services: crude oil trucking and producer field services.

Crude Oil Trucking Services. To complement our pipeline gathering and transportation business, we use our approximately 164 owned or leased tanker trucks, which have an average tank size of approximately 200 barrels, to move crude oil to aggregation points, pipeline injection stations and storage facilities. Our tanker trucks moved an average of 46,826 Bpd and 55,302 Bpd, respectively, for the years ended December 31, 2011 and 2012 from wellhead locations not served by pipeline gathering systems to aggregation points and storage facilities. Several of our trucking services operating areas, such as Midland, Texas, are not currently served by our gathering and transportation pipeline systems. In these areas, our trucking operations extend our ability to gather and aggregate crude oil on our systems. This ability allows the crude oil marketing customers we serve to increase the level of service they are able to provide to their customers and facilitates the transportation of incremental volumes on our system. The following table outlines the distribution of our trucking assets among our operating areas as of December 31, 2012:

| Location | Number of Trucks |
|---|---|
| Oklahoma | 59 |
| Kansas | 27 |
| Texas | 60 |
| New Mexico | 18 |
| Total | 164 |

Producer Field Services. We provide a number of producer field services for companies such as Eagle Rock Energy, DCP Midstream and ConocoPhillips. These services include gathering condensates by way of bobtail trucks for natural gas companies to hauling produced water to disposal wells, providing hot and cold fresh water, chemical and down hole well treating, wet oil clean up and building and maintaining separation facilities. We provide these services at contractual hourly rates. Our producer service fleet consists of approximately 115 trucks in a number of different sizes.

Significant Customers. Vitol and MV Purchasing, LLC each accounted for at least 10% but not more than 30% of crude oil trucking and producer field services revenue in 2012. The loss of either of these customers could have a material adverse effect on our business, cash flows and results of operations. No other customer accounted for more than 10% of our crude oil trucking and producer field services revenue during 2012.

Asphalt Services

With approximately 7.2 million barrels of total asphalt product and residual fuel oil storage capacity, we are able to provide our customers the ability to effectively manage their asphalt product storage and processing and marketing activities. Our 44 terminals are located in 22 states and as such are well-positioned to provide asphalt services in the market areas they serve throughout the continental United States.

We serve the asphalt industry by providing our customers access to their market areas through a combination of the leasing of certain of our asphalt facilities and the provision of storage and processing services at other of our asphalt and residual fuel oil facilities. In our asphalt services segment, we generate revenues by charging a fee for the lease of a facility or for services provided as asphalt products are terminalled, stored and/or processed in our facilities.

In addition, as of December 31, 2012, we have leases and storage agreements with third party customers relating to 43 of our 44 asphalt facilities.  The majority of the leases and storage agreements related to these facilities have terms that expire between the end of 2016 and the end of 2018.  We operate the asphalt facilities pursuant to the storage agreements while our contract counterparties operate the asphalt facilities that are subject to the lease agreements.

At facilities where we have storage contracts, we receive, store and/or process our customer's asphalt products until we deliver these products to our customers or other third parties.  Our asphalt assets include the logistics assets, such as docks and rail spurs and the piping and pumping equipment necessary to facilitate the unloading of liquid asphalt cement into our terminalling and storage facilities as well as the processing and manufacturing equipment required for the processing of asphalt emulsions, asphalt cutbacks, polymer modified asphalt cement and other related finished asphalt products. After initial unloading, the liquid asphalt cement is moved via heat-traced pipelines into large storage tanks. These tanks are insulated and contain heating elements that allow the asphalt cement to be stored in a heated state. The asphalt cement can then be directly sold by our customers to end users or used as a raw material for the processing of asphalt emulsions, asphalt cutbacks, polymer modified asphalt cement and related finished asphalt products that we process in accordance with the formulations and specifications provided by our customers.  Dependent on the product, the processing of asphalt entails combining asphalt cement and various other products such as emulsifying chemicals and polymers to achieve the desired specification and application requirements.

At leased facilities, our customers conduct the operations at the asphalt facility, including the storage and processing of asphalt products, and we collect a monthly rental fee relating to the lease of such facility.  Generally, under the terms of these leases, (i) title to the asphalt, raw materials, or finished asphalt products received, unloaded, stored, or otherwise handled at such asphalt facility is in the name of the lessee, (ii) the lessee is responsible for complying with environmental, health, safety, transportation and security laws, (iii) the lessee is required to obtain and maintain necessary permits, licenses, plans, approvals, or other such authorizations and is responsible for insuring such asphalt facility, and (iv) most routine maintenance and repair of such asphalt facility is the responsibility of the lessee.

We do not take title to, or marketing responsibility for, the liquid asphalt product that we terminal, store and/or process. As a result, our asphalt operations have minimal direct exposure to changes in commodity prices, but the volumes of liquid asphalt cement we receive, store and/or process are indirectly affected by commodity prices.

The following table provides an overview of our asphalt facilities as of December 31, 2012:

| Location | Number of Facilities | Total Tankage (in thousands of Bbls)(1) |
|---|---|---|
| Arkansas | 1 | 21 |
| California | 1 | 66 |
| Colorado | 4 | 401 |
| Georgia | 1 | 38 |
| Idaho | 1 | 285 |
| Illinois | 2 | 232 |
| Indiana | 1 | 156 |
| Kansas | 4 | 492 |
| Michigan | 1 | 140 |
| Missouri | 3 | 643 |
| Montana | 1 | 123 |
| Nebraska | 1 | 292 |
| New Jersey | 1 | 459 |
| Nevada | 1 | 280 |
| Ohio | 1 | 38 |
| Oklahoma | 6 | 904 |
| Pennsylvania | 2 | 72 |
| Tennessee | 3 | 470 |
| Texas | 3 | 779 |
| Utah | 2 | 300 |
| Virginia | 1 | 547 |
| Washington | 3 | 470 |
| Total | 44 | 7,208 |

(1) Total tankage refers to the approximate total capacity of all tanks.

Our asphalt assets range in age from two years to over fifty years and we expect that our storage tanks and related assets will have an average remaining life in excess of 20 years.

Significant Customers. Ergon Asphalt & Emulsions, Inc., Heartland Asphalt Materials, Inc., NuStar Marketing LLC and Suncor Energy USA each accounted for at least 10% but not more than 30% of asphalt services revenue in 2012. The loss of any of these customers could have a material adverse effect on our business, cash flows and results of operations. No other customer accounted for more than 10% of our asphalt services revenue during 2012.

Competition

We are subject to competition from other crude oil gathering, transportation, terminalling and storage operations that may be able to supply our customers with the same or comparable services on a more competitive basis. We compete with national, regional and local gathering, storage and pipeline companies and liquid asphalt cement storage and processing companies, including the major integrated oil companies, of widely varying sizes, financial resources and experience.

With respect to our crude oil gathering and transportation services, these competitors include Enterprise Products Partners L.P., Plains All American Pipeline, L.P., Magellan Midstream Partners, L.P. and Sunoco Logistics Partners L.P., among others. With respect to our crude oil storage and terminalling services, these competitors include Magellan Midstream Partners, L.P., Enbridge Energy Partners, L.P. and Plains All American Pipeline, L.P., among others.  Several of our competitors conduct portions of their operations through publicly traded partnerships with structures similar to ours, including Plains All American Pipeline, L.P., Enterprise Products Partners L.P., Sunoco Logistics Partners L.P. and Magellan Midstream Partners, L.P.  Our ability to compete could be harmed by factors we cannot control, including:

- the perception that another company can provide better service;

- the availability of crude oil alternative supply points, or crude oil supply points located closer to the operations of our customers; and
- a decision by our competitors to acquire or construct crude oil midstream assets and provide gathering, transportation, terminalling or storage services in geographic areas, or to customers, served by our assets and services.

The asphalt industry is highly fragmented and regional in nature. Participants range in size from major oil companies to small family-owned proprietorships. Participants in the asphalt business include refiners such as BP p.l.c., Flint Hills Resources, L.P., CHS, Inc., Exxon Mobil Corporation, ConocoPhillips Company, NuStar Energy L.P., Ergon, Inc., Marathon Petroleum Company LLC, Alon USA LP, Suncor Energy Inc. and Valero Energy Corporation; resellers such as NuStar Energy L.P., Idaho Asphalt Supply, Inc. and Asphalt Materials, Inc.; and large road construction firms such as OldCastle Materials, Inc. and Colas SA. We compete for asphalt services with the noted national, regional and local industry participants as well as liquid asphalt cement terminalling and storage companies including the major integrated oil companies and a variety of others including KinderMorgan Energy Partners, International-Matex Tank Terminals and Houston Fuel Oil Terminal Company.

If we are unable to compete with services offered by other midstream enterprises, our ability to make distributions to our unitholders may be adversely affected. Additionally, we also compete with national, regional and local companies for asset acquisitions and expansion opportunities. Some of these competitors are substantially larger than us and have greater financial resources and lower costs of capital than we do.

Interstate Pipeline Regulation

Currently, we have one tariff rate on the Longview System that is regulated by the Federal Energy Regulatory Commission, or FERC, and other tariff rates that are regulated by the Texas Railroad Commission.

Longview System. FERC, pursuant to the Interstate Commerce Act of 1887, as amended, or ICA, the Energy Policy Act of 1992 (“Energy Policy Act”) and rules and orders promulgated thereunder, regulates the tariff rates for our Longview system. FERC requires that interstate oil pipelines file tariffs that contain rules and regulations governing the rates and charges for services performed. These tariffs apply to the interstate movement of crude and liquid petroleum products. Pursuant to the ICA, the rates, terms and conditions for providing service on ICA-regulated pipelines must be just and reasonable, and the service must be provided on a non-discriminatory basis. The ICA permits interested persons to challenge proposed new or changed rates and authorizes FERC to suspend the effectiveness of such rates for a period of up to seven months and to investigate such rates. If, upon completion of an investigation, FERC finds that the new or changed rate is unlawful, it is authorized to require the carrier to refund the revenues in excess of the prior tariff during the term of the investigation. FERC may also investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained for a period of up to two years prior to the filing of a complaint.

Our FERC-regulated rate is deemed just and reasonable, or grandfathered, under the Energy Policy Act. The Energy Policy Act limits the circumstances under which a complaint can be made against such grandfathered rates. In order to challenge grandfathered rates, a party would have to show that it was previously contractually barred from challenging the rates, that the economic circumstances of the liquids pipeline that were a basis for the rate or the nature of the service underlying the rate had substantially changed or that the rate was unduly discriminatory or preferential.

We cannot predict what rates we will be allowed to charge in the future for service on FERC-regulated systems. Because rates charged for transportation services must be competitive with those charged by other transporters, the rates set forth in our tariffs will be determined based on competitive factors in addition to regulatory considerations.

Gathering and Intrastate Pipeline Regulation.  All intrastate pipelines in the state of Texas are regulated by the Texas Railroad Commission and intrastate pipelines in the state of Oklahoma are regulated by the Oklahoma Corporation Commission. In the states in which we operate, regulation of crude gathering facilities and intrastate crude pipeline facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and complaint-based rate regulation. For example, our intrastate crude pipeline facilities in Texas must have a tariff on file and charge just and reasonable rates for service, which must be provided on a non-discriminatory basis. Although state regulation is typically less onerous than at FERC, proposed and existing rates subject to state regulation and the provision of non-discriminatory service are subject to challenge by complaint.

Pipeline Safety. Our pipelines are subject to state and federal laws and regulations governing design, construction, operation and maintenance of the lines; qualifications of pipeline personnel; public awareness; emergency response and other aspects of pipeline safety. These laws and regulations are subject to change, resulting in potentially more stringent requirements and increased costs. Applicable pipeline safety regulations establish minimum safety requirements and, for pipelines that pose a greater risk to populated areas or environmentally sensitive areas, impose a more rigorous requirement for the implementation of pipeline integrity management programs for our pipelines. In 2006, the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006, or PIPES, reauthorized and amended the Department of Transportation's, or DOT's, pipeline safety programs. Included in PIPES is a provision eliminating the regulatory exemption contained in Part 195 for hazardous liquid pipelines operated at low stress. Final rules under PIPES were promulgated in July 2008 and extend all existing safety regulations, including integrity management requirements, to large-diameter low-stress pipelines within a defined "buffer" area around an "unusually sensitive area," which includes areas that contain sole-source drinking water, endangered species or other ecological resources. Operators of these and all other low-stress pipelines are required by the rules to comply with annual reporting requirements. On January 3, 2012, President Obama signed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011. The Act increases the maximum civil penalties for pipeline safety administrative enforcement actions; requires the DOT to study and report on the expansion of integrity management requirements, the sufficiency of existing gathering line regulations to ensure safety and the feasibility of leak detection systems for hazardous liquid pipelines; requires pipeline operators to verify their records on maximum allowable operating pressure; and imposes new emergency response and incident notification requirements. Both states in which we operate pipelines, Oklahoma and Texas, incorporate into their state rules those federal safety standards for hazardous liquids pipelines contained in Title 49, Part 195 of the Federal Code of Regulations. As a result, the issuance of any new pipeline safety regulations, including additional requirements for integrity management, are likely to increase the operating costs of our pipelines subject to such new requirements, and such future costs may be material.

Trucking Regulation. We operate a fleet of trucks to transport crude oil and oilfield materials as a private, contract and common carrier. We are licensed to perform both intrastate and interstate motor carrier services. As a motor carrier, we are subject to certain safety regulations issued by the DOT. The trucking regulations cover, among other things, driver operations, maintaining log books, truck manifest preparations, the placement of safety placards on the trucks and trailer vehicles, drug and alcohol testing, safety of operation and equipment and many other aspects of truck operations. We are also subject to requirements of the federal Occupational Safety and Health Act, as amended, or OSHA, with respect to our trucking operations.

Environmental, Health and Safety Risks

General. Our midstream crude oil gathering, transportation, terminalling and storage operations, together with our asphalt assets, are subject to stringent federal, state and local laws and regulations relating to the discharge of materials into the environment or otherwise relating to protection of the environment. As with the midstream and liquid asphalt cement industries generally, compliance with current and anticipated environmental laws and regulations increases our overall cost of business, including our capital costs to construct, maintain and upgrade equipment and facilities. Failure to comply with these laws and regulations may result in the assessment of significant administrative, civil and criminal penalties, the imposition of investigatory and remedial liabilities, and even the issuance of injunctions that may restrict or prohibit some or all of our operations. We believe that our operations are in substantial compliance with applicable laws and regulations. However, environmental laws and regulations are subject to change, resulting in potentially more stringent requirements, and we cannot provide any assurance that the cost of compliance with current and future laws and regulations will not have a material effect on our results of operations or earnings.

There are also risks of accidental releases into the environment inherent in the nature of both our midstream and liquid asphalt cement operations, such as leaks or spills of petroleum products or hazardous materials from our pipelines, trucks, terminals and storage facilities. A discharge of petroleum products or hazardous materials into the environment could, to the extent such event is not covered by insurance, subject us to substantial expense, including costs related to environmental clean-up or restoration, compliance with applicable laws and regulations, and any personal injury, natural resource or property damage claims made by neighboring landowners and other third parties.

The following is a summary of the more significant current environmental, health and safety laws and regulations to which our business operations are subject and for which compliance may require material capital expenditures or have a material adverse impact on our results of operations, financial position and cash flows.

Water. The federal Clean Water Act and analogous state and local laws impose restrictions and strict controls regarding the discharge of pollutants into waters of the United States and state waters. Permits must be obtained to discharge pollutants into these waters. The Clean Water Act and analogous laws provide significant penalties for unauthorized discharges and impose substantial potential liabilities for cleaning up spills and leaks into water. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. We believe that we are in substantial compliance with any such applicable state requirements.

The federal Oil Pollution Act, as amended, or OPA, was enacted in 1990 and amends provisions of the Federal Water Pollution Control Act of 1972, the Clean Water Act, and other statutes as they pertain to prevention and response to oil spills. The OPA, and analogous state and local laws, subject owners of facilities used for storing, handling or transporting oil, including trucks and pipelines, to strict, joint and potentially unlimited liability for containment and removal costs, natural resource damages and certain other consequences of an oil spill, where such spill is into navigable waters, along shorelines or in the exclusive economic zone of the United States. The OPA, the Clean Water Act and other analogous laws also impose certain spill prevention, control and countermeasure requirements, such as the preparation of detailed oil spill emergency response plans and the construction of dikes and other containment structures to prevent contamination of navigable or other waters in the event of an oil overflow, rupture or leak. We believe that we are in substantial compliance with applicable OPA and analogous state and local requirements.

Air Emissions.  Our operations are subject to the federal Clean Air Act (“CAA”), as amended, as well as to comparable state and local laws. We believe that our operations are in substantial compliance with these laws in those areas in which we operate. Amendments to the CAA enacted in 1990 imposed a federal operating permit requirement for major sources of air emissions. Our crude oil terminal located in Cushing, Oklahoma holds such a permit, which is referred to as a “Title V permit.”  In 2010, the EPA entered into a settlement requiring it to reevaluate regulations for the control of air emissions from the oil and natural gas industry. As a result, the EPA proposed regulations in July 2011 that would establish new air pollution standards for the oil and natural gas industry, including new source performance standards for volatile organic compounds and sulfur dioxide and an air toxics standards for oil and natural gas production and for natural gas transmission and storage.  On April 17, 2012, the EPA approved final rules under the CAA that establish new air emission controls for oil and natural gas production, pipelines and processing operations. These rules became effective on October 15, 2012. In October 2012, several challenges to the new rules were filed by various parties, including environmental groups and industry associations. In a January 1, 2013 unopposed motion to hold this litigation in abeyance, the EPA indicated that it may reconsider some aspects of the rules. Depending on the outcome of such proceedings, the rules may be modified or rescinded or the EPA may issue new rules. The costs of compliance with any modified or newly issued rules cannot be predicted. Additionally, on December 11, 2012, seven states submitted a notice of intent to sue the EPA to compel a determination on the appropriateness of standards of performance limiting methane emissions from the oil and gas sector and requesting that the EPA issue emission guidelines for the control of methane emissions from existing oil and gas sources. Depending on whether such rules are promulgated and the applicability and restrictions in any promulgated rule, compliance with such rules could result in additional compliance costs for us and for others in our industry. In response to these and other regulatory developments, we may be required to incur certain capital expenditures in the next several years for air pollution control equipment and operational changes in connection with obtaining or maintaining permits and approvals and complying with applicable regulations addressing air emission related issues.  Although we can provide no assurance, we believe future compliance with the CAA, as amended, will not have a material adverse effect on our financial condition, results of operations or cash flows.

Climate Change.  Legislative and regulatory measures to address concerns that emissions of certain gases, commonly referred to as “greenhouse gases” (“GHGs”), may be contributing to warming of the Earth’s atmosphere are in various phases of discussions or implementation at the international, national, regional, and state levels. The oil and gas industry is a direct source of certain GHG emissions, namely carbon dioxide and methane, and future restrictions on such emissions could impact our future operations. In the United States, federal legislation requiring GHG controls is under consideration. In addition, the Environmental Protection Agency (the “EPA”) has promulgated a series of rulemakings and other actions intended to result in the regulation of GHGs as pollutants under the CAA.  In April

2010, EPA promulgated final motor vehicle GHG emission standards, which apply to vehicle model years 2012 - 2016. EPA has taken the position that the motor vehicle GHG emission standards triggered CAA permitting requirements for certain affected stationary sources of GHG emissions beginning on January 2, 2011. In May 2010, EPA finalized the Prevention of Significant Deterioration and Title V GHG Tailoring Rule, which phases in federal new source review and Title V permitting requirements for certain affected stationary sources of GHG emissions, beginning January 2, 2011. These EPA rulemakings could affect our operations and ability to obtain air permits for new or modified facilities. Furthermore, in 2009, the EPA issued a “Mandatory Reporting of Greenhouse Gases” final rule, establishing a comprehensive scheme of regulations that require monitoring and reporting of GHG emissions on an annual basis by operators of stationary sources in the U.S. emitting more than established annual thresholds of carbon dioxide-equivalent GHG emissions. Monitoring obligations began in 2010. The first emissions reports required under the new rule were due on or before March 31, 2011, and the scope of the rule was expanded for 2011 to cover additional petroleum and natural gas production, processing, and transmission sources that were not previously covered by the rule. Although this new rule does not control GHG emission levels from any facilities, it has caused us to incur monitoring and reporting costs.

Legislation and regulations relating to control or reporting of GHG emissions are also in various stages of discussions or implementation in many of the states in which we operate. Passage of climate change legislation or other federal or state legislative or regulatory initiatives that regulate or restrict GHG emissions in areas in which we conduct business could adversely affect the demand for our products and services, and depending on the particular program adopted could increase the costs of our operations, including costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our GHG emissions (e.g., from natural gas fired combustion units), pay any taxes related to our GHG emissions and/or administer and manage a GHG emissions program.  At this time, it is not possible to accurately estimate how laws or regulations addressing GHG emissions would impact our business.  Although we would not be impacted to a greater degree than other similarly situated midstream transporters of petroleum products, a stringent greenhouse gas control program could have an adverse effect on our cost of doing business and could reduce demand for the products we transport.

In addition to potential impacts on our business directly or indirectly resulting from climate-change legislation or regulations, our business also could be negatively affected by climate-change related physical changes or changes in weather patterns.  An increase in severe weather patterns could result in damages to or loss of our physical assets, impact our ability to conduct operations and/or result in a disruption of our customer’s operations.  These types of physical changes could also affect entities that provide goods and services to us and indirectly have an adverse affect on our business as a result of increases in costs or availability of goods and services.  Changes of this nature could have a material adverse impact on our business.

Solid Waste Disposal and Environmental Remediation.  The Comprehensive Environmental Response, Compensation, and Liability Act, as amended, or CERCLA, also known as Superfund, as well as comparable state and local laws, impose liability without regard to fault or the legality of the original act, on certain classes of persons associated with the release of a “hazardous substance” into the environment. These persons include the owner or operator of the site or sites where the release occurred and companies that disposed of, or arranged for the disposal of, the hazardous substances found at the site. Under CERCLA, such persons may be subject to strict and, under certain circumstances, joint and several liability for cleanup costs, for damages to natural resources, and for the costs of certain health studies. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by releases of hazardous substances or other pollutants. We generate materials in the course of our operations that are regulated as hazardous substances. Beyond the federal statute, many states have enacted environmental response statutes that are analogous to CERCLA.

We generate wastes, including “hazardous wastes,” that are subject to the requirements of the federal Resource Conservation and Recovery Act, as amended, or RCRA, as well as to comparable state and local laws. While normal costs of complying with RCRA would not be expected to have a material adverse effect on our financial conditions, we could incur substantial expense in the future if the RCRA exclusion for oil and gas waste were eliminated. Should our oil and gas wastes become subject to RCRA, we would also become subject to more rigorous and costly disposal requirements, resulting in additional capital expenditures or operating expenses for us.

We currently own or lease properties where hazardous substances are being handled or have been handled for many years. Although we believe that operating and disposal practices that were standard in the midstream and liquid asphalt cement industries at the time were utilized at properties leased or owned by us, historical releases of hazardous substances or associated generated wastes have occurred on or under the properties owned or leased by us, or on or under other locations where these wastes were taken for disposal. In addition, many of these properties have been operated in the past by third parties whose treatment and disposal or release of hazardous substances or associated generated wastes were not under our control. These properties and the materials disposed on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove or remediate previously spilled hazardous materials or associated generated wastes (including wastes disposed of or released by other site occupants or by prior owners or operators), or to clean up contaminated property (including contaminated groundwater).

Contamination resulting from the release of hazardous substances or associated generated wastes is not unusual within the midstream and liquid asphalt cement industries.  Other assets we have acquired or will acquire in the future may have environmental remediation liabilities for which we are not indemnified. In the future, we likely will experience releases of hazardous materials, including petroleum products, into the environment from our pipeline terminalling and storage operations, or discover releases that were previously unidentified. Although we maintain a program designed to prevent and, as applicable, to detect and address such releases promptly, damages and liabilities incurred due to environmental releases from our assets may substantially affect our business.

OSHA.  We are subject to the requirements of OSHA, as well as to comparable state and local laws that regulate the protection of worker health and safety. In addition, the OSHA hazard communication standard requires that certain information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with OSHA requirements, including general midstream and liquid asphalt cement industry standards, record keeping requirements and monitoring of occupational exposure to regulated substances.

Anti-Terrorism Measures. The federal Department of Homeland Security Appropriations Act of 2007 requires the Department of Homeland Security, or DHS, to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including oil and gas facilities that are deemed to present "high levels of security risk." The DHS issued an interim final rule in April 2007 known as the Chemical Facility Anti-Terrorism Standards ("CFATS") regarding risk-based performance standards to be attained pursuant to the act and, on November 20, 2007, further issued an Appendix A to CFATS that establish chemicals of interest and their respective threshold quantities that will trigger compliance with these interim rules. We currently do not handle, use, store, or process any "Chemicals of Interest" ("COI") listed in Appendix A above their respective threshold quantities, and are therefore not subject to requirements of CFATS. We will continue to monitor the CFATS for regulatory changes that could impact our operations in the future.

Operational Hazards and Insurance

Pipelines, terminals, storage tanks and similar facilities may experience damage as a result of an accident or natural disaster. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We have maintained insurance of various types and varying levels of coverage that we consider adequate under the circumstances to cover our operations and properties, including coverage for pollution related events. However, such insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities. Notwithstanding what we believe is a favorable claims history, the overall cost of the insurance program as well as the deductibles and overall retention levels that we maintain have increased. Through the utilization of deductibles and retentions we self insure the "working layer" of loss activity to create a more efficient and cost effective program. The working layer consists of high frequency/low severity losses that are best retained and managed in-house. As we continue to grow, we will continue to monitor our retentions as they relate to the overall cost and scope of our insurance program.

Employees

As of December 31, 2012, we employed approximately 535 persons. None of these employees are represented by labor unions or covered by any collective bargaining agreement. We believe that relations with these employees are satisfactory.

Mr. James C. Dyer, who was our Chief Executive Officer and a director until September 2012, was also an officer of Vitol. Certain of our employees provided services to Vitol pursuant to an Omnibus Agreement between us and Vitol, effective as of January 1, 2010 (the "Vitol Omnibus Agreement"). The Vitol Omnibus Agreement was terminated on March 27, 2012. For more information regarding the Vitol Omnibus Agreement, please see "Item 13-Certain Relationships and Related Party Transactions, and Director Independence-Agreements with Vitol."

Financial Information about Segments

Information regarding our operating revenues, profit and loss and identifiable assets attributable to each of our segments is presented in Note 19 to our consolidated financial statements included in this annual report on Form 10-K.

Available Information

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, www.bkep.com, as soon as is reasonably practicable after their filing with the SEC. Information contained on our website is not incorporated by reference in this report or any of our other filings. The filings are also available through the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. Information on the operation of the Public Reference Room is available by calling 1-800-SEC-0330. The SEC also maintains a website that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC. The SEC's website is 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 similar business. You should carefully consider the following risk factors together with all of the other information included in this report. If any of the following risks were actually to occur, our business, financial condition, results of operations and cash flows could be materially adversely affected. In that case, we might not be able to pay distributions on our units, the trading price of our units could decline and our unitholders could lose all or part of their investment.

Risks Related to our Business

We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our General Partner, to enable us to make cash distributions to holders of our units at our current distribution rate.

In order to make cash distributions on our Preferred Units at the preference distribution rate of $0.17875 per unit per quarter, or $0.715 per unit per year, and on our common units at the minimum quarterly distribution of $0.11 per unit per quarter, or $0.44 per unit per year, we will require available cash of approximately $8.1 million per quarter, or $32.3 million per year. We may not have sufficient available cash from operating surplus each quarter to enable us to make cash distributions on our Preferred Units at the preference rate or on our common units at the minimum quarterly distribution rate. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things, the risks described herein.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, including:

- the level of capital expenditures we make;
- the cost of acquisitions;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets;
- restrictions contained in our credit facility or other debt agreements; and
- the amount of cash reserves established by our General Partner.

Our cash available for distributions to our unitholders could be negatively impacted if we are unable to extend existing storage contracts or enter into new storage contracts at our Cushing terminal.

We have a total of 6.6 million barrels of storage capacity at the Cushing terminal. Customer storage contracts for 2.1 million barrels of storage at this location are operating on a month to month basis or expire in 2013. We may not be able to extend, renegotiate or replace these contracts when they expire, and the terms of any renegotiated contracts may not be as favorable as the contracts they replace. In addition, to the degree that we operate outside of long-term contracts, our revenues can be significantly more volatile than would be the case with a pricing structure negotiated through a long-term storage contract. If we cannot successfully renew significant contracts or must renew them on less favorable terms, our revenues from these arrangements could decline which could have a material adverse effect on our financial condition, results of operations and cash flows.

We depend on certain key customers for a portion of our revenues and are exposed to credit risks of these customers. The loss of or material nonpayment or nonperformance by any of these key customers could adversely affect our cash flow and results of operations.

We rely on certain key customers for a portion of revenues. For example, Vitol represented approximately $24.0 million, or 67%, of our total crude oil terminalling and storage revenue, $5.7 million, or 26%, of our crude oil pipeline services revenue, and $17.7 million, or 28%, of total crude oil trucking and producer field services revenue in

2012. Vitol is a private company and we have limited information regarding its financial condition. Vitol comprised 23% of total accounts receivable at December 31, 2012. No other customer accounted for more than 10% of crude oil terminalling and storage services revenue in 2012. Valero Marketing and Supply Co. and ExxonMobil Corporation each accounted for at least 15% but no more than 30% of crude oil pipeline services revenue in 2012. Vitol and MV Purchasing, LLC accounted for at least 10% but not more than 30%, respectively, of crude oil trucking and producer field services revenue in 2012. Ergon Asphalt & Emulsions, Heartland Asphalt Materials, Inc., NuStar Marketing LLC and Suncor Energy USA accounted for at least 10% but not more than 30% of asphalt services revenue in 2012.



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We may be unable to negotiate extensions or replacements of contracts with key customers on favorable terms. In addition, some of these key customers may experience financial problems that could have a significant effect on their creditworthiness. Severe financial problems encountered by our customers could limit our ability to collect amounts owed to us, or to enforce performance of obligations under contractual arrangements. Additionally, many of our customers finance their activities through cash flow from operations, the incurrence of debt or the issuance of equity. The combination of reduction of cash flow resulting from declines in commodity prices, a reduction in borrowing bases under credit facilities and the lack of availability of debt or equity financing may result in a significant reduction of our customers' liquidity and limit their ability to make payments or perform on their obligations to us. Furthermore, some of our customers may be highly leveraged and subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to us. The loss of all or even a portion of the contracted volumes of these key customers, as a result of competition, creditworthiness or otherwise, could have a material adverse effect on our business, cash flows, ability to make distributions to our unitholders, the price of our units, our results of operations and ability to conduct our business.

We are exposed to the credit risks of our third-party customers in the ordinary course of our gathering activities. Any material nonpayment or nonperformance by our third-party customers could reduce our ability to make distributions to our unitholders.

We are subject to risks of loss resulting from nonpayment or nonperformance by our third-party customers. Some of our customers may be highly leveraged and subject to their own operating and regulatory risks. In addition, any material nonpayment or nonperformance by our customers could require us to pursue substitute customers for our affected assets or provide alternative services. Any such efforts may not be successful or may not provide similar fees. These events could have a material adverse effect on our financial condition and results of operations.

The amount of cash we have available for distribution to holders of our units depends primarily on our cash flow and not solely on earnings reflected in our financial statements. Consequently, even if we are profitable and are otherwise able to pay distributions, we may not be able to make cash distributions to holders of our units.

Our unitholders should be aware that the amount of cash we have available for distribution depends primarily upon our cash flow and not solely on earnings reflected in our financial statements, which will be affected by non-cash items. As a result, we may make cash distributions, if permitted by our credit agreement, during periods when we record losses for financial accounting purposes and may not make cash distributions during periods when we record net earnings for financial accounting purposes.

Our debt levels under our credit agreement may limit our ability to make distributions and our flexibility in obtaining additional financing and in pursuing other business opportunities.

As of December 31, 2012, we had approximately $211.3 million in outstanding indebtedness under our credit facility. Our level of debt under the credit facility could have important consequences for us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;
- we will need a substantial portion of our cash flow to make principal and interest payments on our debt, reducing the funds that would otherwise be available for operations, future business opportunities and distributions to unitholders;
- our debt level will make us more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- our debt level may limit our flexibility in responding to changing business and economic conditions.

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. Our ability to service debt under our credit facility also will depend on market interest rates, since the interest rates applicable to our borrowings will fluctuate with the eurodollar rate or the prime rate. If our operating results are not sufficient to service our current or future indebtedness, we will be forced to take actions such as reducing distributions, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets, restructuring or refinancing our debt, or seeking additional equity capital. We may not be able to effect any of these actions on satisfactory terms, or at all.

We may not be able to raise sufficient capital to grow our business.

As of March 7, 2013, we had an aggregate unused credit availability under our revolving credit facility of approximately $62.5 million and cash on hand of approximately $3.7 million. Our ability to access capital markets may be limited due to uncertainty of our future cash flows, litigation and other contingencies. In addition, we may have difficulty obtaining a credit rating or any credit rating that we do obtain may be lower than it otherwise would be due to these uncertainties. The lack of a credit rating or a low credit rating may also adversely impact our ability to access capital markets.

If we fail to raise additional capital or an event of default exists under our credit agreement, we may be forced to sell assets or take other action that could have a material adverse effect on our business, the price of our units and our results of operations. In addition, if we are unable to access the capital markets for acquisitions or expansion projects, it may have a material adverse effect on our business, cash flows, ability to make distributions to our unitholders, the price of our units, our results of operations and ability to conduct our business.

If we borrow funds to make any permitted quarterly distributions, our ability to pursue acquisitions and other business opportunities may be limited and our operations may be materially and adversely affected.

Available cash for the purpose of making distributions to unitholders includes working capital borrowings. If we borrow funds to pay one or more quarterly distributions, such amounts will incur interest and must be repaid in accordance with the terms of our credit facility. In addition, any amounts borrowed for permitted distributions to our unitholders will reduce the funds available to us for other purposes under our credit facility, including amounts available for use in connection with acquisitions and other business opportunities. If we are unable to pursue our growth strategy due to our limited ability to borrow funds, our operations may be materially and adversely affected.

We are indirectly exposed to commodity price volatility.

Our operations have minimal direct exposure to changes in crude oil and asphalt cement prices. However, the volumes of crude oil and asphalt cement we gather, transport or store are indirectly affected by commodity prices because many of our customers have direct commodity price exposure. If our customers are negatively impacted by commodity price volatility, they may, among other things, decrease the amount of services that we provide to them. The prices of crude oil and asphalt are inherently volatile, and we expect this volatility to continue. Any significant reduction in the amount of services we provide to our customers would have a material adverse effect on our results of operations and cash flows.

Our revenues from third-party customers are generated under contracts that must be renegotiated periodically and that allow the customer to reduce or suspend performance in some circumstances, which could cause our revenues from those contracts to decline and reduce our ability to make distributions to our unitholders.

Some of our contract-based revenues from customers are generated under contracts with terms which allow the customer to reduce or suspend performance under the contract in specified circumstances, such as the occurrence of a catastrophic event to our or the customer's operations. The occurrence of an event which results in a material reduction or suspension of our customer's performance could have a material adverse effect on our financial condition, results of operations and cash flows.

Many of our contracts with customers for producer field services have terms of one year or less. As these contracts expire, they must be extended and renegotiated or replaced. We may not be able to extend, renegotiate or replace these contracts when they expire, and the terms of any renegotiated contracts may not be as favorable as the contracts they replace. In particular, our ability to extend or replace contracts could be harmed by numerous competitive factors, such as those described above under "Item 1. Business - Competition." We face intense competition in our gathering, transportation, terminalling and storage activities. Competition from other providers of crude oil gathering, transportation, terminalling and storage services that are able to supply our customers with those services at a lower price could reduce our ability to make distributions to our unitholders. Additionally, we may incur substantial costs if modifications to our terminals are required in order to attract substitute customers or provide alternative services. If we cannot successfully renew significant contracts or must renew them on less favorable terms, or if we incur substantial costs in modifying our terminals, our revenues from these arrangements could decline which could have a material adverse effect on our financial condition, results of operations and cash flows.

Certain of our asphalt services contracts have short terms, and certain leases relating to our asphalt operations may be terminated upon short notice.

As of December 31, 2012, we had leases and storage agreements with third party customers relating to 43 of our 44 asphalt facilities. The majority of the leases and storage agreements related to these facilities have terms that expire between the end of

2016 and the end of 2018. We may not be able to renew or extend our existing contracts or enter into new leases or storage agreements when such contracts expire. In addition, certain key customers account for a portion of our asphalt services revenues, the loss of which could result in a decrease in revenues from our asphalt operations. A significant decrease in the revenues we receive from our asphalt operations could result in violations of covenants under our credit facility and could have a material adverse effect on our business, cash flows, ability to make distributions to our unitholders, the price of our units, our results of operations and ability to conduct our business.

In addition, certain of our asphalt facilities are located on land that we lease. Some of these leases may be terminated by the lessor with as short as thirty days' notice. We also have not yet received consent from certain of the lessors to sublease such facilities, which may result in a default under such lease or invalidate the subleases. If such leases were terminated, it could have a material adverse effect on our ability to provide asphalt services, which could have a material adverse effect on our business, cash flows, ability to make distributions to our unitholders, the price of our units, our results of operations and ability to conduct our business. In addition, in certain instances, we have not entered into new leases with a lessor although we continue to use prior leases and make payments to the lessor and are in the process of negotiating new leases. If it were determined that we did not have rights under these leases, it could have a material adverse effect on our ability to conduct our asphalt operations and on our financial condition, results of operations and cash flows.

We are not fully insured against all risks incident to our business and could incur substantial liabilities as a result.

We may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of changing market conditions, premiums and deductibles for certain of our insurance policies may increase substantially in the future. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our business, cash flows, ability to make distributions to our unitholders, the price of our units, our results of operations and ability to conduct our business.

A significant decrease in demand for crude oil and/or finished asphalt products in the areas served by our storage facilities and pipelines could reduce our ability to make distributions to our unitholders.

A sustained decrease in demand for crude oil and/or finished asphalt products in the areas served by our storage facilities and pipelines could significantly reduce our revenues and, therefore, reduce our ability to make or increase distributions to our unitholders. Factors that could lead to a decrease in market demand for crude oil and finished asphalt products include:

- lower demand by consumers for refined products, including finished asphalt products, as a result of recession or other adverse economic conditions or due to high prices caused by an increase in the market price of crude oil or higher fuel taxes or other governmental or regulatory actions that increase, directly or indirectly, the cost of gasolines or other refined products;
- a shift by consumers to more fuel-efficient or alternative fuel vehicles or an increase in fuel economy of vehicles, whether as a result of technological advances by manufacturers, governmental or regulatory actions or otherwise; and
- fluctuations in demand for crude oil, such as those caused by refinery downtime or shutdowns.

Certain of our field and pipeline operating costs and expenses are fixed and do not vary with the volumes we gather and transport. These costs and expenses may not decrease ratably or at all should we experience a reduction in our volumes gathered or transmitted by our gathering and transportation operations. As a result, we may experience declines in our margin and profitability if our volumes decrease.

A material decrease in the production of crude oil from the oil fields served by our pipelines could materially reduce our ability to make distributions to our unitholders.

The throughput on our crude oil pipelines depends on the availability of attractively priced crude oil produced from the oil fields served by such pipelines or through connections with pipelines owned by third parties. Crude oil production may decline for a number of reasons, including natural declines due to depleting wells, a material decrease in the price of crude oil, or the inability of producers to obtain necessary drilling or other permits from applicable governmental authorities. If we are unable to replace volumes lost due to a temporary or permanent material decrease in production from the oil fields served by our crude oil pipelines, our throughput could decline, reducing our revenue and cash flow and adversely affecting our financial condition and results of operations. In addition, it is difficult to attract producers to a new gathering system if the producer is already connected to an existing system. As a result, third-party shippers on our pipeline systems may experience difficulty acquiring crude oil at the wellhead in areas where there are existing relationships between producers and other gatherers and purchasers of crude oil.

A material decrease in the production of liquid asphalt cement could materially reduce our ability to make distributions to our unitholders.

The throughput at our asphalt facilities depends on the availability of attractively priced liquid asphalt cement produced from the various liquid asphalt cement producing refineries. Liquid asphalt cement production may decline for a number of reasons, including refiners processing more light, sweet crude oil or refiners installing coker units that further refine heavy residual fuel oil bottoms such as liquid asphalt cement. If our customers are unable to replace volumes lost due to a temporary or permanent material decrease in production from the suppliers of liquid asphalt cement, our throughput could decline, reducing our revenue and cash flow and adversely affecting our financial condition and results of operations.

We face intense competition in our gathering, transportation, terminalling and storage activities. Competition from other providers of crude oil gathering, transportation, terminalling and storage services that are able to supply our customers with those services at a lower price could reduce our ability to make distributions to our unitholders.

We are subject to competition from other crude oil gathering, transportation, terminalling and storage operations that may be able to supply our customers with the same or comparable services on a more competitive basis. We compete with national, regional and local gathering, storage, terminalling and pipeline companies, including the major integrated oil companies, of widely varying sizes, financial resources and experience. Some of these competitors are substantially larger than us, have greater financial resources, and control substantially greater storage capacity than we do. With respect to our gathering and transportation services, these competitors include Enterprise Products Partners L.P., Plains All American Pipeline, L.P., ConocoPhillips and Sunoco Logistics Partners L.P., among others. With respect to our storage and terminalling services, these competitors include Magellan Midstream Partners, L.P., Enbridge Energy Partners, L.P., Enterprise Products Partners L.P. and Plains All American Pipeline, L.P. Several of our competitors conduct portions of their operations through publicly traded partnerships with structures similar to ours, including Plains All American Pipeline, L.P., Enterprise Products Partners L.P., Sunoco Logistics Partners L.P. and Enbridge Energy Partners, L.P. Our ability to compete could be harmed by numerous factors, including:

- price competition;
- the perception that another company can provide better service; and
- the availability of alternative supply points, or supply points located closer to the operations of our customers.

In addition, each of Charlesbank and Vitol owns midstream assets and may engage in competition with us. If we are unable to compete with services offered by other midstream enterprises, it could have a material adverse effect on our financial condition, results of operations and cash flows. See "- Risks Inherent in an Investment in Us - Vitol and Charlesbank may compete with us, which could adversely affect our existing business and limit our ability to acquire additional assets or businesses."

Some of our pipeline systems are dependent upon interconnections with other crude oil pipelines to reach end markets.

Some of our pipeline systems are dependent upon their interconnections with other crude oil pipelines to reach end markets. Reduced throughput on these interconnecting pipelines as a result of testing, line repair, reduced operating pressures or other causes could result in reduced throughput on our pipeline systems that would adversely affect our revenue, cash flow and results of operations.

If we are unable to make acquisitions on economically acceptable terms, our future growth may be limited.

Our ability to grow in the future will depend, in part, on our ability to make acquisitions that result in an increase in the cash generated per unit from operations. Vitol and Charlesbank have indicated that they intend to use us as a growth vehicle to pursue the acquisition and expansion of midstream energy businesses and assets. Vitol and Charlesbank have formed Development Company and have informed us it is intended to be focused on developing projects that we may later have the opportunity to acquire. Vitol and Charlesbank own Development Company and we have no interest in this new entity. We cannot say with any certainty if Development Company will develop any projects or, if it does, which, if any, of these future acquisition opportunities may be made available to us by Development Company or if we will choose to pursue any such opportunity. In addition, indentifying projects for and developing projects within Development Company may result in the diversion of management's and employees' attention from operating our assets and other business concerns of our partnership.

In addition to any projects acquired and developed by Development Company, we may also make acquisitions directly from third parties. If we are unable to make accretive acquisitions, either because we are (1) unable to establish the terms of Development Company or acquire projects from Development Company when they are available, (2) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them, (3) unable to obtain financing for these acquisitions on economically acceptable terms or (4) outbid by competitors, then our future growth and ability to increase distributions will be limited. Furthermore, even if we do make acquisitions that we believe will be accretive, these acquisitions may nevertheless result in a decrease in the cash generated from operations per unit.

Any acquisition involves potential risks, including, among other things:

- mistaken assumptions about volumes, revenues and costs, including synergies;
- an inability to integrate successfully the businesses we acquire;
- an inability to hire, train or retain qualified personnel to manage and operate our business and assets;
- the assumption of unknown liabilities;
- limitations on rights to indemnity from the seller;
- mistaken assumptions about the overall costs of equity or debt;
- the diversion of management’s and employees’ attention from other business concerns;
- unforeseen difficulties operating in new product areas or new geographic areas; and
- customer or key employee losses at the acquired businesses.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and our unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

If we acquire assets that are distinct and separate from our existing terminalling, storage, gathering and transportation operations, it could subject us to additional business and operating risks.

We may acquire midstream assets that have operations in new and distinct lines of business from our crude oil or our liquid asphalt cement operations. Integration of a new business is a complex, costly and time-consuming process. Failure to timely and successfully integrate acquired entities’ lines of business with our existing operations may have a material adverse effect on our business, financial condition, results of operations and cash flows. The difficulties of integrating a new business with our existing operations include, among other things:

- operating distinct businesses that require different operating strategies and different managerial expertise;
- the necessity of coordinating organizations, systems and facilities in different locations;
- integrating personnel with diverse business backgrounds and organizational cultures; and
- consolidating corporate and administrative functions.

In addition, the diversion of our attention and any delays or difficulties encountered in connection with the integration of a new business, such as unanticipated liabilities or costs, could harm our existing business, results of operations, financial conditions and prospects. Furthermore, new lines of business will subject us to additional business and operating risks. For example, we may in the future determine to acquire businesses that are subject to significant risks due to fluctuations in commodity prices. These new business and operating risks could have a material adverse effect on our financial condition, results of operations and cash flows.

Expanding our business by constructing new assets subjects us to risks that projects may not be completed on schedule and that the costs associated with projects may exceed our expectations, which could cause our cash available for distribution to our unitholders to be less than anticipated.

The construction of additions or modifications to our existing assets, and the construction of new assets, involves numerous regulatory, environmental, political, legal and operational uncertainties and requires the expenditure of significant amounts of capital. If we undertake these types of projects, they may not be completed on schedule or at all or at the budgeted cost. In addition, our revenues may not increase immediately upon the expenditure of funds on a particular project. Moreover, we may construct facilities to capture anticipated future growth in demand in a market in which such growth does not materialize.

We may incur significant costs and liabilities as a result of pipeline integrity management program testing and any necessary pipeline repair, or preventative or remedial measures, which could have a material adverse effect on our results of operations.

The DOT has adopted regulations requiring pipeline operators to develop integrity management programs for transportation pipelines located where a leak or rupture could do the most harm in "high consequence areas," including high population areas, areas that are sources of drinking water or ecological resource areas that are unusually sensitive to environmental damage from a pipeline release and commercially navigable waterways, unless the operator effectively demonstrates by risk assessment that the pipeline could not affect the area. The regulations require operators of covered pipelines to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize threats to pipeline segments that could impact a high consequence area;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

Effective July 2008, the DOT broadened the scope of coverage of its existing pipeline safety standards, including its integrity management programs, to include certain rural onshore hazardous liquid and low-stress pipeline systems found near "unusually sensitive areas," including non-populated areas requiring extra protection because of the presence of sole source drinking water resources, endangered species or other ecological resources. Also, in December 2006,PIPES was enacted. PIPES reauthorizes and amends the DOT's pipeline safety programs and includes a provision eliminating the regulatory exemption for hazardous liquid pipelines operated at low stress. The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, enacted in January 2012, requires the DOT to study and report on the expansion of integrity management requirements, the sufficiency of existing gathering line regulations to ensure safety and the feasibility of leak detection systems for hazardous liquid pipelines. Adoption of new or more stringent pipeline safety regulations affecting our interstate gathering or low-stress pipelines could result in more rigorous and costly integrity management planning requirements being imposed on those lines, which could have a material adverse effect on our results of operations. Please read "Item 1. Business-Regulation-Pipeline Safety" for more information.

We may be subject to significant costs related to environmental investigations and/or remediation activities at our asphalt facilities.

We acquired our asphalt assets from SemCorp in 2008 and 2009. The majority of these assets were previously acquired by SemCorp from Koch Industries, Inc. (together with its subsidiaries, "Koch") in 2005. Koch retained certain liabilities, including certain environmental liabilities, when it sold the assets to SemCorp. Since 2005, Koch has been conducting environmental investigation and/or remediation activities at certain of our asphalt facilities in connection with these retained environmental liabilities. Koch has alleged that it does not have continued responsibility for these retained environmental liabilities at one of our asphalt facilities because of SemCorp's bankruptcy. Because Koch has conducted all environmental investigation and/or remediation activities at this site, we do not know the extent of any environmental issues and we are unable to estimate the costs or timing of any investigation and/or remediation activities, which may be material. On February 13, 2013, we filed suit against Koch, seeking a declaration that Koch is responsible for any assessment and cleanup costs related to any environmental liabilities. To date, Koch has not filed an answer to the complaint. In addition, Koch may make similar allegations regarding retained environmental liabilities at other of our asphalt facilities. Although we intend to defend any such allegations, if we are found to be liable for such environmental liabilities, it could have a material adverse effect on our business, cash flows, ability to make distributions to our unitholders, the price of our units, our results of operations and ability to conduct our business.

Our operations are subject to environmental and worker safety laws and regulations that may expose us to significant costs and liabilities. Failure to comply with these laws and regulations could adversely affect our ability to make distributions to our unitholders.

Our midstream crude oil gathering, transportation, terminalling and storage operations and our asphalt terminalling and storage assets are subject to stringent federal, state and local laws and regulations relating to the protection of the environment. Various governmental authorities, including the EPA, have the power to enforce compliance with these laws and regulations and the permits issued under them, and violators are subject to administrative, civil and criminal penalties, including civil fines, injunctions or both. Joint and several strict liability may be incurred without regard to fault or the legality of the original conduct under CERCLA, RCRA and analogous state laws for the remediation of contaminated areas. Private parties, including the owners of properties located near our terminalling and storage facilities or through which our pipeline systems pass, also may have the right to pursue legal actions to enforce compliance, as well as seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. Moreover, new stricter laws, regulations or enforcement policies could be implemented that significantly increase our compliance costs and the cost of any remediation that may become necessary, some of which may be material.

In performing midstream operations and asphalt services, we incur environmental costs and liabilities in connection with the handling of hydrocarbons and solid wastes. We currently own, operate or lease properties that for many years have been used for midstream activities, including properties in and around the Cushing Interchange, and with respect to our asphalt assets, for asphalt activities. Activities by us or prior owners, lessees or users of these properties over whom we had no control may have resulted in the spill or release of hydrocarbons or solid wastes on or under them. Additionally, some sites we own or operate are located near current or former storage, terminal and pipeline operations, and there is a risk that contamination has migrated from those sites to ours. Increasingly strict environmental laws, regulations and enforcement policies as well as claims for damages and other similar developments could result in significant costs and liabilities, and our ability to make distributions to our unitholders could suffer as a result. Please see “Item 1-Business-Regulation” for more information.

In addition, the workplaces associated with the storage facilities and pipelines we operate are subject to OSHA requirements and comparable state statutes that regulate the protection of the health and safety of workers. The OSHA hazard communication standard requires that we maintain information about hazardous materials used or produced in our operations and that we provide this information to employees, state and local government authorities, and local residents. Failure to comply with OSHA requirements, including general industry standards, recordkeeping requirements and monitoring of occupational exposure to regulated substances, could subject us to fines or significant compliance costs and have a material adverse effect on our financial condition, results of operations and cash flows.

Adoption of legislation and regulatory measures targeting greenhouse gas (GHG) emissions could affect our operations, expose us to significant costs and liabilities, and reduce demand for the products we transport.

The crude oil and petroleum-based product business is a direct source of certain GHG emissions, namely carbon dioxide and methane, and future restrictions on such emissions could impact our future operations. Federal legislation requiring GHG controls is under consideration and may be enacted. Moreover, EPA has promulgated a series of rulemakings and other actions intended to result in the regulation of GHGs as pollutants under the CAA. In April 2010, EPA promulgated final motor vehicle GHG emission standards, which apply to vehicle model years 2012 - 2016. EPA has taken the position that the motor vehicle GHG emission standards triggered CAA permitting requirements for certain affected stationary sources of GHG emissions beginning on January 2, 2011. In May 2010, EPA finalized the Prevention of Significant Deterioration and Title V GHG Tailoring Rule, which phases in federal new source review and Title V permitting requirements for certain affected stationary sources of GHG emissions, beginning January 2, 2011. These EPA rulemakings could affect our operations by effectively reducing demand for motor fuels from crude oil and could affect our ability to obtain air permits for new or modified facilities. Moreover, in 2009, the EPA issued a rule that establishes comprehensive requirements for monitoring and reporting of GHG emissions on an annual basis by operators of certain stationary sources in the U.S. emitting more than established annual thresholds of carbon dioxide-equivalent GHG emissions. Monitoring obligations began in 2010 and reporting obligations began in March 2011. Some of our facilities include natural gas-fired combustion units that may become subject to the rule. These facilities will be required to annually calculate their GHG emissions to determine whether they trigger reporting and monitoring requirements. To date, none of our facilities have exceeded the thresholds established for reporting or monitoring requirements. Although this rule does not control GHG emission levels from any facilities, it will still cause us to incur monitoring and reporting costs relating to GHG emissions. Furthermore, the scope of the rule was expanded for 2011 to cover additional petroleum and natural gas production, processing, and transmission sources (“Subpart W”) that were not previously covered by the rule. This expansion in scope may impact the crude oil industry and, as a result, affect our business. We continue to monitor and review these regulations to determine future impacts, including potential reporting requirements. Legislation and regulations relating to control or reporting of GHG emissions are also in various stages of discussions or implementation in many of the states in which we operate.

Passage of climate change legislation or other federal or state legislative or regulatory initiatives that regulate or restrict GHG emissions in areas in which we conduct business or that have the effect of requiring or encouraging reduced consumption or production of crude oil and petroleum-based products could potentially

- adversely affect the demand for our products and services;
- affect our operations and ability to obtain air permits for new or modified facilities;
- increase the costs to operate and maintain our facilities;

- increase the costs of our business by requiring us to acquire allowances to authorize our GHG emissions (e.g., for natural gas-fired combustion units);
- increase the costs of our business by requiring us to pay any taxes related to our GHG emissions and/or administer and manage a GHG emissions program; and
- increase the cost or availability of goods and services as a result of impacts on entities that provide goods and services to us.

In addition to potential impacts on our business directly or indirectly resulting from climate-change legislation or regulations, our business also could be negatively affected by climate-change related physical changes or changes in weather patterns. A loss of coastline in the vicinity of our facilities or an increase in severe weather patterns could result in damages to or loss of our physical assets, impact our ability to conduct operations and/or result in a disruption of our customer's operations. These kinds of physical changes could also affect entities that provide goods and services to us and indirectly have an adverse affect on our business as a result of increases in costs or availability of goods and services. Changes of this nature could have a material adverse impact on our business.

Please read "Item 1. Business-Environmental, Health and Safety Risks-Climate" for more information.

Our business involves many hazards and operational risks, including adverse weather conditions, which could cause us to incur substantial liabilities.

Our operations are subject to the many hazards inherent in the transportation and storage of crude oil and the storage and processing of liquid asphalt cement, including:

- explosions, fires, accidents, including road and highway accidents involving our tanker trucks;
- extreme weather conditions, such as hurricanes which are common in the Gulf Coast and tornadoes and flooding which are common in the Midwest;
- damage to our pipelines, storage tanks, terminals and related equipment;
- leaks or releases of crude oil into the environment; and
- acts of terrorism or vandalism.

If any of these events were to occur, we could suffer substantial losses because of personal injury or loss of life, severe damage to and destruction of property and equipment, and pollution or other environmental damage resulting in curtailment or suspension of our related operations. In addition, mechanical malfunctions, faulty measurement or other errors may result in significant costs or lost revenues.

We do not own all of the land on which our pipelines and facilities are located, which could disrupt our operations.

We do not own all of the land on which our pipelines and crude oil and asphalt facilities have been constructed, and we are therefore subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if we do not have valid rights-of-way or if such rights-of-way or any material real property leases lapse or terminate. We obtain the rights to construct and operate our pipelines and some of our crude oil and asphalt facilities on land owned by third parties and governmental agencies for a specific period of time. Our loss of these rights, through our inability to renew leases, right-of-way contracts or otherwise, could have a material adverse effect on our business, results of operations, financial condition, cash flows and our ability to make cash distributions to our unitholders. In addition, we are in the process of obtaining consents from the lessors for certain leased property that was transferred to us as part of the acquisition of our asphalt assets. If any consent is denied, it could have a material adverse effect on our business, results of operations, financial condition, cash flows and our ability to make cash distributions to our unitholders.

We could experience increased severity or frequency of accidents and other claims.

Potential liability associated with accidents in the trucking industry is severe and occurrences are unpredictable. A material increase in the frequency or severity of accidents or workers' compensation claims or the unfavorable development of existing claims could be expected to materially adversely affect our results of operations. In the event that accidents occur, we may be unable to obtain desired contractual indemnities, and our insurance may provide inadequate in certain cases. The occurrence of an event not fully insured or indemnified against, or the failure or inability of a customer or insurer to meet its indemnification or insurance obligations, could result in substantial losses.

Changes in trucking regulations may increase our costs and negatively impact our results of operations.

Our trucking services are subject to regulation as a motor carrier by the DOT and by various state agencies, whose regulations include certain permit requirements of state highway and safety authorities. These regulatory authorities exercise broad powers over our trucking operations, generally governing such matters as the authorization to engage in motor carrier operations, safety, equipment testing and specifications and insurance requirements. There are additional regulations specifically relating to the trucking industry, including testing and specification of equipment and product handling requirements. The trucking industry is subject to possible regulatory and legislative changes that may impact our operations and affect the economics of the industry by requiring changes in operating practices or by changing the demand for or the cost of providing truckload services. Some of these possible changes include increasingly stringent fuel emission limits, changes in the regulations that govern the amount of time a driver may drive or work in any specific period, limits on vehicle weight and size and other matters, including safety requirements.

Risks Inherent in an Investment in Us

Vitol and Charlesbank control our General Partner, which has sole responsibility for conducting our business and managing our operations. Our General Partner has conflicts of interest with us and limited fiduciary duties, which may permit it to favor its own interests to the detriment of our unitholders.

Vitol and Charlesbank own and control our General Partner. Some of our General Partner's directors are directors and officers of Vitol or Charlesbank. Therefore, conflicts of interest may arise between our General Partner, on the one hand, and us and our unitholders, on the other hand. In resolving those conflicts of interest, our General Partner may favor its own interests and the interests of its affiliates over the interests of our unitholders. Although the conflicts committee of the board of directors of our General Partner (the "Board") may review such conflicts of interest, the Board is not required to submit such matters to the conflicts committee. These conflicts include, among others, the following situations:

- neither our partnership agreement nor any other agreement requires our General Partner, Vitol or Charlesbank to pursue a business strategy that favors us. Such persons may make these decisions in their best interest, which may be contrary to our interests;
- our General Partner is allowed to take into account the interests of parties other than us, such as Vitol, Charlesbank and their affiliates, in resolving conflicts of interest;
- if we do not have sufficient available cash from operating surplus, our General Partner could cause us to use cash from non-operating sources, such as asset sales, issuances of securities and borrowings, to pay distributions, which means that we could make distributions that deteriorate our capital base and that our General Partner could receive distributions on its incentive distribution rights to which it would not otherwise be entitled if we did not have sufficient available cash from operating surplus to make such distributions;
- Vitol and Charlesbank are holders of our Preferred Units and may favor their interests in actions relating to such units, including causing us to make distributions on such units even if no distributions are made on the common units;
- Vitol and Charlesbank may compete with us, including with respect to future acquisition opportunities (either through Development Company or otherwise);
- Vitol and Charlesbank may favor their own interests in proposing the terms of any acquisitions we make directly from them or from Development Company, and such terms may not be as favorable as those we could receive from an unrelated third party;
- our General Partner has limited its liability and reduced its fiduciary duties and has also restricted the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;
- our General Partner determines the amount and timing of asset purchases and sales, borrowings, issuance of additional partnership securities and reserves, each of which can affect the amount of cash that is distributed to unitholders;

- our General Partner determines the amount and timing of any capital expenditures and whether a capital expenditure is a maintenance capital expenditure, which reduces operating surplus, or an expansion capital expenditure, which does not reduce operating surplus. This determination can affect the amount of cash that is distributed to our unitholders;
- our General Partner may make a determination to receive a quantity of our Class B units in exchange for resetting the target distribution levels related to its incentive distribution rights without the approval of the conflicts committee of our General Partner or our unitholders;

- our General Partner determines which costs incurred by it and its affiliates 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 to us or entering into additional contractual arrangements with any of these entities on our behalf;
- our General Partner intends to limit its liability regarding our contractual and other obligations and, in some circumstances, is entitled to be indemnified by us;
- our General Partner may exercise its limited right to call and purchase common units if it and its affiliates own more than 80% of the common units;
- our General Partner controls the enforcement of obligations owed to us by our General Partner and its affiliates; and
- our General Partner decides whether to retain separate counsel, accountants or others to perform services for us.

Our partnership agreement limits our General Partner's fiduciary duties to holders of our units and restricts the remedies available to holders of our units for actions taken by our General Partner that might otherwise constitute breaches of fiduciary duty.

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

- permits our General Partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our General Partner. This entitles our General Partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include the exercise of its right to receive a quantity of our Class B units in exchange for resetting the target distribution levels related to its incentive distribution rights, the exercise of its limited call right, the exercise of its rights to transfer or vote the units it owns, the exercise of its registration rights and its determination whether or not to consent to any merger or consolidation of the partnership or amendment to the partnership agreement;
- provides that our General Partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as it acted in good faith, meaning it believed the decision was in the best interests of our partnership;
- generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the conflicts committee of the Board acting in good faith and not involving a vote of unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or must be "fair and reasonable" to us, as determined by our General Partner in good faith. In determining whether a transaction or resolution is "fair and reasonable," our General Partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us;
- 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 any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our General Partner or its officers and directors acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and
- provides that in resolving conflicts of interest, it will be presumed that in making its decision our General Partner acted in good faith, and in any proceeding brought by or on behalf of any limited partner or us, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

By purchasing a common unit, a common unitholder will become bound by the provisions in the partnership agreement, including the provisions discussed above.

Vitol and Charlesbank may compete with us, which could adversely affect our existing business and limit our ability to acquire additional assets or businesses.

Neither our partnership agreement nor any other agreement with Vitol or Charlesbank prohibits Vitol or Charlesbank from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, Vitol or Charlesbank may acquire (either directly or through Development Company), construct or dispose of additional midstream or other assets in the future, without any obligation to offer us the opportunity to purchase or construct any of those assets. Vitol is a large, international organization and Charlesbank is a middle-market private equity investment firm. Each of Vitol and Charlesbank has significantly greater resources and experience than we have, which factors may make it more difficult for us to compete with these entities with respect to commercial activities as well as for acquisition candidates. As a result, competition from these entities could adversely impact our results of operations and cash available for distribution.

Cost reimbursements due to our General Partner and its affiliates for services provided, which are determined by our General Partner, may be substantial and will reduce our cash available for distribution to our unitholders.

Pursuant to our partnership agreement, our General Partner and its affiliates, including Vitol and Charlesbank, are entitled to receive reimbursement for the payment of expenses related to our operations and for the provision of various general and administrative services for our benefit. Payments for these services may be substantial and reduce the amount of cash available for distribution to unitholders. In addition, under Delaware partnership law, our General Partner 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. To the extent our General Partner incurs obligations on our behalf, we are obligated under our partnership agreement to reimburse or indemnify our General Partner. If we are unable or unwilling to reimburse or indemnify our General Partner, our General Partner may take actions to cause us to make payments of these obligations and liabilities. Any such payments would reduce the amount of cash otherwise available for distribution to our unitholders.

Holders of our Preferred Units and common units have limited voting rights and are not entitled to elect our General Partner or its directors.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders did not elect our General Partner or the Board and have no right to elect our General Partner or the Board on an annual or other continuing basis. The Board is chosen by Vitol and Charlesbank. Furthermore, if the unitholders are dissatisfied with the performance of our General Partner, they have little ability to remove our General Partner. Amendments to our partnership agreement may be proposed only by or with the consent of our General Partner. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Control of our General Partner may be transferred to a third party without unitholder consent.

Our General Partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, our partnership agreement does not restrict the ability of Vitol and Charlesbank, the owners of our General Partner, from transferring all or a portion of their ownership interest in our General Partner to a third party. The new owner of our General Partner would then be in a position to replace the Board and officers of our General Partner with its own choices and thereby influence the decisions made by the Board and officers.

We may issue additional units without approval of our unitholders, which would dilute our unitholders' ownership interests.

Except in the case of (1) the issuance on or before June 30, 2015 of units senior to the common units or (2) the issuance of units that rank equal to or senior to the Preferred Units, our partnership agreement does not limit the number or price of additional limited partner interests that we may issue at any time without the approval of our unitholders. In addition, because we are a limited partnership, we will not be subject to the shareholder approval requirements relating to the issuance of securities (other than in connection with the establishment or material amendment of a stock option or purchase plan or the making or material amendment of any other equity compensation arrangement) contained in Nasdaq Marketplace Rule 5635. The issuance by us 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 each unit may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

Our partnership agreement restricts the voting rights of unitholders, other than our General Partner and its affiliates, including Vitol and Charlesbank, owning 20% or more of any class of our partnership securities.

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

Even if holders of our Preferred Units or common units are dissatisfied, they cannot initially remove our General Partner without its consent.

Our unitholders will be unable initially to remove our General Partner without its consent because our General Partner and its affiliates own a sufficient number of units to be able to prevent its removal. The vote of the holders of at least 66 2/3% of all outstanding units voting together as a single class is required to remove the General Partner. As of December 31, 2012, Vitol and Charlesbank collectively owned approximately 34.6% of our aggregate outstanding Preferred Units and common units.

Affiliates of our General Partner may sell units in the public markets, which sales could have an adverse impact on the trading price of the units.

As of March 7, 2013, the executive officers and directors of our General Partner beneficially own an aggregate of 124,897 common units and 30,995 Preferred Units and Vitol and Charlesbank collectively own 18,312,968 Preferred Units. The sale of these units in the public markets could have an adverse impact on the price of the units or on any trading market that may develop.

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

If at any time our General Partner and its affiliates own more than 80% of any class of units then outstanding, 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 such class of units held by unaffiliated persons at a price not less than their then-current market price. As a result, our unitholders may be required to sell their units at an undesirable time or price and may not receive any return on their investment. Our unitholders also may incur a tax liability upon a sale of their units. As of December 31, 2012, Vitol and Charlesbank collectively owned 60.7% of our outstanding Preferred Units.

Units held by persons who are not Eligible Holders will be subject to the possibility of redemption.

Our General Partner has the right under our partnership agreement to institute procedures, by giving notice to each of our unitholders, that would require transferees of units and, upon the request of our General Partner, existing holders of our units to certify that they are Eligible Holders. The purpose of these certification procedures would be to enable us to establish a federal income tax expense as a component of the pipeline’s cost of service for ratemaking purposes under current FERC policy applicable to entities that pass through their taxable income to their owners. Eligible Holders are individuals or entities subject to United States federal income taxation on the income generated by us or entities not subject to United States federal income taxation on the income generated by us, so long as all of the entity’s owners are subject to such taxation. If these tax certification procedures are implemented, we will have the right to redeem the units held by persons who are not Eligible Holders at the lesser of the holder’s purchase price and the then-current market price of the units. The redemption price would be paid in cash or by delivery of a promissory note, as determined by our General Partner.

Holders of our Preferred Units have a distribution preference and a liquidation preference, which may adversely impact the value of our common units.

The Preferred Units rank prior to our common units as to both distributions of available cash and distributions upon liquidation. Holders of our Preferred Units are entitled to quarterly distributions of $0.17875 per unit per quarter (or $0.7150 per unit on an annual basis). If we fail to pay in full any distribution on our Preferred Units, the amount of such unpaid distribution will accrue and accumulate from the last day of the quarter for which such distribution is due until paid in full. If we are liquidated, we may not have sufficient funds remaining after payment of amounts to our creditors and to holders of our Preferred Units to make any distribution to holders of our common units.

The conversion rate applicable to the Preferred Units will not be adjusted for all events that may be dilutive.

The number of our common units issuable upon conversion of the Preferred Units is subject to adjustment only for subdivisions, splits or certain combinations of our common units. The number of common units issuable upon conversion is not subject to adjustment for other events, such as employee option grants, offerings of our common units for cash or in connection with acquisitions or other transactions that may increase the number of outstanding common units and dilute the ownership of existing common unitholders. The terms of the Preferred Units do not restrict our ability to offer common units in the future or to engage in other transactions that could dilute our common units.

We have rights to require our preferred unitholders to convert their Preferred Units into common units, and we may exercise this mandatory conversion right at an undesirable time.

We have the right in certain circumstances, including if a certain number of Preferred Units are converted to common units or if certain distribution levels or trading price levels on the common units are reached, to force the conversion of all outstanding Preferred Units to common units. Vitol and Charlesbank, the owners of our General Partner, own enough Preferred Units such that if they converted all of them to common units, we could then force all remaining outstanding Preferred Units to convert to common units. As a result, our preferred unitholders may be required to convert their Preferred Units at an undesirable time and may not receive their expected return on investment.

Holders of the Preferred Units will not have rights to distributions as holders of common units until they acquire our common units.

Until our preferred unitholders acquire common units upon conversion of the Preferred Units, such preferred unitholders will have no rights with respect to distributions on our common units. Upon conversion, our preferred unitholders will be entitled to exercise the rights of a holder of our common units only as to matters for which the record date occurs after the date on which such Preferred Units were converted to our common units.

The Preferred Units are limited partner interests in our partnership and therefore are subordinate to any indebtedness.

The Preferred Units are limited partner interests in our partnership and do not constitute indebtedness. As such, the Preferred Units will rank junior to all indebtedness and other non-equity claims on our partnership with respect to assets available to satisfy claims on our partnership, including in a liquidation of our partnership.

Market interest rates may affect the value of our units.

One of the factors that will influence the price of our units will be the distribution yield on our units relative to market interest rates. An increase in market interest rates could cause the market price of the units to go down. The trading price of the units will also depend on many other factors, which may change from time to time, including:

- the market for similar securities;
- government action or regulation;
- general economic conditions or conditions in the financial markets; and
- our financial condition, performance and prospects.

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

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

Our unitholders could be liable for our obligations as if they were a general partner if:

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

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

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 and 17-804 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable for the obligations of the assignor to make contributions to the partnership that are known to the substituted limited partner at the time it became a limited partner and for unknown obligations if the liabilities could be determined from the partnership agreement. Liabilities to partners on account of their partnership interests and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

Tax Risks to Unitholders

Our common unitholders have been and will be required to pay taxes on their share of our taxable income even if they have not or do not receive any cash distributions from us.

Because our unitholders are treated as partners to whom we allocate taxable income which could be different in amount than the cash we distribute, our common unitholders will be required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, even if our common unitholders receive no cash distributions from us.  Our common unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income.

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

The anticipated after-tax economic benefit of an investment in our common units depends largely on us being treated as a partnership for federal income tax purposes.  If less than 90% of the gross income of a publicly traded partnership, such as us, for any taxable year is “qualifying income” from sources such as the transportation, marketing (other than to end users), or processing of crude oil, natural gas or products thereof, interest, dividends or similar sources, that partnership will be taxable as a corporation under Section 7704 of the Internal Revenue Code for federal income tax purposes for that taxable year and all subsequent years.  We have not requested and do not plan to request a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes.

If we were treated as a corporation for federal income tax purposes, then we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay additional state income tax at varying rates.  Distributions would generally be taxed again to unitholders as corporate distributions and none of our income, gains, losses, deductions or credits would flow through to our unitholders.  Because a tax would be imposed upon us as a corporation, cash available for distribution to our unitholders would be substantially reduced.  Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to unitholders and thus would likely result in a substantial reduction in the value of our units.

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. In addition, 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 annually a Texas franchise tax at a maximum effective rate of 0.7% of our gross income apportioned to Texas with respect to the prior year.  Imposition of such a tax on us by Texas and, if applicable, by any other state will reduce the cash available for distribution to our unitholders.

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, the minimum quarterly distribution amount and the target distribution amounts will be adjusted to reflect the impact of that law on us.

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

The present 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 federal income tax laws and interpretations thereof may or may not be applied retroactively. Moreover, any such modification could make it more difficult or impossible for us to meet the exception which allows publicly traded partnerships that generate qualifying income to be treated as partnerships (rather than corporations) for U.S. federal income tax purposes, affect or cause us to change our business activities, or affect the tax consequences of an investment in our common units. For example, members of Congress have considered substantive changes to existing federal income tax laws that would affect the tax treatment of certain publicly traded partnerships. 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 units.

If the IRS contests any of the federal income tax positions we take, the market for our common units may be adversely affected, and the costs of any such contest will reduce our cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the conclusions of our counsel or from the positions we take. 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 of our counsel's conclusions or the positions we take. Any contest with the IRS may materially and adversely impact the market for our units and the price at which they trade. In addition, the costs of any contest with the IRS will be borne indirectly by our unitholders and our General Partner because the costs will reduce our cash available for distribution.

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

If our unitholders sell their units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those units. Because distributions to a unitholder which exceed the total net taxable income allocated to the unitholder decrease the unitholder's tax basis in his or her units, any such prior excess distribution will, in effect, become taxable income to the unitholder if the common units are sold by the unitholder at a price greater than their tax basis, even if the price the unitholder receives is less than the original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income to the selling unitholder due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder's share of our non-recourse liabilities, a unitholder who sells common units may incur a tax liability in excess of the amount of cash received from the sale.

Tax-exempt entities, regulated investment companies and non-United States persons face unique tax issues from owning units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, such as individual retirement accounts (known as IRAs), pension plans, regulated investment companies (known as 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 individual retirement accounts and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file United States federal income tax returns and pay tax on their share of our taxable income. If a potential unitholder is a tax-exempt entity or a non-U.S. person, it should consult its tax advisor before investing in our units.

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

Because we cannot match transferors and transferees of common units and because of other reasons, we will adopt depreciation and/or amortization positions that may not conform with all aspects of existing Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from their 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.

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

We will be considered to have terminated for federal income tax purposes if there are one or more transfers of interests in our partnership that together represent sales or exchanges of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met,

- multiple transfers of the same interest within a twelve month period will be counted only once; and

- if Vitol or Charlesbank sells or exchanges its interests in our General Partner, the interests held by our General Partner in us will be deemed to have been sold or exchanged.

While we would continue our existence as a Delaware limited partnership, our tax 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 (and our unitholders could receive two Schedules K-1 if relief is not available, as described below) for one fiscal year and could 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 twelve months of our taxable income or loss being includable in his taxable income for the year of termination. A tax termination would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections, and if we were to fail to recognize and report on our tax return that a termination occurred, we could be subject to penalties. The IRS has 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 required to provide only a single Schedule K-1 to unitholders for the year in which the termination occurs notwithstanding two partnership tax years.

Our unitholders likely will be subject to state and local taxes and return filing or withholding requirements in states in which they do not live as a result of investing in our units.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, such as state and local income taxes, unincorporated business taxes and estate, inheritance, or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property. Our unitholders may be required to file state and local income tax returns and pay state and local income taxes in certain of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently own property and conduct business in Texas, Oklahoma, Kansas, Colorado, New Mexico, Arkansas, California, Georgia, Idaho, Illinois, Indiana, Missouri, Michigan, Montana, Nebraska, Nevada, New Jersey, Ohio, Pennsylvania, Tennessee, Utah, Virginia and Washington. Most of these states currently impose income taxes on corporations, and many of these states impose income taxes on other entities and nonresident individuals. We may own property or conduct business in other states or foreign countries in the future. It is each unitholder’s responsibility to file all federal, state and local tax returns. Under the tax laws of some states where we will conduct business, we may be required to withhold a percentage from amounts to be distributed to a unitholder who is not a resident of that state. For example, in the case of Oklahoma, we are required to either report detailed tax information about our non-Oklahoma resident unitholders with an income in Oklahoma in excess of $500 to the taxing authority, or withhold an amount equal to 5% of the portion of our distributions to unitholders which is deemed to be the Oklahoma share of our income. Our counsel has not rendered an opinion on the state and local tax consequences of an investment in our common units.

We have transferred certain assets located at certain of our asphalt facilities and which could generate non-qualifying income to a subsidiary taxed as a corporation. Such subsidiary is subject to entity level federal and state income taxes on its net taxable income and, if a material amount of entity-level taxes were incurred, then our cash available for distribution to our unitholders could be substantially reduced.

We have entered into storage contracts and leases with third party customers with respect to substantially all of our asphalt facilities. At the time of entering into such agreements, it was unclear under current tax law as to whether the rental income from the leases, and whether the fees attributable to certain of the processing services we provide under certain of the storage contracts, constitute “qualifying income.” In the second quarter of 2009, we submitted a request for a ruling from the IRS that rental income from the leases constitutes “qualifying income.” In October 2009, we received a favorable ruling from the IRS. As part of this ruling, however, we agreed to transfer, and have transferred, certain of our asphalt processing assets and related fee income, to a subsidiary taxed as a corporation. Such subsidiary is required to pay federal income tax on its income at the corporate tax rate, which is currently a maximum of 35%, and will likely pay state (and possibly local) income tax at varying rates. Distributions from such subsidiary will generally be taxed again to unitholders as corporate distributions and none of the income, gains, losses, deductions or credits of such subsidiary will flow through to our unitholders. If a material amount of entity-level taxes are incurred by such subsidiary, then our cash available for distribution to its unitholders could be substantially reduced.

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

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

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

Because a unitholder whose units are loaned to a "short seller" to effect a short sale of units may be considered as having disposed of the loaned units, such unitholder 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 units are loaned to a short seller to effect a short sale of 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 consult a tax advisor to discuss whether it is advisable modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

Unitholders converting preferred units into common unit could under certain limited circumstances receive a gross income allocation that may materially increase the taxable income allocated to such unitholders.

Under our partnership agreement and in accordance with proposed Treasury Regulations, immediately after the conversion of a preferred unit, we will adjust the capital accounts of all of our partners to reflect any positive difference ("Unrealized Gain") or negative difference ("Unrealized Loss") between the fair market value and the carrying value of our assets at such time as if such Unrealized Gain or Unrealized Loss had been recognized on an actual sale of each such asset for an amount equal to its fair market value at the time of such conversion. Such Unrealized Gain or Unrealized Loss (or items thereof) will be allocated first to the converting preferred unitholder in respect of common units received upon the conversion until the capital account of each such common unit is equal to the per unit capital account for each existing common unit. This allocation of Unrealized Gain or Unrealized Loss will not be taxable to the converting preferred unitholder or to any other unitholders. If the Unrealized Gain or Unrealized Loss allocated as a result of the conversion of a preferred unit is not sufficient to cause the capital account of each common unit received upon such conversion to equal the per unit capital account for each existing common unit, then capital account balances will be reallocated among the unitholders as needed to produce this result. In the event that such a reallocation is needed, a converting preferred unitholder would be allocated taxable gross income in an amount equal to the amount of any such reallocation to it.

We may adopt certain valuation methodologies and monthly conventions for federal income tax purposes that may result in a shift of income, gain, loss and deduction between our General Partner and our common unitholders. The IRS may challenge this treatment, which could adversely affect the value of our outstanding units.

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

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

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

A description of our properties is contained in "Item 1-Business."

Title to Properties

Substantially all of our pipelines are constructed on rights-of-way granted by the apparent record owners of the property. Lands over which pipeline rights-of-way have been obtained may be subject to prior liens that have not been subordinated to the right-of-way grants. We have obtained, where necessary, easement agreements from public authorities and railroad companies to cross over or under, or to lay facilities in or along, watercourses county roads, municipal streets, railroad properties and state highways, as applicable. In some cases, property on which our pipelines were built was purchased in fee. Our crude oil terminals are on real property owned or leased by us.

Our asphalt assets are on real property owned or leased by us. Some of the real property leases that were transferred to us as part of the acquisition of our asphalt assets required the consent of the counterparty to such lease. In certain instances, we have not entered into new leases with a lessor although we continue to use such leases and make payments to the lessor and are in the process of negotiating new leases.

Other than as described above, we believe that we have satisfactory title to all of our assets. Although title to such properties is subject to encumbrances in certain cases, such as customary interests generally retained in connection with acquisition of real property, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens and minor easements, restrictions and other encumbrances to which the underlying properties were subject at the time of acquisition by our predecessor or us, we believe that none of these burdens will materially interfere with their use in the operation of our business.

Item 3. Legal Proceedings.

On October 27, 2008, Keystone Gas Company ("Keystone") filed suit against us in Oklahoma State District Court in Creek County alleging that it is the rightful owner of certain segments of our pipelines and related rights of way, located in Payne and Creek Counties, that we acquired from SemCorp in connection with our initial public offering in 2007. Keystone seeks to quiet title to the specified rights of way and pipelines and seeks damages up to the net profits derived from the disputed pipelines. There has been no determination of the extent of potential damages for our use of such pipelines. We have filed a counterclaim against Keystone alleging that it is wrongfully using a segment of a pipeline that is owned by us in Payne and Creek Counties. The parties are engaged in discovery. We intend to vigorously defend these claims. No trial date has been set by the court.

In March and April 2009, nine current or former executives of SemCorp and certain of its affiliates filed wage claims with the Oklahoma Department of Labor against our General Partner. Their claims arise from our General Partner's Long-Term Incentive Plan, Employee Phantom Unit Agreement ("Phantom Unit Agreement"). Most claimants alleged that phantom units previously awarded to them vested upon the Change of Control that occurred in July 2008. One claimant alleged that his phantom units vested upon his termination. The claimants contended our General Partner's failure to deliver certificates for the phantom units within 60 days after vesting caused them to be damaged, and they sought recovery of approximately $2.0 million in damages and penalties. On April 30, 2009, all of the wage claims were dismissed on jurisdictional grounds by the Department of Labor.

On July 8, 2009, the nine executives filed suit against our General Partner in Tulsa County district court claiming they are entitled to recover the value of phantom units purportedly due them under the Phantom Unit Agreement. The claimants asserted claims against our General Partner for alleged failure to pay wages and breach of contract and sought to recover the alleged value of units in the total amount of approximately $1.3 million, plus additional damages and attorneys' fees. After the suit was filed, we distributed phantom units to certain of the claimants. On April 14, 2010, a Tulsa County district court judge ruled in favor of seven of the claimants, and awarded them approximately $1.0 million in damages. We appealed this ruling. On October 22, 2010, our General Partner was ordered to pay $0.2 million in attorneys' fees. We also appealed this order.

On December 20, 2012, the Oklahoma Court of Civil Appeals issued its opinion on the appeals we filed. The appellate court determined the phantom unit awards were not wages under the applicable statute, but affirmed the trial court's decision as

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to a breach of contract of the Phantom Unit Agreement by us. The appellate court remanded the case for a hearing to determine the amount of damages and attorneys' fees to which claimants were entitled based on the breach of contract. We have filed a petition for rehearing asserting the trial court must take mitigation into account when calculating the breach of contract damages and that a prevailing party attorneys' fee is not available under the controlling Oklahoma statute. Cross-motions have been filed in the appellate court seeking attorney's fees and costs incurred during the pendency of the appeal. The Oklahoma Court of Civil Appeals has not issued rulings on these motions. While we believe we have meritorious defenses against the damages and attorneys' fees sought to be recovered, the ultimate resolution of the matter cannot be determined.

On February 13, 2013, we filed suit against Koch Industries, Inc. (together with its subsidiaries, "Koch"), a previous owner of our asphalt facility located in Northumberland, Pennsylvania. The suit was filed in the United States District Court for the Middle District of Pennsylvania. We are seeking a declaration that Koch is responsible for any assessment and cleanup costs related to certain environmental liabilities. To date, Koch has not filed an answer to the complaint. Koch has previously taken the position that we have the responsibility to assess the polychlorinated biphenyl ("PCB") contamination at such facility although the contamination occurred prior to our becoming the owner of such facility. We intend to vigorously pursue the litigation.

On July 11, 2011, ExxonMobil filed suit against us in Harris County District Court, State of Texas, requesting damages in excess of $35,000 from us and other third party service providers in connection with the relocation of existing pipelines owned by ExxonMobil and us. We have filed our answer to the claims and asserted cross-claims against third party service providers including the subcontractors of ExxonMobil. ExxonMobil had previously sent a settlement demand seeking approximately $1.9 million in damages. We intend to vigorously defend these claims.

On February 6, 2012, the Partnership filed suit against SemCorp and others in Oklahoma County district court. In the suit, the Partnership is seeking a judgment that SemCorp immediately return approximately 140,000 barrels of crude oil linefill belonging to the Partnership, and the Partnership is seeking judgment in an amount in excess of $75,000 for actual damages, special damages, punitive damages, pre-judgment interest, reasonable attorney's fees and costs, and such other relief that the Court deems equitable and just. On March 22, 2012, SemCorp filed a motion to dismiss and transfer to Tulsa County. On April 18, 2012, SemCorp filed a motion for summary judgment, and, on May 1, 2012, the district court of Oklahoma County ordered a transfer to Tulsa County. The Partnership is contesting SemCorp's motion for summary judgment, which has been referred to a special master for report and recommendation. Discovery, before the special master, is ongoing and no trial date is set.

On July 13, 2012, we and one of our employees were named in a motor vehicle negligence suit in the District Court of Woodward County, Oklahoma arising out of an accident involving one of our crude oil tanker trucks. The accident resulted in the death of one of the occupants of the other vehicle and certain unknown injuries to the other occupant. The plaintiff is seeking damages in excess of $75,000 from us. We have submitted the claim to our insurance carriers, and we believe that any recovery would be within applicable policy limits after payment of our $100,000 deductible. Although it is not possible to predict the ultimate outcome of this matter, we do not expect that an award in this matter will have a material adverse impact on its consolidated results of operations or financial condition.

We may become the subject of additional private or government actions regarding these matters in the future. Litigation may be time-consuming, expensive and disruptive to normal business operations, and the outcome of litigation is difficult to predict. The defense of these claims and lawsuits may result in the incurrence of significant legal expense. The litigation may also divert management's attention from our operations which may cause our business to suffer. An unfavorable outcome in any of these matters may have an adverse effect on our business, financial condition, results of operations, cash flows, ability to make distributions to our unitholders, the trading price of our common units and ability to conduct our business. All or a portion of the defense costs and any amount we may be required to pay to satisfy a judgment or settlement of these claims may not be covered by insurance.

## Item 4. Mine Safety Disclosures.

None.

# PART II.

## Item 5. Market for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities.

Effective at the opening of business on February 20, 2009, trading in our common units was suspended on Nasdaq due to our failure to timely file our periodic reports with the SEC, and our common units were subsequently delisted from

Nasdaq. Our common units were then traded on the Pink Sheets, which is an over-the-counter securities market, under the symbol BKEP.PK. On May 16, 2011, our common units were relisted and resumed trading on the Nasdaq Global Market exchange under the symbol "BKEP."

On March 7, 2013, there were 22,675,135 common units outstanding, held by approximately 18 unitholders of record of our common units. The actual number of unitholders is greater than the number of holders of record. We have also issued 30,159,958 Preferred Units, which began trading on the Nasdaq Global Market under the symbol "BKEPP" on November 14, 2011. 18,312,968 of the Preferred Units are held by Vitol and Charlesbank.

The following table shows the high and low sales prices per common unit, as reported by Nasdaq or the Pink Sheets, as applicable, as well as distributions declared by quarter for the periods indicated. The quotations from the Pink Sheets reflect inter-dealer prices, without retail mark-up, mark-down or commission and may not necessarily represent actual transactions.

| Common Units(1) | Low | High | Cash Distribution per Unit(2) |
|---|---|---|---|
| 2011: | | | |
| First Quarter | $7.25 | $8.82 | $— |
| Second Quarter | 6.88 | 9.00 | — |
| Third Quarter | 6.11 | 9.00 | — |
| Fourth Quarter | 4.95 | 6.99 | 0.1100 |
| 2012: | | | |
| First Quarter | $6.31 | $7.86 | $0.1100 |
| Second Quarter | 6.50 | 7.32 | 0.1100 |
| Third Quarter | 6.17 | 6.89 | 0.1125 |
| Fourth Quarter | 6.08 | 6.70 | 0.1150 |
| Preferred Units(3) | | | |
| 2011: | | | |
| First Quarter | N/A | N/A | $0.2402 |
| Second Quarter | N/A | N/A | 0.1381 |
| Third Quarter | N/A | N/A | 0.1381 |
| Fourth Quarter | $7.33 | $9.85 | 0.1682 |
| 2012: | | | |
| First Quarter | $7.00 | $9.99 | $0.1788 |
| Second Quarter | 8.31 | 10.45 | 0.1788 |
| Third Quarter | 8.30 | 9.00 | 0.1788 |
| Fourth Quarter | 8.30 | 8.81 | 0.1788 |

(1) Our common units were traded on the Pink Sheets until May 16, 2011, when they were relisted on the NASDAQ Global Market.

(2) We did not make a distribution to our common unitholders or subordinated unitholders for the quarter ended June 30, 2008 through the quarter ended September 30, 2011 due, in part, to the events of default and covenants under our prior credit agreement and the uncertainty of our future cash flows.

(3) Our Preferred Units began trading on the Nasdaq on November 14, 2011.

Distributions of Available Cash

Our partnership agreement requires that, 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.

Available cash, for any quarter, consists of all cash on hand at the end of that quarter:

- less the amount of cash reserves established by our General Partner to:
  provide for the proper conduct of our business;
  comply with applicable law, any of our debt instruments or other agreements; or
  provide funds for distributions to our unitholders for any one or more of the next four quarters;
- plus all additional cash and cash equivalents on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter. Working capital borrowings are generally borrowings that are made under a credit facility, commercial paper facility or similar financing arrangement, and in all cases are used solely for working capital purposes or to pay distributions to partners and with the intent of the borrower to repay such borrowings within 12 months.

Pursuant to our credit facility, as amended in March 2013, we are permitted to make quarterly distributions of available cash to unitholders so long as: (i) no default or event of default exists under our credit agreement, (ii) we have, on a pro forma basis after giving effect to such distribution, at least $10.0 million of availability under the revolving loan facility, and (iii) our consolidated total leverage ratio, on a pro forma basis, would not be greater than 4.50 to 1.00. Our consolidated total leverage ratio (calculated in accordance with our credit agreement) as of December 31, 2012 was 3.04 to 1.00.

Distributions of Available Cash from Operating Surplus during the Eight Quarter Period

We will make distributions of available cash from operating surplus for any quarter during the eight quarter period ended June 30, 2013 (the “Eight Quarter Period”) in the following manner:

- first, 97.9% to the holders of the Preferred Units, pro rata, and 2.1% to our General Partner, until we distribute for each outstanding Preferred Unit an amount equal to the Series A Quarterly Distribution Amount (as defined below) for that quarter;
- second, 97.9% to the holders of the Preferred Units, pro rata, and 2.1% to our General Partner, until we distribute for each outstanding Preferred Unit an amount equal to any arrearages in the payment of the Series A Quarterly Distribution Amount for any prior quarters; and
- thereafter, 97.9% to all unitholders holding common units, pro rata, and 2.1% to our General Partner.

Series A Quarterly Distribution Amount means (i) in the case of any quarter or partial quarter during the period ending on October 25, 2011, $0.138125 per unit and (ii) thereafter, $0.17875 per unit.

The preceding discussion is based on the assumptions that our General Partner maintains its 2.1% general partner interest and that we do not issue additional classes of equity securities.

Distributions of Available Cash from Operating Surplus after the Eight Quarter Period

Our partnership agreement requires that we make distributions of available cash from operating surplus for any quarter after the Eight Quarter Period in the following manner:

- first, 97.9% to the holders of Preferred Units, pro rata, and 2.1% to our General Partner, until we distribute for each outstanding Preferred Unit an amount equal to the Series A Quarterly Distribution Amount for that quarter;
- second, 97.9% to the holders of Preferred Units, pro rata, and 2.1% to our General Partner, until we distribute for each outstanding Preferred Unit an amount equal to any arrearages in the payment of the Series A Quarterly Distribution Amount for any prior quarters;
- third, 97.9% to all common unitholders and Class B unitholders, pro rata, and 2.1% to our General Partner, until we distribute for each outstanding common and Class B unit an amount equal to the minimum quarterly distribution of $0.11 per unit for that quarter; and

• thereafter, in the manner described in "-General Partner Interest and Incentive Distribution Rights" below.

The preceding discussion is based on the assumptions that our General Partner maintains its 2.1% general partner interest and that we do not issue additional classes of equity securities.

General Partner Interest and Incentive Distribution Rights

Our partnership agreement provides that our General Partner will be entitled to an approximate 2.1% of all distributions that we make prior to our liquidation. Our General Partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its approximate 2.1% general partner interest if we issue additional units. Our General Partner's approximate 2.1% interest, and the percentage of our cash distributions to which it is entitled, will be proportionately reduced if we issue additional units in the future (other than the issuance of partnership securities issued in connection with a reset of the incentive distribution target levels relating to our General Partner's incentive distribution rights or the issuance of partnership securities upon conversion of outstanding partnership securities) and our General Partner does not contribute a proportionate amount of capital to us in order to maintain its then current general partner interest. Our General Partner will be entitled to make a capital contribution in order to maintain its then current general partner interest in the form of the contribution to us of common units based on the current market value of the contributed common units.

Incentive distribution rights represent the right to receive an increasing percentage (13%, 23% and 48%) of quarterly distributions of available cash from operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved. Our General Partner currently holds the incentive distribution rights, but may transfer these rights separately from its general partner interest, subject to restrictions in the partnership agreement.

The following discussion assumes that our General Partner maintains its approximate 2.1% general partner's interest and continues to own the incentive distribution rights.

If for any quarter after the Eight Quarter Period:

- we have distributed available cash from operating surplus to the holders of our Preferred Units in an amount equal to the Series A Quarterly Distribution Amount;
- we have distributed available cash from operating surplus to the holders of our Preferred Units in an amount necessary to eliminate any cumulative arrearages in the payment of the Series A Quarterly Distribution Amount; and
- we have distributed available cash from operating surplus to the common unitholders and Class B unitholders in an amount equal to the minimum quarterly distribution;

then, our partnership agreement requires that we distribute any additional available cash from operating surplus for that quarter among the unitholders and our General Partner in the following manner:

- first, 97.9% to all unitholders holding common units or Class B units, pro rata, and 2.1% to our General Partner, until each unitholder receives a total of $0.1265 per unit for that quarter (the "first target distribution");
- second, 84.9% to all unitholders holding common units or Class B units, pro rata, and 15.1% to our General Partner, until each unitholder receives a total of $0.1375 per unit for that quarter (the "second target distribution");
- third, 74.9% to all unitholders holding common units or Class B units, pro rata, and 25.1% to our General Partner, until each unitholder receives a total of $0.1825 per unit for that quarter (the "third target distribution"); and
- thereafter, 49.9% to all unitholders holding common units or Class B units, pro rata, and 50.1% to our General Partner.

For equity compensation plan information, see "Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters-Securities Authorized for Issuance under Equity Compensation Plans."

Unregistered Sales of Securities

None.

Item 6. Selected Financial Data.

The following table shows selected historical financial and operating data of Blueknight Energy Partners, L.P. for the periods and as of the dates presented. Our results of operations for the years ended December 31, 2010, 2009 and 2008 were affected by SemCorp's bankruptcy filings and related events, which resulted in decreased revenues and increased expenses.

Prior to SemCorp's bankruptcy filings and our subsequent settlement with SemCorp in such bankruptcy proceedings in April of 2009, we were party to various agreements with SemCorp and its subsidiaries. After the rejection of such agreements in SemCorp's bankruptcy proceedings, we experienced decreased volumes of crude oil that was terminalled, stored, transported and gathered as compared to our agreements with SemCorp. In addition, we have also experienced decreased revenues in our asphalt services business as compared to the revenues that we received under our terminalling agreement with SemCorp. In addition, we have experienced increased expenses since SemCorp's Bankruptcy Filings, including increased general and administrative expenses related to the costs of legal and financial advisors, increased interest expense related to certain events of default under and associated amendments of our prior credit facility and expenses incurred to refinance our prior credit facility. For these reasons and due to the other factors described in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation-Overview-Items Impacting the Comparability of Our Financial Results," our results of operations are not comparable to our predecessor's historical results and our historical results may not be indicative of our future results.

We derived the information in the following table from, and that information should be read together with and is qualified in its entirety by reference to, the historical financial statements and the accompanying notes thereto, including those included elsewhere in this annual report. The table should be read together with "Item 1. Business" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

| | 2008 | 2009 | 2010 | 2011 | 2012 |
|---|---|---|---|---|---|
| Statement of Operations Data: | (in thousands, except for per unit data) | | | | |
| Service revenues: | | | | | |
| Third party revenue | $48,295 | $124,701 | $129,083 | $132,618 | $134,242 |
| Related party revenue[(1)] | 143,885 | 32,075 | 23,541 | 44,089 | 48,153 |
| Total revenue | 192,180 | 156,776 | 152,624 | 176,707 | 182,395 |
| Expenses: | | | | | |
| Operating | 103,827 | 98,572 | 97,713 | 117,851 | 126,262 |
| General and administrative | 43,085 | 28,137 | 20,454 | 17,311 | 19,795 |
| Total expenses | 146,912 | 126,709 | 118,167 | 135,162 | 146,057 |
| Gain (loss) on sale of assets | (251 ) | 2,447 | 58 | 3,008 | 7,250 |
| Gain on settlement transaction | — | 2,585 | — | — | — |
| Loss contingency, net of expected insurance recovery | — | — | 7,200 | — | — |
| Operating income | 45,017 | 35,099 | 27,315 | 44,553 | 43,588 |
| Other (income) expense | | | | | |
| Interest expense[(2)] | 26,951 | 51,399 | 48,638 | 32,898 | 11,705 |
| Change in fair value of embedded derivative within convertible debt | — | — | 6,650 | (20,224 ) | — |
| Change in fair value of rights offering contingency | — | — | (4,384 ) | (1,883 ) | — |
| Income (loss) before income taxes | 18,066 | (16,300 ) | (23,589 ) | 33,762 | 31,883 |
| Provision for income taxes | 291 | 205 | 207 | 287 | 318 |
| Net income (loss) | $17,775 | $(16,505 ) | $(23,796 ) | $33,475 | $31,565 |
| Allocation of net income (loss) for purpose of calculating earnings per unit: | | | | | |
| General partners interest in net income (loss) | $3,646 | $(326 ) | $(470 ) | $912 | $774 |
| Preferred partners interest in net income | $— | $— | $— | $16,446 | $21,564 |
| Accretion of discount on increasing rate preferred units | $— | $— | $— | $2,243 | $— |
| Beneficial conversion feature attributable to preferred units | $— | $— | $8,114 | $43,259 | $1,853 |
| Beneficial conversion feature attributable to repurchase of preferred units | $— | $— | $— | $(6,892 ) | $— |
| Gain on extinguishment attributable to redemption of convertible debt, recorded as a capital transaction | $— | $— | $— | $(2,375 ) | $— |
| Net Income (loss) available to limited partners | $14,129 | $(16,179 ) | $(31,440 ) | $(20,118 ) | $7,374 |
| Basic and diluted net income (loss) per limited partner unit: | | | | | |
| Common units | $0.45 | $(0.47 ) | $(0.91 ) | $(0.61 ) | $0.32 |
| Subordinated Units | $0.45 | $(0.47 ) | $(0.91 ) | $(0.52 ) | $— |
| Cash distributions per unit to limited partners[(3)]: | | | | | |
| Paid | $0.74 | $— | $— | $— | $0.44 |
| Declared | $0.40 | $— | $— | $0.11 | $0.45 |
| Cash distributions per unit to preferred partners: | | | | | |
| Paid | NA | NA | $— | $0.52 | $0.71 |
| Declared | NA | NA | $0.10 | $0.58 | $0.72 |
| | | | | | |
| Balance Sheet Data (at period end): | | | | | |
| Property, plant and equipment, net | $284,489 | $274,492 | $274,069 | $266,355 | $267,741 |
| Total assets | 354,641 | 310,701 | 323,838 | 304,755 | 299,825 |
| Long-term debt and capital lease obligations | 449,221 | 419,000 | 244,329 | 220,781 | 212,006 |

| | | | | | |
|---|---|---|---|---|---|
| Total partners' capital (deficit) | (126,643 ) | (142,179 ) | (37,743 ) | 57,799 | 58,655 |

(1) For the twelve months ended December 31, 2008, 2009, 2010, 2011 and 2012 we recognized revenues of $143.9 million, $26.5 million, $1.0 million, $0.5 million and $0.3 million, respectively, for services provided to SemCorp. Of these amounts, $143.9 million and $26.3 million are classified as related party revenues for the twelve months ended December 31, 2008 and 2009, respectively, while $0.2 million, $1.0 million, $0.5 million and $0.3 million are classified as third party revenue for the twelve months ended December 31, 2009, 2010, 2011 and 2012, respectively. Additionally, we provide services to Vitol. For the twelve months ended December 31, 2008, 2009, 2010, 2011 and 2012, we recognized revenues of $6.6 million, $9.4 million, $23.2 million, $44.1 million and $48.1 million, respectively, for services provided to Vitol. Of these amounts, $6.6 million and $8.4 million are classified as third party revenues for the twelve months ended December 31, 2008 and 2009, respectively. In the twelve months ended December 31, 2009, $1.0 million in revenue for services provided to Vitol subsequent to the Vitol Change of Control (as defined below) is classified as related party revenue. All revenue for services provided to Vitol for the twelve months ended December 31, 2010, 2011 and 2012 is classified as related party revenue.

(2) Interest expense prior to October 25, 2010 includes interest expense incurred under our prior credit facility. Interest expense after October 25, 2010 includes interest expense under our credit facility and a long-term payable to related party, as well as amortization of debt issuance costs. Interest expense from October 25, 2010 through November 2011 includes amortization of the convertible subordinated debenture discount until their redemption.

(3) Cash distributions paid per unit to limited partners represent payments made per unit during the period stated. Cash distributions declared per unit to limited partners represent distributions declared per unit for the quarters within the period stated. Declared distributions were paid within 45 days following the close of each quarter.

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

### Overview

We are a publicly traded master limited partnership with operations in twenty-three states. We provide integrated terminalling, storage, gathering and transportation services for companies engaged in the production, distribution and marketing of crude oil and liquid asphalt cement. We manage our operations through four operating segments: (i) crude oil terminalling and storage services, (ii) crude oil pipeline services, (iii) crude oil trucking and producer field services, and (iv) asphalt services.

### Recent Events

A time line of certain recent events is set forth below.

- October 25, 2010 - We entered into a Global Transaction Agreement with Vitol and Charlesbank in connection with refinancing of our prior credit facility and issued preferred units to Vitol and Charlesbank in connection therewith. In addition, the Global Transaction Agreement provided that we would call a meeting of our unitholders and submit proposals relating to the reduction of the minimum quarterly distribution and targets related to the incentive distribution rights and the elimination of the cumulative common unit arrearage. Furthermore, Vitol and Charlesbank entered into an agreement whereby Charlesbank would purchase 50% of the ownership interest in the entity that owns our General Partner and 50% of our outstanding subordinated units from Vitol.
- November 12, 2010 - Charlesbank acquired a 50% ownership interest in the entity that owns our General Partner and 50% of our outstanding subordinated units from Vitol (the "Charlesbank Change of Control").
- May 12, 2011 - We, Vitol and Charlesbank entered into the First Amendment to Global Transaction Agreement to modify certain provisions relating to, among other things, the proposals to be submitted to our unitholders.
- September 14, 2011 - At a special meeting, our unitholders approved the proposals provided in the Global Transaction Agreement, including the reduction of the minimum quarterly distribution and targets related to the incentive distribution rights and the waiver of the cumulative common unit arrearages. As a result, Vitol and Charlesbank transferred all of our outstanding subordinated units to us and we canceled such subordinated units.
- October 3, 2011 - Pursuant to the Global Transaction Agreement, we commenced a rights offering. Pursuant to the terms of the rights offering, we distributed to our common unitholders of record as of the close of business on September 27, 2011, 0.5412 rights for each outstanding common unit, with each whole right entitling the holder to acquire, for a subscription price of $6.50, a newly issued Preferred Unit. The rights offering expired on October 31, 2011.
- November 1, 2011 - We announced the expiration of the rights offering. The rights offering was over-subscribed with total basic and over-subscription rights being exercised for over 20 million Preferred Units. Approximately 96% of basic subscription rights were exercised, leaving approximately 470,000 Preferred Units available to fulfill over-subscriptions. We issued a total of 11,846,990 Preferred Units to unitholders that exercised their rights, and we received proceeds of approximately $77 million from the rights offering. The net proceeds from the rights offering,

after deducting expenses, were used to redeem Convertible Debentures in the aggregate principal amount of $50 million, plus accrued interest thereon, that we issued to Vitol and Charlesbank (the “Convertible Debentures”) and to repurchase an aggregate of 3,225,494 Preferred Units from Vitol and Charlesbank.

- November 14, 2011 - The Preferred Units began trading on the NASDAQ Global Market under the symbol “BKEPP.”
- January 10, 2012 - We announced the future resignation of the Chief Executive Officer of our General Partner, Mr. James Dyer, who remained as Chief Executive Officer until his successor was appointed in September 2012. Mr. Dyer continued to serve on the Board until September 2012.
- January 24, 2012 - We announced the resumption of distributions on our common units. For the quarter ended December 31, 2011, the Partnership paid distributions of $0.11 per common unit and $0.17 per preferred unit to its common and preferred unitholders of record as of the close of business on February 3, 2012. The distributions were paid on February 14, 2012. We continued to make quarterly distributions throughout 2012.

- September 13, 2012 - The Board appointed Mr. Mark A. Hurley as the Chief Executive Officer of our General Partner, effective September 20, 2012. Mr. Francis Brenner, who is affiliated with Vitol, replaced Mr. James C. Dyer on the Board.
- October 23, 2012 - J. Michael Cockrell notified the Board of his resignation as President and Chief Operating Officer of our General Partner, effective as of October 31, 2012.
- November 2, 2012 - We amended our credit facility to permit Mr. Hurley to receive a non-voting economic interest in Blueknight GP Holding, LLC ("HoldCo"), the owner of our General Partner. Mr. Hurley's interest in HoldCo will vest over a five year period and entitle Mr. Hurley, to the extent vested, to (i) 2% of the total amount of proceeds and/or distributions in excess of $100,000,000 received by HoldCo in connection with a transaction resulting in a change of control of the Partnership, and (ii) 2% of the portion of any interim quarterly distribution received by HoldCo in excess of $1,250,000.
- March 4, 2013 - We amended our credit facility to, among other things, (i) eliminate the requirement that our consolidated total leverage ratio not exceed 4.00 to 1.00 for purposes of making distributions, (ii) increase our ability to make investments in joint ventures and subsidiaries without such joint ventures and subsidiaries becoming guarantors under our credit facility, and (iii) permit us to include projected EBITDA from material projects for purposes of calculating compliance with our credit facility's minimum consolidated interest coverage ratio and maximum consolidated total leverage ratio.

Our Revenues

Our revenues consist of (i) terminalling and storage revenues, (ii) gathering, transportation and producer field services revenues and (iii) fuel surcharge revenues. For the twelve months ended December 31, 2012, we derived approximately 26% of our revenues from services we provided to Vitol, with the remainder of our services being provided to third parties.

Terminalling and storage revenues consist of (i) storage service fees from actual storage used on a month-to-month basis; (ii) storage service fees resulting from short-term and long-term contracts for committed space that may or may not be utilized by the customer in a given month; and (iii) terminal throughput service charges to pump crude oil to connecting carriers or to deliver asphalt product out of our terminals. Terminal throughput service charges are recognized as the crude oil exits the terminal and is delivered to the connecting crude oil carrier or third-party terminal and as the asphalt product is delivered out of our terminal. Storage service revenues are recognized as the services are provided on a monthly basis. We earn terminalling and storage revenues in two of our segments: (i) crude oil terminalling and storage services and (ii) asphalt services.

As of March 2013, we have approximately 6.0 million barrels of crude oil storage under service contracts with remaining terms ranging from month-to-month to 27 months, including 4.2 million barrels under contract to Vitol. As of March 2013, 2.1 million barrels of crude oil storage contracts were under month to month agreements or expire in 2013. We are in negotiations to contract the remaining storage capacity; however, there is no certainty that contracts will be renewed, or, if renewed, will be at the same or similar rates with the expiring contracts. If we are unable to renew the majority of the expiring storage contracts, we may experience lower utilization of our assets which could have a material adverse effect on our business, cash flows, ability to make distributions to our unitholders, the price of our common units, results of operations and ability to conduct our business.

Historically, the majority of our storage contracts have been for relatively short terms consisting of month-to-month or one year or less, and we have been able to contract for higher rates because of the near term expiration and market demand at the Cushing Interchange. Over the past two years we have endeavored to increase the average duration of our contracts and diversify our storage customer base which has led to decreased average storage rates in return for increased average duration. Additionally, there are a number of market dynamics currently taking place at the Cushing Interchange, including: the reversal of Seaway pipeline, the construction of the Keystone pipeline and significant production increases in Kansas, Oklahoma and Texas that are creating new supply and demand challenges affecting the market price for West Texas Intermediate crude as compared to other crude types. We expect these market dynamics to continue in the near term in and around the Cushing Interchange and to have a near term impact on storage rates we charge our customers for services provided at the Cushing Interchange.

We have leases and storage agreements with third party customers relating to 43 of our 44 asphalt facilities. The majority of the leases and storage agreements related to these facilities have terms that expire between the end of 2016 and the end of 2018. We operate the asphalt facilities pursuant to the storage agreements while our contract counterparties operate the asphalt facilities that are subject to the lease agreements.

Gathering and transportation services revenues consist of service fees recognized for the gathering of crude oil for our customers and the transportation of crude oil to refiners, to common carrier pipelines for ultimate delivery to refiners or to terminalling and storage facilities owned by us and others. Revenue for the gathering and transportation of crude oil is recognized when the service is performed and is based upon regulated and non-regulated tariff rates and the related transport volumes. Producer field services revenue consists of a number of services ranging from gathering condensates from natural gas producers to hauling produced water to disposal wells. Revenue for producer field services is recognized when the service is performed. We earn gathering and transportation revenues in two of our segments: (i) crude oil pipeline services and (ii) crude oil trucking and producer field services.

During the twelve months ended December 31, 2012, we transported approximately 67,000 Bpd on our pipelines, an increase of 12% as compared to the twelve months ended December 31, 2011. Vitol accounted for 30% of volumes transported in 2012. Additionally, since the beginning of 2012, we have been evaluating our gathering systems located in Oklahoma to determine whether or not they are economically feasible to continue to operate after taking into consideration transported volumes, ongoing maintenance costs and risk. As a result we have idled approximately 100 miles of gathering pipeline that we have determined not economically viable, and we recognized a $1.0 million impairment charge related to these assets in the second quarter of 2012. The significant majority of any volumes that were displaced as a result of idling the pipeline has been retained by our crude oil transport trucks. We do not anticipate the idling of this gathering pipeline to have a significant impact on the overall future results of our operations.

For the twelve months ended December 31, 2012, we transported approximately 55,000 Bpd on our crude transport trucks, an increase of 18% as compared to the twelve months ended December 31, 2011. Vitol accounted for approximately 40% of volumes transported in 2012. While we see opportunity to increase the utilization of our crude oil trucking and producer field services assets due to high demand for our services in the markets we currently serve, demand outpaces supply for qualified drivers in this industry and is delaying our realization of complete utilization of these assets. We are actively pursuing additional drivers, and we anticipate increased utilization of these assets in 2013. However, there can be no assurance that our efforts will be successful.

Fuel surcharge revenues are comprised of revenues recognized for the reimbursement of fuel and power consumed to operate our asphalt product storage tanks and terminals. We recognize fuel surcharge revenues in the period in which the related fuel and power expenses are incurred.

Our Expenses

Operating expenses increased by $8.4 million, or 7%, for 2012 as compared to 2011. Approximately half of this increase is due to increases in compensation costs, including commissions, insurance and the recognition of compensation expense associated with awards under our General Partner’s long-term incentive plan. The remainder is primarily due to a $1.1 million increase in asset impairment expense in 2012 attributable to the idling of certain gathering lines associated with our Mid-Continent pipeline system and our Bay City, Michigan residual fuel facility. General and administrative expenses increased $2.5 million, or 14%, in 2012 as compared to 2011. The increase was driven by incremental compensation expense in the fourth quarter of 2012 related to the employment of our new Chief Executive Officer and costs associated with the departure of our former President and Chief Operating Officer and our former Executive Vice President - Products.

Maintenance capital expenditures were $9.8 million and $10.3 million and expansion capital expenditures were $17.9 million and $7.7 million in 2012 and 2011, respectively. Our interest expense decreased by $21.2 million during the twelve months ended December 31, 2012 as compared to the twelve months ended December 31, 2011 primarily as a result of our redemption of the Convertible Debentures in November 2011 with proceeds from the rights offering conducted in the fourth quarter of 2011 and the $15.1 million decrease in non-cash interest expense related to the amortization of the associated debt discount in 2011.

Income Taxes

As part of the process of preparing the consolidated financial statements, we are required to estimate the federal and state income taxes in each of the jurisdictions in which our subsidiary that is taxed as a corporation operates. This process involves estimating the actual current tax exposure together with assessing temporary differences resulting from differing treatment of items, such as depreciation, for tax and accounting purposes. These differences result in deferred tax assets and liabilities, which are included in our consolidated balance sheet. We must then assess, using all available positive and negative evidence, the likelihood that the deferred tax assets will be recovered from future taxable income. If we believe that recovery is not likely, we must establish a valuation allowance. To the extent we establish a valuation allowance or increase or decrease this allowance in a period, we must include an expense or reduction of expense within the tax provisions in the consolidated statement of operations.

Under ASC 740 – Accounting for Income Taxes, an enterprise must use judgment in considering the relative impact of negative and positive evidence. The weight given to the potential effect of negative and positive evidence should be commensurate with the extent to which it can be objectively verified. The more negative evidence that exists (a) the more positive evidence is necessary and (b) the more difficult it is to support a conclusion that a valuation allowance is not needed for some portion, or all of the deferred tax asset. Among the more significant types of evidence that we consider are:

- taxable income projections in future years,
- whether the carryforward period is so brief that it would limit realization of tax benefits,
- future revenue and operating cost projections that will produce more than enough taxable income to realize the deferred tax asset based on existing service rates and cost structures, and
- our earnings history exclusive of the loss that created the future deductible amount coupled with evidence indicating that the loss is an aberration rather than a continuing condition.

Given that our subsidiary that is taxed as a corporation has limited earnings history for purposes of determining the likelihood of realizing the benefits of the deferred tax assets, we have provided a full valuation allowance against our deferred tax asset as of December 31, 2012.

Our Assets and Services

Our network of assets provides our customers the flexibility to access multiple points for the receipt and delivery of crude oil and the terminalling, storage and processing of crude oil and asphalt cement.  Our operations have minimal direct exposure to changes in crude oil and asphalt cement prices, but the volumes of crude oil and asphalt cement we gather, transport, terminal or store are indirectly affected by commodity prices. We generate revenues by charging a fee for services provided at each transportation stage as crude oil is shipped from its origin at the wellhead to destination points such as the Cushing Interchange, to refineries in Oklahoma, Kansas and Texas or to pipelines and by charging a fee for services provided for the terminalling and storage of crude oil and asphalt cement.

- Crude oil terminalling and storage assets and services.  We provide crude oil terminalling and storage services at our terminalling and storage facilities located in Oklahoma and Texas.  We currently own and operate an aggregate of approximately 7.8 million barrels of storage capacity.  Of this storage capacity, approximately 6.6 million barrels are located at our terminal in Cushing, Oklahoma.  Our Cushing terminal is strategically located within the Cushing Interchange, one of the largest crude oil marketing hubs in the United States and the designated point of delivery specified in all NYMEX crude oil futures contracts.  Our terminals have a combined capacity to receive or deliver approximately 10.0 million barrels of crude oil per month.  We also own approximately 10 acres of additional land within the Cushing Interchange where we can develop additional storage capacity.
- Crude oil pipeline assets and services.  We own and operate three pipeline systems, the Mid-Continent system, the Longview system and the Eagle North system, collectively consisting of approximately 1,264 miles of pipelines that gather crude oil for our customers and transport it to refiners, to common carrier pipelines for ultimate delivery to refiners or to terminalling and storage facilities owned by us and others.  Our pipeline gathering and transportation system located in Oklahoma and the Texas Panhandle, which we refer to as the Mid-Continent system, has a combined length of approximately 770 miles.  Our second pipeline gathering and transportation system located in East Texas, which we refer to as the Longview system, consists of approximately 309 miles of tariff-regulated crude oil gathering pipeline.  Our third pipeline transportation system located in Oklahoma, which we refer to as the Eagle North Pipeline System, consists of approximately 185 miles of pipeline.
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Crude oil trucking and producer field services.  In addition to our pipelines, we use our approximately 164 owned or leased tanker trucks to gather crude oil in Kansas, Oklahoma, Texas, New Mexico and Colorado for our customers at remote wellhead locations generally not connected to pipeline and gathering systems and transport the crude oil to aggregation points and storage facilities located along pipeline gathering and transportation systems.  In connection with our gathering services, we also provide a number of producer field services, ranging from gathering condensates from natural gas producers to hauling production waste water to disposal wells.

- Asphalt Services.  Our 44 asphalt cement terminals are located in 22 states and as such are well positioned to provide asphalt services in the market areas they serve throughout the continental United States.  With our approximately 7.2 million barrels of total asphalt product and residual fuel oil storage capacity, we are able to provide our customers the ability to effectively manage their asphalt product storage and processing and marketing activities. We currently have storage contracts or leases with third party customers relating to 43 of our 44 asphalt facilities.

## Factors That Will Significantly Affect Our Results

Commodity Prices. Although our current operations have minimal direct exposure to commodity prices, the volumes of crude oil and liquid asphalt cement we gather, transport, terminal or store are indirectly affected by commodity prices. Petroleum product prices may be contango (future prices higher than current prices) or backwardated (future prices lower than current prices) depending on market expectations for future supply and demand. Our terminalling and storage services benefit most from an increasing price environment, when a premium is placed on storage, and our gathering and transportation services benefit most from a declining price environment, when a premium is placed on prompt delivery.

Volumes. Our results of operations are dependent upon the volumes of crude oil we gather, transport, terminal and store and asphalt we terminal, store and/or process. An increase or decrease in the production of crude oil from the oil fields served by our pipelines or an increase or decrease in the demand for crude oil in the areas served by our pipelines and storage facilities will have a corresponding effect on the volumes we gather, transport, terminal and store. The production and demand for crude oil and liquid asphalt cement are driven by many factors, including the price for crude oil.

Acquisition Activities. We may pursue acquisition opportunities. These acquisition efforts may involve assets that, if acquired, would have a material effect on our financial condition, results of operations and cash flows. We can give no assurance that any such acquisition efforts will be successful or that any such acquisition will be completed on terms considered favorable to us.

Organic Expansion Activities. We may pursue opportunities to expand our existing asset base and consider constructing additional assets in strategic locations. The construction of additions or modifications to our existing assets, and the construction of new assets, involve numerous regulatory, environmental, political, legal and operational uncertainties beyond our control and may require the expenditure of significant amounts of capital.

Distributions to our Unitholders. We may make distributions to holders of our Preferred Units and common units as well as to our General Partner. To the extent that substantially all of our cash generated by our operations is used to make such distributions, we expect that we will rely upon external financing sources, including commercial bank borrowings and other debt and equity issuances, to fund our acquisition and expansion capital expenditures, as well as our working capital needs.

## Distributions

We did not make a distribution to our common unitholders or subordinated unitholders from May 15, 2008 through February 13, 2012 due, in part, to the events of default that existed under our former credit agreement, restrictions under such credit agreement and the uncertainty of our future cash flows relating to SemCorp's bankruptcy filings. Our unitholders will be required to pay taxes on their share of our taxable income even though they did not receive a distribution for the quarters ended June 30, 2008 through September 31, 2011. We resumed distributions for common units on February 14, 2012 for the quarter ended December 31, 2011, and we continued to make quarterly distributions throughout 2012. The amount of distributions paid and the decision to make any distribution is determined by the Board, which has broad discretion to establish cash reserves for the proper conduct of our business and for future distributions to our unitholders. In addition, our cash distribution policy is subject to restrictions on distributions under our credit facility.

Vitol Storage Agreements

In March 2010, we entered into a crude oil storage services agreement with Vitol under which we began providing crude oil storage services to Vitol effective May 1, 2010 (the "2010 Vitol Storage Agreement"). The initial term of the 2010 Vitol Storage Agreement is five years commencing on May 1, 2010, subject to automatic renewal periods for successive one year periods until terminated by either party with ninety days prior notice. In March 2013, the 2010 Vitol Storage Agreement was amended to adjust the rates we charge Vitol for services provided under the agreement. We believe that the rates we charge Vitol under this agreement are fair and reasonable to us and our unitholders and are comparable with the rates we charge third parties. The Board's conflicts committee reviewed and approved this agreement, including the amendment thereto, in accordance with our procedures for approval of related party transactions and the provisions of the partnership agreement.

On June 1, 2012, the crude oil storage services agreement with Vitol previously entered into in 2008 expired according to its terms. In anticipation of such expiration, we entered into two new crude oil storage services agreements with Vitol under which we began providing additional crude oil storage services to Vitol effective June 1, 2012. Service revenues under the first agreement are based on the 1.0 million barrels of storage capacity of the crude oil storage tanks that are dedicated to Vitol under the service agreement. The initial term of the first agreement is from June 1, 2012 through May 31, 2013. In March 2013, this agreement was amended to extend the term through March 31, 2014 and to adjust the rates we charge Vitol for services provided under the agreement. Service revenues under the second agreement are based on the 0.5 million barrels of storage capacity of the crude oil storage tanks that are dedicated to Vitol under the service agreement. The initial term of the second agreement was from June 1, 2012 through November 30, 2012 and has since twice automatically renewed. In March 2013, this agreement was amended to extend the term through October 31, 2013 and to adjust the rates we charge Vitol for services provided under the agreement. We believe that the rates we charge Vitol under these agreements are fair and reasonable to us and our unitholders and are comparable with the rates we charge third parties. The Board’s conflicts committee reviewed and approved these agreements, including the amendments thereto, in accordance with our procedures for approval of related party transactions and the provisions of the partnership agreement.

During the third quarter of 2012, we entered into another 6-month storage agreement with Vitol effective September 1, 2012 (the “Vitol September 2012 Storage Agreement”). Service revenues under the Vitol September 2012 Storage Agreement are based on the 0.5 million barrels of storage capacity of the crude oil storage tanks that are dedicated to Vitol under the agreement. The initial term of the Vitol September 2012 Storage Agreement was from September 1, 2012 to February 28, 2013. In March 2013, the Vitol September 2012 Storage Agreement was amended to extend the term through October 31, 2013 and to adjust the rates we charge Vitol for services provided under the agreement. We believe that the rates we charge Vitol under this agreement are fair and reasonable to us and our unitholders and are comparable with the rates we charge third parties. The Board’s conflicts committee reviewed and approved this agreement, including the amendment thereto, in accordance with our procedures for approval of related party transactions and the provisions of the partnership agreement.

Results of Operations

The table below summarizes our financial results for the twelve months ended December 31, 2010, 2011 and 2012:

| | Year ended December 31, | | |
|---|---|---|---|
| | 2010 | 2011 | 2012 |
| Service revenues: | | | |
| Crude oil terminalling and storage revenues: | | | |
| Third party | $17,701 | $11,067 | $11,825 |
| Related party | 21,258 | 27,608 | 23,983 |
| Total crude oil terminalling and storage | 38,959 | 38,675 | 35,808 |
| Crude oil pipeline services revenues: | | | |
| Third party | 11,740 | 16,984 | 16,579 |
| Related party | 1,543 | 4,807 | 5,677 |
| Total crude oil pipeline services revenues | 13,283 | 21,791 | 22,256 |
| Crude oil trucking and producer field services revenues: | | | |
| Third party | 42,437 | 44,366 | 46,164 |
| Related party | 740 | 11,561 | 17,688 |
| Total crude oil trucking and producer field services revenues | 43,177 | 55,927 | 63,852 |
| Asphalt services revenues: | | | |
| Third party | 57,205 | 60,201 | 59,674 |
| Related party | — | 113 | 805 |
| Total asphalt services | 57,205 | 60,314 | 60,479 |
| Total revenues | 152,624 | 176,707 | 182,395 |
| Operating expenses: | | | |
| Crude oil terminalling and storage | 7,743 | 8,731 | 7,922 |
| Crude oil pipeline services | 13,131 | 21,387 | 24,037 |
| Crude oil trucking and producer field services | 43,751 | 52,319 | 58,133 |
| Asphalt services | 33,088 | 35,414 | 36,170 |
| Total operating expenses | 97,713 | 117,851 | 126,262 |
| General and administrative expenses | 20,454 | 17,311 | 19,795 |
| Loss contingency, net of insurance recovery | 7,200 | — | — |
| Gain on sale of assets | 58 | 3,008 | 7,250 |
| Operating income | 27,315 | 44,553 | 43,588 |
| Other (income) expense: | | | |
| Interest expense | 48,638 | 32,898 | 11,705 |
| Change in fair value of embedded derivative within convertible debt | 6,650 | (20,224 ) | — |
| Change in fair value of rights offering liability | (4,384 ) | (1,883 ) | — |
| Income tax expense | 207 | 287 | 318 |
| Net income | $(23,796 ) | $33,475 | $31,565 |

Year Ended December 31, 2012 Compared to the Year Ended December 31, 2011

Service revenues. Service revenues include revenues from crude oil terminalling and storage services, crude oil pipeline services, crude oil trucking and producer field services and asphalt services. Service revenues, including reimbursement revenues of $5.9 million and $6.9 million for the years ended December 31, 2012 and 2011, respectively, for fuel and power,

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property tax, and insurance expenses related to the operations of our liquid asphalt facilities, were $182.4 million for the year ended December 31, 2012, compared to $176.7 million for the year ended December 31, 2011, an increase of $5.7 million, or 3%.

Crude oil terminalling and storage revenue decreased by $2.9 million to $35.8 million for the year ended December 31, 2012 compared to $38.7 million for the year ended December 31, 2011 primarily as a result of lower storage fee rates as well as a result of our dismantling two 55,000 barrel tanks in 2011.

Crude oil pipeline services revenue increased by $0.5 million to $22.3 million for the year ended December 31, 2012 compared to $21.8 million for the year ended December 31, 2011 primarily due to tariff rate increases and consulting revenues earned under a shared services agreement with Vitol.

Crude oil trucking and producer field services revenue increased by $8.0 million to $63.9 million for the year ended December 31, 2012 compared to $55.9 million for the year ended December 31, 2011. This increase is primarily the result of higher rates for the majority of our crude oil trucking service contracts as well as increased utilization of our trucking assets.

Our asphalt services revenue, including reimbursement of fuel and power, property tax and insurance premiums, remained generally consistent at $60.5 million for the year ended December 31, 2012 compared to $60.3 million for the year ended December 31, 2011.

Operating expenses. Operating expenses were $126.3 million for the year ended December 31, 2012 compared to $117.9 million for the year ended December 31, 2011, an increase of $8.4 million, or 7%.

Crude oil terminalling and storage operating expenses decreased by $0.8 million to $7.9 million for the year ended December 31, 2012 compared to $8.7 million for the year ended December 31, 2011. This decrease is primarily attributed to lower storage tank maintenance costs and is driven by the timing of tank inspection activities.

Our crude oil pipeline services operating expenses increased by $2.6 million to $24.0 million for the year ended December 31, 2012 compared to $21.4 million for the year ended December 31, 2011. This increase is primarily due to an increase in compensation costs as well as a $1.0 million impairment expense recognized in 2012 as we idled gathering lines associated with our Mid-Continent pipeline system.

Our crude oil trucking and producer field services operating expenses increased by $5.8 million to $58.1 million for the year ended December 31, 2012 compared to $52.3 million for the year ended December 31, 2011. This increase was primarily driven by the increase in utilization of our trucking assets, which resulted in higher driver commissions, fuel and fleet maintenance costs.

Our asphalt operating expenses were $36.2 million for the year ended December 31, 2012 compared to $35.4 million for the year ended December 31, 2011, an increase of $0.8 million. Compensation expense increased $0.9 million primarily as a result of switching one of our facilities from leased to operated and the related hiring of operational personnel.

General and administrative expenses. General and administrative expenses increased by $2.5 million, or 14%, to $19.8 million for the year ended December 31, 2012 compared to $17.3 million for the year ended December 31, 2011. This increase is primarily the result of the employment of our new Chief Executive Officer and incremental costs associated with the departure of our former President and Chief Operating Officer and our former Executive Vice President - Products.

Gain on sale of assets. In the year ended December 31, 2012, we recognized gains on the sale of assets of $7.3 million. The gains are primarily a result of the sale of 60,000 barrels of excess crude oil linefill attributed to our Longview pipeline system in East Texas. The linefill was sold to Vitol for the market price for East Texas crude of $98.96 per barrel. This transaction resulted in a gain of approximately $4.5 million. The remaining gains resulted from the sale of surplus, used property and equipment.

Interest expense. Interest expense represents interest on borrowings under our credit facility as well as amortization of debt issuance costs and the debt discount related to the Convertible Debentures that were redeemed in November of 2011. Interest expense decreased by $21.2 million to $11.7 million for the year ended December 31, 2012 compared to $32.9 million for the year ended December 31, 2011. This decrease is primarily due to non-cash interest expense related to the Convertible Debentures, including the related debt discount, of $19.4 million for the year ended December 31, 2011 whereas we had no related expense for the year ended December 31, 2012 due to the redemption of the Convertible Debentures in the fourth quarter of 2011. Furthermore, a decrease in the weighted average debt outstanding for the year ended December 31, 2012 compared to the year ended December 31, 2011 reduced interest expense by $0.9 million.

Other (income) expense. Other income for the year ended December 31, 2011 included an increase of $1.9 million in the fair value of the rights offering liability and a decrease of $20.2 million in the fair value of the embedded derivative liability derived from the conversion option in the Convertible Debentures.

Year Ended December 31, 2011 Compared to the Year Ended December 31, 2010

Service revenues. Service revenues, including reimbursement revenues for fuel and power, property tax and insurance expenses related to the operations of our liquid asphalt facilities of $6.9 million, were $176.7 million for the twelve months ended December 31, 2011 compared to $152.6 million for the twelve months ended December 31, 2010, an increase of $24.1 million, or 16%.

Crude oil terminalling and storage revenues decreased by $0.3 million to $38.7 million for the twelve months ended December 31, 2011 compared to $39.0 million for the twelve months ended December 31, 2010 as a result of renegotiated storage rates as well as the result of our dismantling two 55,000 barrel tanks in 2011.

Our crude oil pipeline services revenue increased by $8.5 million to $21.8 million for the twelve months ended December 31, 2011 compared to $13.3 million for the twelve months ended December 31, 2010 as a result of increased utilization of our pipeline services assets.

Our crude oil trucking and producer field services revenue increased by $12.7 million to $55.9 million for the twelve months ended December 31, 2011 compared to $43.2 million for the twelve months ended December 31, 2010. This increase is due primarily to incremental revenues of $8.4 million attributed to the producer field services business we acquired in December 2010. In addition, higher rates for the majority of our crude oil trucking service contracts became effective August 1, 2011.

Our asphalt services revenue, including reimbursement of fuel and power, property tax and insurance premiums, increased by $3.1 million to $60.3 million for the twelve months ended December 31, 2011 compared to $57.2 million for the twelve months ended December 31, 2010. This increase is primarily due to several of our customers exceeding throughput thresholds that triggered additional fees during the third quarter.

Operating expenses. Operating expenses include salary and wage expenses and related taxes and depreciation and amortization expenses. Operating expenses increased by $20.2 million, or 21%, to $117.9 million for the twelve months ended December 31, 2011 compared to $97.7 million for the twelve months ended December 31, 2010. Crude oil terminalling and storage operating expenses increased by $1.0 million to $8.7 million for the twelve months ended December 31, 2011 compared to $7.7 million for the twelve months ended December 31, 2010. Our crude oil pipeline services operating expenses increased by $8.3 million to $21.4 million for the twelve months ended December 31, 2011 compared to $13.1 million for the twelve months ended December 31, 2010. Our crude oil trucking and producer field services operating expenses increased by $8.5 million to $52.3 million for the twelve months ended December 31, 2011 compared to $43.8 million for the twelve months ended December 31, 2010. Our asphalt operating expenses increased by $2.3 million to $35.4 million for the twelve months ended December 31, 2011 compared to $33.1 million for the twelve months ended December 31, 2010.

Compensation expense increased by $6.4 million to $39.9 million for the twelve months ended December 31, 2011 compared to $33.5 million for the twelve months ended December 31, 2010 due to our transition away from services provided by SemCorp, which required us to establish our own operational management team and directly employ our own personnel. This transition was completed in the second quarter of 2011.

Repair and maintenance expenses increased by $6.7 million to $15.3 million for the twelve months ended December 31, 2011.   Pipeline repair expense increased by $2.3 million to $3.2 million for the twelve months ended December 31, 2011.  In addition, pipeline leak and related environmental remediation expenses increased by $1.1 million to $1.7 million for the twelve months ended December 31, 2011.  We also had $1.5 million in tank repair expenses for the twelve months ended December 31, 2011 related to a tank inspection program implemented in the first quarter of 2011 in response to new regulation of the asphalt industry.

Furthermore, fuel expenses increased by $3.8 million to $11.4 million for the twelve months ended December 31, 2011.  Partially offsetting operating expenses is the recognition of $3.0 million in gains on the sale of assets during the twelve months ended December 31, 2011.  Operating expenses for the twelve months ended December 31, 2010 include a $0.8 million impairment charge related to an asphalt facility located in Morehead City, North Carolina that we sold in April 2010.  Operating expenses for the twelve months ended December 31, 2011 include impairment charges of $0.5 million and $0.3 million related to an office building located in St. Louis, Missouri and an office building located in Abilene, Texas, respectively. As of December 31, 2011, the office building in Abilene, Texas was classified as held for sale, and we subsequently sold this asset in January 2012.

General and administrative expenses. General and administrative expenses decreased by $3.2 million, or 16%, to $17.3 million for the twelve months ended December 31, 2011 compared to $20.5 million for the twelve months ended December 31, 2010. This decrease is primarily attributable to a $3.9 million decrease in legal, financial advisory and other professional expenses and was offset by a $1.3 million increase in compensation expense due to an increase in our headcount as we transitioned away from SemCorp and established our operational management team. In addition, a former member of the Board, Mr. Thomas L. Kivisto, forfeited 150,000 vested but unissued common units in October of 2011 related to phantom units awarded under the Plan in 2007 and 2008, pursuant to a settlement agreement between Mr. Kivisto and the SEC. As such, we recognized a gain of $0.8 million for the twelve months ended December 31, 2011 related to the clawback of the awards and the related compensation expense that had been recognized during the vesting period. The gain is reflected as a reduction of general and administrative expenses for the twelve months ended December 31, 2011.

Loss contingency, net of insurance recovery. Our results of operations for the twelve months ended December 31, 2010 includes $7.2 million of expense which is the result of a $20.2 million loss contingency related to the Class Action Litigation (see Note 3 to our audited financial statements) and insurance proceeds of $13.0 million. The Class Action Litigation was settled in October of 2011 for a net expense of $7.2 million to us, all of which was reflected in our results of operations in 2010.

Gain on sale of Assets. Our results of operations for the twelve months ended December 31, 2011 included gains on the sale of assets of $3.0 million primarily related to the sale of an asphalt facility in Ennis, TX and the sale of crude oil linefill.

Interest expense. Interest expense includes interest on long-term borrowings under our credit facility, payables to related parties and amortization of both debt issuance costs and the convertible debt discount. Interest expense decreased by $15.7 million to $32.9 million for the twelve months ended December 31, 2011 compared to $48.6 million for the twelve months ended December 31, 2010. Decreases in the weighted average interest rate of our credit facility and the weighted average debt outstanding due to the refinancing of our credit facility in October 2010 resulted in decreased interest expense of $29.4 million for the twelve months ended December 31, 2011, compared to the twelve months ended December 31, 2010. Also as a result of the refinancing, amortization of our debt issuance costs decreased by $2.4 million for the twelve months ended December 31, 2011 compared to the twelve months ended December 31, 2010. These decreases were partially offset by an increase in interest expense related to the Convertible Debentures of $3.4 million for the twelve months ended December 31, 2011 as compared to the twelve months ended December 31, 2010, as well as an $11.9 million increase in non-cash interest expense due to the amortization of the associated debt discount for the twelve months ended December 31, 2011 compared to the twelve months ended December 31, 2010. The twelve months ended December 31, 2010 also include $3.8 million of capitalized interest whereas we did not capitalize any interest in the twelve months ended December 31, 2011.

Other (income) expense. Other income for the year ended December 31, 2011 included a $20.2 million increase in the fair value of the embedded derivative liability derived from the conversion option in the Convertible Debentures and a decrease of $1.9 million in the fair value of the rights offering contingency. Other expense for the year ended December 31, 2010 included a $6.7 million decrease in the fair value of the embedded derivative liability derived from the conversion option in the Convertible Debentures, partially offset by a decrease of $4.4 million in the fair value of the rights offering contingency.

Effects of Inflation

In recent years, inflation has been modest and has not had a material impact upon the results of our operations.

Off Balance Sheet Arrangements

We do not have any off-balance sheet arrangements as defined by Item 303 of Regulation S-K.

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

The following table summarizes our sources and uses of cash for the twelve months ended December 31, 2010, 2011 and 2012:

| | Year ended December 31, | | |
|---|---|---|---|
| | 2010 | 2011 | 2012 |
| | (in millions) | | |
| Net cash provided by operating activities | $19.9 | $37.2 | $61.7 |
| Net cash used in investing activities | (22.2) | (10.6) | (17.5) |
| Net cash provided by(used in) financing activities | 1.6 | (30.1) | (42.3) |

Operating Activities. Net cash provided by operating activities was $61.7 million for the twelve months ended December 31, 2012, as compared to $37.2 million for the twelve months ended December 31, 2011. The increase in cash provided by operating activities is primarily the result of changes in working capital, which contributed to approximately $21.9 million of the increase.

Net cash provided by operating activities increased by $17.3 million for the twelve months ended December 31, 2011 as compared to the twelve months ended December 31, 2010. The increase in net cash provided by operating activities is primarily due to an increase in net income to $33.5 million for the twelve months ended December 31, 2011 from a net loss of $23.8 million for the twelve months ended December 31, 2010. The increase in net income was primarily the result of increased utilization of our pipeline assets, higher rates for the majority of our crude oil trucking service contracts beginning in August 2011 and incremental income attributed to the producer field services business we acquired in December 2010. In addition, cash provided by operating activities increased due to lower interest expense as a result of the refinancing of our debt in the fourth quarter of 2010.

Investing Activities. Net cash used in investing activities was $17.5 million for the twelve months ended December 31, 2012, as compared to $10.6 million of net cash used for the twelve months ended December 31, 2011. The increase in cash used in investing activities was primarily the result of a $9.7 million increase in capital expenditures and was offset by an increase of $2.7 million in proceeds from the sale of assets in the twelve months ended December 31, 2012. Capital expenditures in 2012 included maintenance capital expenditures of $9.8 million and expansion capital expenditures of $17.9 million.

Net cash used in investing activities was $10.6 million for the twelve months ended December 31, 2011 compared to $22.2 million for the twelve months ended December 31, 2010. This decrease is primarily related to decreased acquisition expenditures for the twelve months ended December 31, 2011 and an increase in proceeds from the sale of assets of $5.9 million for the twelve months ended December 31, 2011. Capital expenditures in 2011 included maintenance capital expenditures of $10.3 million and expansion capital expenditures of $7.7 million.

Financing Activities. Net cash used in financing activities was $42.3 million for the twelve months ended December 31, 2012, as compared to $30.1 million for the twelve months ended December 31, 2011. Financing activities for the twelve months ended December 31, 2012 consisted primarily of $32.2 million in distributions to our unitholders and net repayments on long term debt of $7.0 million.

Net cash used by financing activities was $30.1 million for the twelve months ended December 31, 2011 as compared to net cash provided by financing activities of $1.6 million for the twelve months ended December 31, 2010. For the twelve months ended December 31, 2011, we had cash outflows related to net repayments under our credit facility of $21.9 million, the redemption of the Convertible Debentures of $50.0 million, the repurchase of Preferred Units of

$21.0 million and distributions of $11.6 million. This was offset by proceeds from equity issuances of $77.0 million.

Our Liquidity and Capital Resources

Cash flow from operations and our credit facility are our primary sources of liquidity, although our ability to borrow such funds may be limited by the financial covenants in the credit facility. At December 31, 2012, we had a working capital deficit of $9.2 million. This is primarily a function of our approach to cash management. At December 31, 2012, we had approximately $83.7 million of availability under our revolving credit facility, although our ability to borrow such funds may be limited by the financial covenants in our credit facility. As of March 7, 2013, we have aggregate unused commitments under our revolving credit facility of approximately $62.5 million and cash on hand of approximately $3.7 million.

Capital Requirements. Our capital requirements consist of the following:

- maintenance capital expenditures, which are capital expenditures made to maintain the existing integrity and operating capacity of our assets and related cash flows further extending the useful lives of the assets; and
- expansion capital expenditures, which are capital expenditures made to expand or to replace partially or fully depreciated assets or to expand the operating capacity or revenue of existing or new assets, whether through construction, acquisition or modification.

Expansion capital expenditures for organic growth projects totaled $17.9 million in the twelve months ended December 31, 2012 compared to $7.7 million in the twelve months ended December 31, 2011. We currently expect expansion capital expenditures for organic growth projects to be approximately $40.0 million to $50.0 million in 2013. Maintenance capital expenditures totaled $9.8 million in the twelve months ended December 31, 2012 compared to $10.3 million in the twelve months ended December 31, 2011. We currently expect maintenance capital expenditures to be approximately $10.0 million to $13.0 million in 2013.

Our Ability to Grow Depends on Our Ability to Access External Expansion Capital. Our partnership agreement provides that we distribute all of our available cash to our unitholders. Available cash is reduced by cash reserves established by our General Partner to provide for the proper conduct of our business (including for future capital expenditures) and to comply with the provisions of our credit facility. We may not grow as quickly as businesses that reinvest their available cash to expand ongoing operations because we distribute all of our available cash.

Description of Credit Facility. On October 25, 2010, we entered into a new credit agreement, which we refer to as our credit agreement. Our credit agreement includes a $200.0 million term loan facility and, after giving effect to an April 5, 2011 amendment, a $95.0 million revolving credit facility. Vitol is a lender under our credit agreement and has committed to loan us $15.0 million pursuant to such agreement. The proceeds of loans made under our credit agreement may be used for working capital and other general corporate purposes.

Our credit agreement is guaranteed by all of our existing subsidiaries. Obligations under our credit agreement are secured by first priority liens on substantially all of our assets and those of the guarantors, including all material pipeline, gathering and processing assets, all material storage tanks and asphalt facilities, all material working capital assets and a pledge of all of our equity interests in our subsidiaries.

Our credit agreement includes procedures for adding financial institutions as revolving lenders or for increasing the revolving commitment of any currently committed revolving lender subject to an aggregate maximum of $200.0 million for all revolving loan commitments under our credit agreement.

The credit agreement will mature on October 25, 2014, and all amounts outstanding under our credit agreement shall become due and payable on such date. We may prepay all loans under our credit agreement at any time without premium or penalty (other than customary LIBOR breakage costs), subject to certain notice requirements. The credit agreement requires mandatory prepayments of amounts outstanding thereunder with the net proceeds of certain asset sales, casualty events and debt incurrences, and, in certain circumstances, with a portion of our excess cash flow (as defined in the credit agreement). These mandatory prepayments will be applied to the term loan under our credit agreement until it is repaid in full, then applied to reduce commitments under the revolving loan facility.

Borrowings under our credit agreement bear interest, at our option, at either (i) the ABR (the highest of the administrative agent's prime rate, the federal funds rate plus 0.5%, or the one-month eurodollar rate (as defined in the credit agreement) plus 1%), plus an applicable margin that ranges from 3.0% to 3.5%, or (ii) the eurodollar rate plus an applicable margin that ranges from 4.0% to 4.5%, in each case depending on our consolidated total leverage ratio (as defined in the credit agreement).

We pay a per annum fee on all letters of credit issued under the credit agreement, which fee equals the applicable margin for loans accruing interest based on the eurodollar rate, and we pay a commitment fee of 0.5% per annum on the unused availability under the credit agreement. The credit agreement does not have a floor for the ABR or the eurodollar rate. In connection with entering into our credit agreement, we paid certain upfront fees to the lenders thereunder, and we paid certain arrangement and other fees to the arranger and administrative agent of our credit agreement. Vitol received its pro rata portion of such fees as a lender under our credit agreement. During the twelve months ended December 31, 2012, our weighted average interest rate was 5.48%, including interest under the throughput capacity agreement with Vitol related to our Eagle North pipeline system and the amortization of debt issuance costs, resulting in interest expense of approximately $11.7 million.

In March 2013 we amended our credit facility to, among other things:

- eliminate the requirement that our consolidated total leverage ratio not exceed 4.00 to 1.00 for purposes of making distributions;
- increase our ability to make investments in joint ventures and subsidiaries without such joint ventures and subsidiaries becoming guarantors under our credit facility; and
- permit us to include projected EBITDA from material projects (generally being the construction or expansion of any capital project the aggregate budgeted capital cost of which exceeds $5.0 million) in our EBITDA for purposes of calculating compliance with our credit facility's minimum consolidated interest coverage ratio and maximum consolidated total leverage ratio. The amount of projected EBITDA from material projects that is included in such financial covenant calculations is subject to the credit facility administrative agent's approval, and the aggregate amount of all material project EBITDA adjustments during any period is limited to 15% of the total actual consolidated EBITDA for such period.

In connection with entering into the March 2013 credit facility amendment we paid a fee to the consenting lenders.

Our credit agreement 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 consolidated total leverage ratio is 4.50 to 1.00 for the fiscal quarter ending December 31, 2012 and each fiscal quarter thereafter. The minimum permitted consolidated interest coverage ratio (as defined in our credit agreement) is 3.00 to 1.00 for the fiscal quarter ending December 31, 2012 and each fiscal quarter thereafter.

In addition, our credit agreement contains various covenants that, among other restrictions, limit our ability to:

- create, issue, incur or assume indebtedness;
- create, incur or assume liens;
- engage in mergers or acquisitions;
- sell, transfer, assign or convey assets;
- repurchase our partnership's equity, make distributions to unitholders and make certain other restricted payments;
- make investments;
- modify the terms of the Convertible Debentures and certain other indebtedness, or prepay certain indebtedness;
- engage in transactions with affiliates;
- enter into certain hedging contracts;
- enter into certain burdensome agreements;
- change the nature of our business;
- enter into operating leases; and
- make certain amendments to our partnership agreement.

At December 31, 2012, our leverage ratio was 3.04 to 1.00 and the interest coverage ratio was 6.73 to 1.00. We were in compliance with all covenants of our credit agreement as of December 31, 2012.

As of December 31, 2012, the credit agreement permitted us to make quarterly distributions of available cash (as defined in our partnership agreement) to unitholders so long as: (i) no default or event of default exists under our credit agreement, (ii) we have, on a pro forma basis after giving effect to such distribution, at least $10.0 million of availability under the revolving loan facility, and (iii) our consolidated total leverage ratio, on a pro forma basis, would not be greater than 4.50 to 1.00.  In March 2013, the credit agreement was amended to, among other things, eliminate the requirement that our consolidated total leverage ratio not exceed 4.00 to 1.00. We are currently allowed to make distributions to our unitholders in accordance with these covenants; however, we will only make distributions to the extent we have sufficient cash from operations after establishment of cash reserves as determined by our general partner in accordance with our cash distribution policy, including the establishment of any reserves for the proper conduct of our business.

Each of the following is an event of default under our credit agreement:

- failure to pay any principal, interest, fees, expenses or other amounts when due;
- failure to meet the quarterly financial covenants;
- failure to observe any other agreement, obligation or covenant in the credit agreement or any related loan document, subject to cure periods for certain failures;
- the failure of any representation or warranty to be materially true and correct when made;
- our, or any of our subsidiaries', default under other indebtedness that exceeds a threshold amount;
- judgments against us or any of our subsidiaries, in excess of a threshold amount;
- certain material ERISA events involving us or any of our subsidiaries;
- bankruptcy or other insolvency events involving us or any of our subsidiaries; and
- a change of control (as defined in the credit agreement).

If an event of default relating to bankruptcy or other insolvency events occurs, all indebtedness under our credit agreement will immediately become due and payable. If any other event of default exists under our credit agreement, the lenders may accelerate the maturity of the obligations outstanding under our credit agreement and exercise other rights and remedies. In addition, if any event of default exists under our credit agreement, the lenders may commence foreclosure or other actions against the collateral.

If any default occurs under our credit agreement, or if we are unable to make any of the representations and warranties in our credit agreement, we will be unable to borrow funds or have letters of credit issued under our credit agreement.

It will constitute a change of control under our credit agreement if either Vitol or Charlesbank ceases to own, directly or indirectly, exactly 50% of the membership interests of our General Partner or if our General Partner ceases to be controlled by both Vitol and Charlesbank.

Contractual Obligations. A summary of our contractual cash obligations over the next several fiscal years, as of December 31, 2012, is as follows:

| | Payments Due by Period | | | | |
|---|---|---|---|---|---|
| Contractual Obligations | Total | Less than 1 year | 1-3 years | 4-5 years | More than 5 years |
| | (in millions) | | | | |
| Debt obligations(1) | $228.1 | $9.4 | $218.7 | $— | $— |
| Operating lease obligations | 16.6 | 5.5 | 7.9 | 2.2 | 1.0 |
| Related party throughput capacity agreement(2) | 3.0 | 2.1 | 0.9 | — | — |
| Non-compete agreement(3) | 0.2 | 0.1 | 0.1 | — | — |
| Employee contract obligations(4) | 0.5 | 0.3 | 0.2 | — | — |

(1) Represents required future principal repayments of borrowings of $211.0 million and variable rate interest payments of $17.0 million. At December 31, 2012, our borrowings had an interest rate of approximately 4.24%. This interest rate was used to calculate future interest payments. All amounts outstanding under our credit agreement mature in October 2014.

(2) Represents required future repayments of the Vitol prepaid fee related to the throughput capacity agreement for our Eagle North pipeline system of $2.7 million and interest of $0.3 million. This agreement matures at December 31, 2014.

(3) Represents required future payments under a non-compete agreement related to our acquisition of certain field services assets.

(4) Represents required future payments related to employment agreements with certain employees.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations is based upon our consolidated financial statements. We prepared these financial statements in conformity with generally accepted accounting principles in the United States. As such, we are required to make certain estimates, judgments and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the periods presented. We based our estimates on historical experience, available information and various other assumptions we believe to be reasonable under the circumstances. On an on-going basis, we evaluate our estimates; however, actual results may differ from these estimates under different assumptions or conditions. The accounting policies that we believe require our most difficult, subjective or complex judgments and are the most critical to our reporting of results of operations and financial position are as follows:

Use of Estimates. The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts and disclosure of contingencies. Management makes significant estimates including: (1) allowance for doubtful accounts receivable; (2) estimated useful lives of assets, which impacts depreciation; (3) estimated cash flows and fair values inherent in impairment tests; (4) accruals related to revenues and expenses; (5) the estimated fair value of financial instruments; and (6) liability and contingency accruals. Although management believes these estimates are reasonable, actual results could differ from these estimates.

Property, Plant and Equipment. Property, plant and equipment are recorded at cost. Expenditures for maintenance and repairs that do not add capacity or extend the useful life of an asset are expensed as incurred. The carrying value of the assets is based on estimates, assumptions and judgments relative to useful lives and salvage values. As assets are disposed of or sold, the cost and related accumulated depreciation are removed from the accounts, and any resulting gain or loss is included in operating income in the statements of operations.

We calculate depreciation using the straight-line method, based on estimated useful lives of our assets. These estimates are based on various factors including age (in the case of acquired assets), manufacturing specifications, technological advances and historical data concerning useful lives of similar assets. Uncertainties that impact these estimates include changes in laws and regulations relating to restoration and abandonment requirements, economic conditions and supply and demand in the area. When assets are put into service, we make estimates with respect to useful lives and salvage values that we believe to be reasonable. However, subsequent events could cause us to change our estimates, thus impacting the future calculation of depreciation and amortization. The estimated useful lives of our asset groups are as follows:

| Asset Group | Estimated Useful Lives (Years) |
|---|---|
| Land improvements | 10-20 |
| Pipelines and facilities | 5-30 |
| Storage and terminal facilities | 10-35 |
| Transportation equipment | 3-10 |
| Office property and equipment and other | 3-30 |

We capitalize certain costs directly related to the construction of assets, including interest and engineering costs. Upon disposition or retirement of property, plant and equipment, any gain or loss is included in other income in the statements of operations.

We have contractual obligations to perform dismantlement and removal activities in the event that some of our assets are abandoned. These obligations include varying levels of activity including completely removing the assets and returning the land to its original state. We have determined that the settlement dates related to the retirement obligations are indeterminate. The assets with indeterminate settlement dates have been in existence for many years and with regular maintenance will continue to be in service for many years to come. In addition, it is not possible to predict when demands for our services will cease, and we do not believe that such demand will cease for the foreseeable future. Accordingly, we believe the date when these assets will be abandoned is indeterminate. With no reasonably determinable abandonment date, we cannot reasonably estimate the fair value of the associated asset retirement obligations. We believe that if our asset retirement obligations were settled in the foreseeable future the potential cash flows that would be required to settle the obligations based on current costs are not material. We will record asset retirement obligations for these assets in the period in which sufficient information becomes available for us to reasonably determine the settlement dates.

Impairment of Long-lived Assets. Long-lived assets with recorded values that are not expected to be recovered through future cash flows are written-down to estimated fair value. Assets are tested for impairment when events or circumstances indicate that their carrying values may not be recoverable. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the carrying value exceeds the sum of the undiscounted cash flows, an impairment loss equal to the amount the carrying value exceeds the fair value of the asset is recognized. Fair value is generally determined from estimated discounted future net cash flows.

Recent Accounting Pronouncements

For information regarding recent accounting developments that may affect our future financial statements, see Note 21 to our Consolidated Financial Statements.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

We are exposed to market risk due to variable interest rates under our credit facility.

As of March 7, 2013 we had $200.0 million outstanding under our credit facility that was subject to a variable interest rate. Borrowings under our credit agreement bear interest, at our option, at either (i) the ABR (the highest of the administrative agent's prime rate, the federal funds rate plus 0.5%, or the one-month eurodollar rate (as defined in our credit agreement) plus 1.0%), plus an applicable margin that ranges from 3.0% to 3.5%, or (ii) the eurodollar rate plus an applicable margin that ranges from 4.0% to 4.5%, in each case depending on our consolidated total leverage ratio (as defined in our credit agreement).

During the twelve months ended December 31, 2012, our weighted average interest rate was and 5.48%, including interest under the throughput capacity agreement with Vitol related to our Eagle North pipeline system and the amortization of debt issuance costs, resulting in interest expense of approximately $11.7 million.

Changes in economic conditions could result in higher interest rates, thereby increasing our interest expense and reducing our funds available for capital investment, operations or distributions to our unitholders. Based on borrowings as of December 31, 2012 and the terms of our credit agreement, an increase or decrease of 100 basis points in the interest rate would result in increased or decreased annual interest expense of approximately $2.1 million.

Item 8. Financial Statements and Supplementary Data.

Our consolidated financial statements, together with the report of our independent registered public accounting firm PricewaterhouseCoopers LLP, are set forth on pages F-1 through F-29 of this report and are incorporated herein by reference.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

None.

Item 9A. Controls and Procedures

Evaluation of disclosure controls and procedures. Our General Partner's management, including the Chief Executive Officer and Chief Financial Officer of our General Partner, evaluated as of the end of the period covered by this report, the effectiveness of our disclosure controls and procedures as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of our General Partner concluded that our disclosure controls and procedures, as of December 31, 2012, were effective.

Management's Report on Internal Control Over Financial Reporting . Our General Partner's management is responsible for establishing and maintaining adequate internal control over financial reporting. Our General Partner's 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, our management concluded that our internal control over financial reporting was effective as of December 31, 2012. Our internal control over financial reporting as of December 31, 2012 has been audited by PricewaterhouseCoopers LLP, our independent registered public accounting firm, as stated in their report appearing on page F-2.

Changes in internal control over financial reporting. There were no changes in our internal control over financial reporting that occurred during the three months ended December 31, 2012 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

On March 8, 2013, the compensation committee of the Board approved a cash bonus plan whereby a bonus pool for all employees, including the NEOs, will be established. For a description of this plan and the targets established by the compensation committee, please see “Item 11. Executive Compensation-Compensation Discussion and Analysis-2013 Incentive Compensation.”

On March 11, 2013, we amended our crude oil storage services agreements with Vitol, effective as of March 1, 2013. For more information relating to these amendments, please see “Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Vitol Storage Agreements.”

## PART III

### Item 10. Directors, Executive Officers and Corporate Governance.

Our General Partner manages our operations and activities. Our General Partner is not elected by our unitholders and will not be subject to re-election on a regular basis in the future. The directors of our General Partner oversee our operations. Unitholders are not entitled to elect the directors of our General Partner or directly or indirectly participate in our management or operation. Our General Partner owes a limited fiduciary duty to our unitholders. Our General Partner will be 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 nonrecourse to it. Our General Partner, therefore, may cause us to incur indebtedness or other obligations that are nonrecourse to it.

#### Directors and Executive Officers

The Board currently consists of Michael R. Eisenson (affiliated with Charlesbank), Jon M. Biotti (affiliated with Charlesbank), Miguel A. (“Mike”) Loya (affiliated with Vitol), Francis Brenner (affiliated with Vitol), Duke R. Ligon (an independent director), Steven M. Bradshaw (an independent director) and John A. Shapiro (an independent director). Mr. Ligon serves as the Chairman of the Board, the chairman of the audit committee and a member of the compensation committee and the conflicts committee of the Board. Mr. Bradshaw serves as the chairman of the conflicts committee and a member of the compensation committee and the audit committee of the Board. Mr. Shapiro serves as the chairman of the compensation committee and a member of the conflicts committee and the audit committee of the Board.

On September 13, 2012, the Board appointed Mr. Mark A. Hurley as the Chief Executive Officer of our General Partner, effective September 20, 2012. Mr. Hurley replaced Mr. James C. Dyer, whose intended resignation was previously announced by the Partnership.

October 23, 2012, Mr. J. Michael Cockrell notified the Board of his resignation as President and Chief Operating Officer of our General Partner, effective as of October 31, 2012.

The following table shows information regarding the current directors and executive officers of our General Partner as of March 11, 2013.

| Name | Age | Position with Blueknight Energy Partners G.P., L.L.C. |
|---|---|---|
| Mark A. Hurley | 53 | Chief Executive Officer(1) |
| Alex G. Stallings | 45 | Chief Financial Officer and Secretary |
| James R. Griffin | 35 | Chief Accounting Officer |
| Jeffery A. Speer | 46 | Senior Vice President-Operations |
| Larry E. Hatley | 63 | Vice President - Transportation, Marketing and Operations |
| Duke R. Ligon | 71 | Director, Chairman of the Board and Audit Committee |
| Steven M. Bradshaw | 64 | Director, Chairman of the Conflicts Committee |
| John A. Shapiro | 61 | Director, Chairman of the Compensation Committee |
| Miguel A. (“Mike”) Loya | 57 | Director |

| | | |
|---|---|---|
| Michael R. Eisenson | 57 | Director |
| Jon M. Biotti | 44 | Director |
| Francis Brenner | 43 | Director |

(1) Mr. Hurley became the CEO on September 20, 2012, replacing Mr. James C. Dyer,, IV, who announced his intended resignation on January 6, 2012.

Our directors hold office until the earlier of their death, resignation, removal or disqualification or until their successors have been elected and qualified.  Officers serve at the discretion of the Board.  There are no family relationships among any of our directors or executive officers.

Mark A. Hurley became the Chief Executive Officer of our General Partner in September 2012. Mr. Hurley served as the Senior Vice President, Crude Oil and Offshore of Enterprise Products, LLC from 2010 to 2012, where he led the newly formed crude oil and offshore business segment. Mr. Hurley began his career at Shell, where he served from 1981 to 2009, most recently as President of Shell Pipeline Co., LP. Mr. Hurley received his bachelor of science in chemical engineering from North Carolina State University.

Alex G. Stallings has served as Chief Financial Officer and Secretary of our General Partner since March 2009.  Mr. Stallings served as Chief Accounting Officer and Secretary of our General Partner from February 2007 to March 2009.  Additionally, Mr. Stallings served as SemCorp's Chief Accounting Officer from September 2002 to July 2008. Prior to joining SemCorp, Mr. Stallings served as Chief Accounting Officer for Staffmark, Inc., a temporary staffing company where he was responsible for the public reporting and integration of numerous acquisitions during his tenure. Mr. Stallings also previously was an audit manager for the public accounting firm of Coopers & Lybrand, working in its Tulsa, Oklahoma office.  Mr. Stallings is a certified public accountant in the state of Oklahoma.

James R. Griffin has served as the Chief Accounting Officer of our General Partner since March 2009.  Mr. Griffin served as our General Partner's controller from May of 2007 to March 2009 and SemCorp's transactional services controller from September 2006 to May 2007.  Prior to joining SemCorp, Mr. Griffin served as an audit manager for the public accounting firm of PricewaterhouseCoopers LLP, working in its Tulsa, Oklahoma office.  Mr. Griffin is a certified public accountant in the state of Oklahoma.

Jeffery A. Speer has served as Senior Vice President-Operations of our General Partner since February 2010.  Previously, Mr. Speer had served as the Vice President of Operations for one of our subsidiaries since June 2009.  He served as Vice President of Operations for SemCorp's asphalt and emulsion business from June 2005 to June 2009.  Prior to joining SemCorp, Mr. Speer served as Vice President of Operations for Koch Industries, Inc. and had operational responsibility for Koch's crude oil and pipeline divisions in Oklahoma, Texas and Canada as well as Koch's agricultural and asphalt and emulsion businesses.  Mr. Speer has approximately twenty years experience in the energy industry and holds a Bachelor's degree in mechanical engineering from Kansas State University.

Larry E. Hatley has served as Vice President - Transportation Marketing and Operations of our General Partner since March 2010. Mr. Hatley served as a Regional Director of Marketing for Enterprise Products Partners LP from November 2009 until joining our General Partner. Previously he had served as a Director of Marketing for Teppco Partners LP from May 2009 until November 2009 and an asset manager for Teppco Partners LP from January 2006 until May 2009.

Duke R. Ligon has served as a director of our General Partner since October 2008.  He is an attorney and served as senior vice president and general counsel of Devon Energy Corporation from January 1997 until he retired in February 2007. Since February 2007, Mr. Ligon has served in the capacity of Strategic Advisor to Love's Travel Stops & Country Stores, Inc., based in Oklahoma City, and has previously acted as Executive Director of the Love's Entrepreneurship Center at Oklahoma City University. He is also a member of the Board of Directors of Post Rock Energy Corporation, Heritage Trust Company, Security State Bank, Panhandle Oil and Gas Inc. (NYSE: PHX), Pre-Paid Legal Services, Inc. (NYSE: PPD), SteelPath MLP Funds Trust and Vantage Drilling Company.  He also has 20% beneficial ownership in Security State Bank.  He was formerly on the Board of Directors of TransMontaigne Partners L.P. (NYSE: TLP) and TEPPCO Partners, L.P. (NYSE: TPP).  Mr. Ligon received an undergraduate degree in chemistry from Westminster College and a law degree from the University of Texas School of Law.  Mr. Ligon was selected to serve as a director on the Board due to his extensive business and leadership experience derived from his background as a director of various companies in the energy industry as well as his financial and legal expertise.

Steven M. Bradshaw has served as a director of our General Partner since November 2009. He has over 30 years of experience in the global logistics and transportation industry and currently serves as the Managing Director at Global Logistics Solutions. He is also currently serving as a director of Vantage Drilling Company. From 2005 to 2009, Mr. Bradshaw served as Vice President - Administration of Premium Drilling, Inc., an offshore drilling contractor that provides jack-up drilling services to the oil and gas industry in the United States and internationally. Previously, he served as Executive Vice President of Skaugen PetroTrans, Inc. from 2001 to 2003 and as President, Refined Products Division at Kirby Corporation, from 1992 to 1996. Mr. Bradshaw also served as an officer in the United States Navy and holds an MBA from Harvard University and a Bachelor’s degree in mathematics from the University of Missouri-Columbia. Mr. Bradshaw serves on the Board of Directors of Premium Drilling (Cayman) Ltd., a private company. Mr. Bradshaw was selected to serve as a director on the Board due to his business judgment and extensive industry knowledge and experience.

John A. Shapiro has served as a director of our General Partner since November 2009. Mr. Shapiro retired as an officer at Morgan Stanley & Co. where he had served for more than 24 years in various capacities, most recently as Global Head of Commodities. While an officer at Morgan Stanley, Mr. Shapiro participated in the successful acquisitions of TransMontaigne Inc. and Heidmar Inc. and served as a member of the board of directors of both companies. Prior to joining Morgan Stanley & Co., Mr. Shapiro worked for Conoco, Inc. and New England Merchants National Bank. Mr. Shapiro has been a lecturer at Princeton University, Harvard University School of Government, HEC Business School (Paris, France) and Oxford University Energy Program (Oxford, UK). In addition, he serves on the board of directors of Blue Wolf Magnolia Holdings and Citymeals-on-Wheels and holds an MBA from Harvard University and a Bachelor's degree in economics from Princeton University. Mr. Shapiro was selected to serve as a director on the Board due to his valuable financial expertise and extensive industry experience developed through his work at Morgan Stanley & Co. and by serving as a director of other energy companies.

Miguel A. ("Mike") Loya has served as a director of our General Partner since November 2009 and was appointed to the Board in connection with his affiliation with Vitol, which, together with Charlesbank, controls our General Partner. Mr. Loya has served as a director of Vitol since 1996 and as the President of Vitol, Inc. since 1999. As such, he is Vitol's senior shareholder responsible for the management of the Vitol Group's trading activities, companies and assets in North and South America. Previously, Mr. Loya has enjoyed positions with Transworld Oil U.S.A., Inc., Tenneco Inc. and Exxon Mobil Corporation. He currently serves on the board of OTC Global Holdings Co., Yes Prep Public Schools and Pilot Travel Centers LLC. Mr. Loya holds an MBA from Harvard University and a Bachelor's degree in mechanical engineering from the University of Texas at El Paso. Mr. Loya was selected to serve as a director on the Board due to his affiliation with Vitol, his knowledge of the energy industry and his financial and business expertise.

Michael R. Eisenson has served as a director of our General Partner since November 2010 and was appointed to the Board in connection with his affiliation with Charlesbank, which, together with Vitol, controls our General Partner. Mr. Eisenson is a Managing Director and Chief Executive Officer of Charlesbank, which is a Boston-based private equity firm. Prior to co-founding Charlesbank in 1998, Mr. Eisenson was the President of Harvard Private Capital Group. He began his tenure at Harvard Management Company in 1986 as Managing Director. Before joining Harvard Management Company, Mr. Eisenson was with The Boston Consulting Group, a corporate strategy consulting firm. Mr. Eisenson serves on the board of directors of CIFC Corp., Montpelier Re, Penske Auto Group and several privately held Charlesbank portfolio companies. Mr. Eisenson was also a board member of Regency Gas Services, representing Charlesbank which was Regency's founding equity investor. He is a graduate of Williams College, with a Bachelor's degree in economics, and holds an MBA and a Juris Doctorate degree from Yale University. Mr. Eisenson was selected to serve as a director on the Board due to his affiliation with Charlesbank, his knowledge of the energy industry and his financial and business expertise.

Jon M. Biotti has served as a director of our General Partner since November 2010 and was appointed to the Board in connection with his affiliation with Charlesbank, which, together with Vitol, controls our General Partner. Mr. Biotti is a Managing Director of Charlesbank, which he joined in 1998 after graduating from Harvard Business School where he was an entrepreneurial studies fellow. Mr. Biotti also worked as a banking associate at Brown Brothers Harriman & Co. Mr. Biotti serves on the board of directors of several privately held Charlesbank portfolio companies. Mr. Biotti was also a board member of Regency Gas Services, representing Charlesbank which was Regency's founding equity investor. Educated at Harvard, Mr. Biotti received a Bachelor's degree in government and sociology, an MBA and an MA in public administration. Mr. Biotti was selected to serve as a director on the Board due to his affiliation with Charlesbank, his knowledge of the energy industry and his financial and business expertise.

Francis Brenner has served as a director of our General Partner since September 2012. Mr. Brenner has served as the Investments Director for the Americas for Vitol Inc. since 2010. Between 2001 and 2010, Mr. Brenner was with

Morgan Stanley, most recently as an Executive Director in the Morgan Stanley Commodities Group. Prior to joining Morgan Stanley, Mr. Brenner was involved in the design and construction of utility infrastructure at Tyco International. Mr. Brenner holds an MBA from the University of Michigan and a Bachelors degree in engineering from the University of Wisconsin-Platteville. Mr. Brenner was selected to serve as a director on the Board due to his affiliation with Vitol, his knowledge of the energy business and his financial and business expertise.

Independence of Directors

We were relisted on the Nasdaq Global Market effective May 16, 2011. Our General Partner currently has seven directors, three of whom (Messrs. Bradshaw, Ligon and Shapiro) are “independent” as defined under the independence standards established by Nasdaq. Nasdaq’s independence definition includes a series of objective tests, including that the director is not an employee of the company and has not engaged in various types of business dealings with the company. In addition, the Board 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. Nasdaq does not require a listed limited partnership like us to have a majority of independent directors on the Board or to establish a nominating committee.

In addition, the members of the audit committee also each qualify as "independent" under special 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. John A. Shapiro 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 experience and understanding with respect to certain accounting and auditing matters. The designation does not impose any duties, obligations or liability that are greater than are generally imposed on a member of the audit committee and board of directors, and the designation of a director 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.

Board Leadership Structure and Risk Oversight

The Chief Executive Officer and Chairman of the Board positions of our General Partner are held by separate individuals in recognition of the differences between the two roles. We have taken this position to achieve an appropriate balance with regard to our strategic direction, oversight of management, unitholder interests and director independence. Our General Partner's Chief Executive Officer is responsible for setting our strategic direction and overseeing our day to day performance. Our General Partner's Chairman of the Board is an independent director who provides guidance to the Chief Executive Officer and sets the agenda for and presides over Board meetings.

Our Board is engaged in the oversight of risk through regular updates from our management team regarding those risks confronting us, the actions and strategies necessary to mitigate those risks and the status and effectiveness of those actions and strategies. These regular updates are provided at meetings of the Board and the audit committee as well as other meetings with the Chairman of the Board, the Chief Executive Officer and other members of our General Partner's management team.

Board Committees

We have standing conflicts, audit and compensation committees of the Board. Each member of the audit, compensation and conflicts committees is an independent director in accordance with Nasdaq and applicable securities laws. Each of the audit, compensation and conflicts committees has a written charter approved by the Board. The written charter for each of these committees is available on our web site at www.bkep.com under the "Investors-Corporate Governance" section. We will also provide a copy of any of our committee charters to any of our unitholders without charge upon written request to the attention of Investor Relations at 6120 South Yale, Suite 500, Tulsa, Oklahoma 74136. The current members of the audit, compensation and conflicts committees of the Board and a brief description of the functions performed by each committee are set forth below.

Conflicts Committee. The members of the conflicts committee are Messrs. Bradshaw (chairman), Ligon and Shapiro. 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 conflicts committee may retain independent legal and financial advisors to assist it in its evaluation of a transaction. 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 any national securities exchange upon which our common units are traded and the SEC. 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. The members of the audit committee are Messrs. Bradshaw, Ligon (chairman) and Shapiro. The primary responsibilities of the audit committee are to assist the Board 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.

For information regarding our audit committee financial expert, see "- Independence of Directors" above.

Compensation Committee. The members of the compensation committee are Messrs. Bradshaw, Ligon and Shapiro (chairman). 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 as well as administer the General Partner's Long-Term Incentive Plan.

Code of Ethics and Business Conduct

Our General Partner has adopted a Code of Business Conduct and Ethics applicable to all of our General Partner's employees, 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 Business Conduct and Ethics 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 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 Business Conduct and Ethics is publicly available under the "Investors - Corporate Governance" section of our web site at www.bkep.com. The information contained on, or connected to, our web site is not incorporated by reference into this annual report on Form 10-K and should not be considered part of this or any other report that we file with, or furnish to, the SEC. We will also provide a copy of the Code of Business Conduct and Ethics to any of our unitholders without charge upon written request to the attention of Investor Relations at 6120 South Yale, Suite 500, Tulsa, Oklahoma 74136. If any substantive amendments are made to the Code of Business Conduct and Ethics 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 web site or in a current report on Form 8-K.

Section 16(a) Beneficial Ownership Reporting Compliance

Based solely upon a review of Forms 3, 4 and 5 (and any amendments thereto) furnished to us, we believe that no directors, officers, beneficial owners of more than 10% of any class of the Partnership's securities or any other person subject to Section 16 of the Exchange Act failed to file reports required by Section 16(a) of the Exchange Act during the year ended December 31, 2012. Due to administrative errors, Forms 5 were filed late on February 14, 2013 on behalf of Francis Brenner regarding his appointment to the Board on September 20, 2012 and on behalf of Mark A. Hurley regarding his appointment as Chief Executive Officer and award of phantom units on September 20, 2012.

Reimbursement of Expenses of our General Partner

Pursuant to our partnership agreement, our General Partner and its affiliates are entitled to receive reimbursement for the payment of expenses related to our operations and for the provision of various general and administrative services for our benefit.

Item 11. Executive Compensation.

Compensation Discussion and Analysis

Throughout this section, each person who served as the Principal Executive Officer ("PEO") during 2012, each person who served as the Principal Financial Officer ("PFO") during 2012 and the three most highly compensated executive officers other than the PEO and PFO serving at December 31, 2012 and up to two additional individuals for whom disclosure would have been provided but for the fact that the individual was not serving as an executive officer at December 31, 2012 are referred to as the Named Executive Officers ("NEOs"). The NEOs include the following:

- Mark A. Hurley, Chief Executive Officer;
- Alex G. Stallings, Chief Financial Officer and Secretary;
- James R. Griffin, Chief Accounting Officer;

- Jeffery A. Speer, Senior Vice President - Operations;
- Larry E. Hatley, Vice President - Transportation, Marketing and Operations;
- James C. Dyer, IV, Chief Executive Officer until September 20, 2012;
- J. Michael Cockrell, President and Chief Operating Officer until October 31, 2012; and
- Jerry A. Parsons, Executive Vice President - Products until March 9, 2012.

Throughout this section we refer to Messrs. Hurley, Stallings, Griffin, Speer and Hatley as our “current NEOs.”

As is the case with many publicly traded partnerships, we have not historically directly employed any persons responsible for managing or operating us or for providing services relating to day-to-day business affairs.  Our General Partner manages our operations and activities, and its Board and officers make decisions on our behalf. With the exception of Mr. Dyer, as described below, the compensation for the NEOs for services rendered to us is determined by the compensation committee of our General Partner. Mr. Dyer's employment with our General Partner was ended effective September 20, 2012, upon the employment of Mr. Hurley as his successor. Mr. Cockrell's employment with our General Partner was ended effective October 31, 2012. Mr. Parsons' employment with our General Partner was ended effective March 9, 2012.

Mr. Dyer was an officer of Vitol. In this capacity, he performed services for us as well as for Vitol and its other affiliates. Mr. Dyer received his compensation solely from Vitol. The compensation committee had no role in determining the base salary and short-term and long-term incentive compensation paid to him by Vitol. We did not directly or indirectly reimburse Vitol for the costs of compensation of Mr. Dyer. Throughout this section we refer to our NEOs other than Mr. Dyer as our "compensated NEOs."

Compensation Methodology. The compensation committee of the Board seeks to provide a total compensation package designed to drive performance and reward contributions in support of our business strategies and to attract, motivate and retain high quality talent with the skills and competencies required by us. Our compensation committee annually examines the compensation practices of certain of our peer companies, which includes American Midstream Partners, LP, Crestwood Midstream Partners LP, Genesis Energy, LP, Holly Energy Partners, L.P., Inergy Midstream, L.P., Niska Gas Storage Partners LLC, Oiltanking Partners, L.P., PAA Natural Gas Storage, L.P., Rose Rock Midstream, L.P., Tesoro Logistics LP and Transmontaigne Partners L.P. The compensation committee may review and, in certain cases, participate in, various relevant compensation surveys and consult with compensation consultants with respect to determining compensation for the NEOs.

In 2012, the compensation committee of the Board engaged Frost HR Consulting ("Frost") as its independent compensation consultant to advise the compensation committee regarding potential compensation programs and methodologies applicable to the named executive officers and other employees of our General Partner. In its consultation role, Frost was tasked with conducting an assessment of our peer group, benchmarking the compensation of our current NEOs against our peer group and advising the compensation committee with respect to pay practices of our peer group. Frost's work for the compensation committee did not raise any conflicts of interest in 2012.

Elements of Compensation. Historically, the primary elements of our General Partner's compensation program have been a combination of annual cash and long-term equity-based compensation, and the principal elements of compensation for the compensated NEOs were the following:

- base salary;
- discretionary bonus awards;
- long-term incentive plan awards; and
- other benefits.

The compensation committee reviews and makes recommendations regarding the mix of compensation, both among short and long-term compensation and cash and non-cash compensation, to establish structures that it believes are appropriate for each of the compensated named executive officers. We believe that the mix of base salary, discretionary bonus awards, awards under the long-term incentive plan and other benefits fit our overall compensation objectives. We believe this mix of compensation provides competitive compensation opportunities to align and drive employee performance in support of our business strategies and to attract, motivate and retain high quality talent with the skills and competencies that we require.

Base Salary. Historically, our General Partner's compensation committee established base salaries for the compensated NEOs based on various factors including the amounts it considered necessary to attract and retain the highest quality executives, the responsibilities of the NEOs and market data including publicly available market data for the peer companies listed above as reported in their filings with the SEC.

Each of the compensated NEOs other than Mr. Speer has entered into employment agreements with a subsidiary of our General Partner. The employment agreements for our compensated NEOs provide for, or in the case of Messrs. Cockrell and Parsons, provided for, an annual base salary of $425,000, $300,000, $210,000, $190,000, $282,000 and $250,000 for Messrs. Hurley, Stallings, Griffin, Hatley, Cockrell and Parsons, respectively, and in 2012, Mr. Speer's base salary was $210,000. These base salary amounts were originally determined based upon the scope of each executive's responsibilities that were commensurate with such executive's position as well as the added responsibilities the executives have that were typical of executives in publicly traded partnerships, taking into account competitive market compensation paid by similar companies for comparable positions. In addition, the base salary amounts payable to Messrs. Hurley, Speer, Hatley, Cockrell and Parsons were determined, in part, by the base salary amount and other benefits each such individual received prior to joining our General

Partner's management team. In March 2012, our General Partner's compensation committee decided to leave base salaries unchanged for the compensated NEOs except for that of Mr. Speer, which increased from $208,000 to $210,000, and that of Mr. Hatley, which increased from $185,000 to $190,000. In March 2013, our General Partner's compensation committee decided to increase the base salaries of Messrs. Stallings, Speer, Hatley and Griffin to $306,000, $214,000, $192,456 and $214,000, respectively.

Discretionary Bonus Awards. Our General Partner's compensation committee may also award discretionary bonus awards to the compensated NEOs. Our General Partner may use discretionary bonus awards for achieving financial and operational goals and for achieving individual performance objectives.

On July 1, 2009, the compensation committee adopted the 2009 Cash Bonus Plan. This plan provided for incentive payments to certain of our NEOs based upon the overall financial performance measured by EBITDA of our asphalt and/or crude oil operations. In addition, under the 2009 Cash Bonus Plan, the compensation committee made discretionary incentive payments based upon the performance of such NEO. We made payments to Messrs. Stallings, Parsons and Griffin of $375,000, $300,000 and $157,500, respectively, under the 2009 Cash Bonus Plan ($75,000, $50,000, and $31,500, respectively, of which was paid in 2010). Messrs. Hurley, Speer, Hatley and Cockrell were not part of our General Partner's management team at the time of the adoption of the 2009 Cash Bonus Plan.

During March 2011, the compensation committee awarded discretionary bonuses of $175,000, $125,000, $150,000, $100,000, $50,000 and $75,000 to each of Messrs. Cockrell, Stallings, Parsons, Speer, Hatley and Griffin, respectively, relating to our results of operations in 2010. Please see "—2010 Incentive Compensation" for a discussion of these discretionary bonuses.

During March 2012, the compensation committee awarded discretionary bonuses of $175,000, $135,000, $125,000, $110,000, $100,000 and $80,000 to each of Messrs. Cockrell, Stallings, Parsons, Speer, Hatley and Griffin, respectively, relating to our results of operations in 2011. Please see "-2011 Incentive Compensation" for a discussion of these discretionary bonuses.

During March 2013, the compensation committee awarded discretionary bonuses of $425,000, $140,000, $115,000, $75,000 and $84,000 to each of Messrs. Hurley, Stallings, Speer, Hatley and Griffin, respectively, relating to our results of operations in 2012. Please see "-2012 Incentive Compensation" for a discussion of these discretionary bonuses.

Long-Term Incentive Plan Awards. Our General Partner has adopted the Long-Term Incentive Plan for employees, consultants and directors of our General Partner and its affiliates who perform services for us. Each of the compensated NEOs is, or in the case of Messrs. Cockrell and Parsons, was, eligible to participate in the Long-Term Incentive Plan. The Long-Term Incentive Plan provides for the grant of unit awards, restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights and substitute awards. For a more detailed description of our Long-Term Incentive Plan, please see "-Long-Term Incentive Plan."

Our General Partner's compensation committee did not make any awards to our NEOs under the Long-Term Incentive Plan during 2010. During March 2011, the compensation committee made awards of phantom units to our compensated NEO's of 30,000 units, 15,000 units, 10,000 units, 15,000 units, 8,500 units and 10,000 units to Messrs. Cockrell, Stallings, Parsons and Speer, Hatley and Griffin, respectively, relating to our results of operations in 2010. The awards vest on January 1, 2014. These phantom units contain distribution equivalent rights that entitle the holder of such units to receive a cash payment equal to the amount of any ordinary quarterly cash distribution paid to our common unitholders. Please see "-2010 Incentive Compensation" for a discussion of these awards.

During March 2012, the compensation committee made awards of phantom units to our compensated NEO's of 40,000 units, 20,000 units, 20,000 units, 20,000 units and 12,000 units to Messrs. Cockrell, Stallings, Speer, Hatley and Griffin, respectively, relating to our results of operations in 2011. The awards vest on January 1, 2015. These phantom units contain distribution equivalent rights that entitle the holder of such units to receive a cash payment equal to the amount of any ordinary quarterly cash distribution paid to our common unitholders. Please see "-2011 Incentive Compensation" for a discussion of these awards.

Messrs. Parsons and Cockrell's employment with our General Partner was ended on March 9, 2012 and October 31, 2012, respectively, and, accordingly, their phantom units vested at such time.

During September 2012, in connection with his appointment as our Chief Executive Officer, the compensation committee made an award of 500,000 phantom units to Mr. Hurley. The award vests ratably in 20% increments on each of September 20, 2013, 2014, 2015, 2016 and 2017, respectively. These phantom units do not contain distribution equivalent rights

During March 2013, the compensation committee made awards of phantom units to our current NEOs of 16,770 units, 16,149 units, 9,466 units and 9,317 units to Messrs. Stallings, Speer, Hatley and Griffin, respectively, relating to our results of operations in 2012. The awards vest on January 1, 2016. These phantom units contain distribution equivalent rights that entitle the holder of such units to receive a cash payment equal to the amount of any ordinary quarterly cash distribution paid to our common unitholders. Please see "-2012 Incentive Compensation" for a discussion of these awards.

Other Benefits. The employment agreements entered into by each of the compensated NEOs other than Mr. Speer with our General Partner provide that such NEO is eligible to participate in any employee benefit plans maintained by our General Partner during the term of his employment with the General Partner. During 2010, 2011 and 2012, our General Partner maintained an employee health insurance plan and an Exec-U-Care plan under which our officers were reimbursed for certain co-pays and deductibles for medical expenses in addition to the Long-Term Incentive Plan described above. In addition, the employment agreements provide that each compensated NEO is entitled to reimbursement for out-of-pocket expenses incurred while performing his duties under the employment agreement.

In addition, we currently provide car allowances and reimbursement of certain deductibles and co-payments for medical expenses to our current NEOs.

2010 Incentive Compensation. During 2010, we continued to face uncertainty in our business and our ability to continue as a going concern. Our management team focused its efforts on stabilizing our business and operations, continuing to replace the revenue previously derived from services provided to SemCorp with revenues from third parties, transitioning services provided by SemCorp to us, managing litigation and refinancing our prior credit facility. Because our business had not yet been stabilized, the compensation committee did not adopt a specific plan for 2010 or set targets for 2010 compensation. Instead, the compensation committee and the Board set aside certain amounts in the 2010 budget that could be used for discretionary bonuses if the compensation committee determined to award such bonuses after a review of our partnership's performance during 2010. The committee never formally adopted a specific target as it wanted to keep full discretion of whether to award any bonuses related to performance during 2010.

During March 2011, our General Partner's chief executive officer proposed to the compensation committee that each compensated NEO receive (i) a discretionary bonus award relating to our results of operations in 2010 as follows: $175,000, $125,000, $150,000, $100,000, $50,000 and $75,000 for Messrs. Cockrell, Stallings, Parsons, Speer, Hatley and Griffin, respectively, and (ii) awards of phantom units relating to our results of operations for 2010 as follows: 30,000 units, 15,000 units, 10,000 units, 15,000 units, 8,500 units and 10,000 units to Messrs. Cockrell, Stallings, Parsons, Speer, Hatley and Griffin, respectively. The compensation committee agreed with these recommendations and on March 11, 2011 made discretionary bonus awards and phantom unit grants in accordance with such recommendations. The discretionary bonus awards were paid during March 2011. The compensation committee considered the items of emphasis for our NEOs outlined in the prior paragraph as well as the performance of the individual compensated NEO in determining to make such awards.

In addition, during 2010, Messrs. Cockrell and Hatley received payments upon the Charlesbank Change of Control. Please see "-Potential Payments Upon Change of Control or Termination" below for a discussion of these payment amounts.

2011 Incentive Compensation. Due to continued uncertainty in our business and uncertainty arising out of our ability to complete the transactions contemplated by the Global Transaction Agreement and conclude certain litigation, the compensation committee did not adopt a specific plan for 2011 or set targets for 2011 compensation. Instead, the compensation committee and the Board set aside certain amounts in the 2011 budget that could be used for discretionary bonuses if the compensation committee determined to award such bonuses after a review of our partnership's performance during 2011. The compensation committee never formally adopted a specific target as it wanted to keep full discretion of whether to award any bonuses related to performance during 2011.

During March 2012, our General Partner's chief executive officer proposed to the compensation committee that each compensated NEO receive (i) a discretionary bonus award relating to our results of operations in 2011 as follows: $175,000, $135,000, $125,000, $110,000, $100,000 and $80,000 for Messrs. Cockrell, Stallings, Parsons, Speer, Hatley and Griffin, respectively, and (ii) awards of phantom units relating to our results of operations for 2011 as follows: 40,000 units, 20,000 units, 20,000 units, 20,000 units and 12,000 units to Messrs. Cockrell, Stallings, Speer, Hatley and Griffin, respectively. The compensation committee agreed with these recommendations and on March 7, 2012 made discretionary bonus awards and phantom unit grants in accordance with such recommendations. The discretionary bonus awards were paid during March 2012. The compensation committee considered the items of emphasis for our NEOs outlined in the prior paragraph as well as the performance of the individual compensated NEO in determining to make such awards.

2012 Incentive Compensation. Due to the timing of the compensation consultation provided by Frost and the retirement of our former CEO, the compensation committee did not adopt a specific plan for 2012 or set targets for 2012 compensation. Instead, the compensation committee and the Board set aside certain amounts in the 2012 budget that could be used for discretionary bonuses if the compensation committee determined to award such bonuses after a review of our partnership's performance during 2012. The compensation committee never formally adopted a specific target as it wanted to keep full discretion of whether to award any bonuses related to performance during 2012.

During March 2013, our General Partner’s chief executive officer proposed to the compensation committee that each of our current compensated NEOs receive (i) a discretionary bonus award relating to our results of operations in 2012 as follows: $140,000, $115,000, $75,000 and $84,000 for Messrs. Stallings, Speer, Hatley and Griffin, respectively, and (ii) awards of phantom units relating to our results of operations for 2012 as follows: 16,770 units, 16,149 units, 9,466 units and 9,317 units to Messrs. Stallings, Speer, Hatley and Griffin, respectively. The compensation committee agreed with these recommendations and on March 8, 2013 made discretionary bonus awards and phantom unit grants in accordance with such recommendations. The discretionary bonus awards will be paid during March 2013. The compensation committee considered the items of emphasis for our NEOs outlined in the prior paragraph as well as the performance of the individual compensated NEO in determining to make such awards.

Please see “—Employment Agreement of Mr. Hurley” for a discussion of 2012 incentive compensation paid to Mr. Hurley.

2013 Incentive Compensation. For 2013, the Board has approved a cash bonus plan whereby a bonus pool for all employees, including the NEOs, will be established. The bonus pool will equal a percentage of a performance metric equal to cash flow generated prior to distributions, incentive compensation and reserves established by our General Partner (which has been set at approximately $48 million for 2013). Between 50% and 75% of the bonus pool will be funded based on the achievement of this performance metric (with up to an additional 15% being contributed based on achieving results in excess of this performance metric), with an additional 15% of the bonus pool based on the achievement of company wide goals and an additional 10% of the bonus pool based on the achievement of environmental, health and safety targets. Individual awards (which, as in prior years, are expected to be paid in a combination of cash bonuses and equity compensation) will be determined by the compensation committee in its discretion based on individual performance, exceptional service to the Partnership, challenges and opportunities not reasonably foreseeable at the beginning of the year, internal equities and external competition or opportunities.

Compensation Mix. Our General Partner’s compensation committee determines the mix of compensation, both among short and long-term compensation and cash and non-cash compensation, to establish structures that it believes are appropriate for each of the compensated NEOs.

Role of Executive Officers in Executive Compensation. Our General Partner’s compensation committee determines the compensation of the compensated NEOs. Our General Partner’s former chief executive officer, Mr. Dyer, previously assisted the compensation committee in reviewing its compensation methodology. Mr. Dyer also made recommendations to the compensation committee for the awards of phantom units and discretionary bonuses to be paid to our compensated NEOs relating to our results of operations in 2010 and 2011. Our General Partner's chief executive officer, Mr. Hurley made recommendations to the compensation committee for the awards of phantom units and discretionary bonuses to be paid to our compensated NEOs relating to our results of operations in 2012. Mr. Hurley does not make any recommendations regarding his personal compensation. In addition, the employment agreements entered into by Messrs. Stallings and Parsons were originally approved by the management committee of SemCorp’s general partner pursuant to its limited liability company agreement.

Employment Agreements. As indicated above, each of the compensated NEOs except Mr. Speer has entered into an employment agreement with our General Partner.

Employment Agreement of Mr. Hurley. Pursuant to Mr. Hurley's employment agreement, Mr. Hurley will be paid an initial annual base salary of $425,000. Mr. Hurley's employment agreement has an initial five year term that will automatically be extended for one year periods unless either party gives 90 days advance notice. Mr. Hurley received a sign-on bonus of $100,000 that was paid in October 2012. Additionally, Mr. Hurley is entitled to a $425,000 bonus during his first year of employment. Mr Hurley also received 500,000 non-participating phantom units in September 2012 under the General Partner's Long-Term Incentive Plan, which vest ratably over five years pursuant to the Phantom Unit Agreement he entered into with the General Partner. The Employment Agreement also provides that Mr. Hurley is eligible to participate in any employee benefit plans maintained by the General Partner and is entitled to reimbursement for certain out-of-pocket expenses. Mr.Hurley has agreed not to disclose any confidential information obtained by him while employed under the Employment Agreement and has agreed to a one year non-solicitation covenant.

Except in the event of termination for Cause (as defined below), termination by Mr. Hurley other than for Good Reason (as defined below), termination after the expiration of the term of Mr. Hurley's employment agreement or termination due to death or disability, Mr. Hurley's employment agreement provides for payment of any unpaid base salary and vested benefits under any incentive plans, a lump sum payment equal to twelve months of base salary, and Mr. Hurley will also be entitled to continued participation in our General Partner's welfare benefit programs for a period of eighteen months following termination. Based upon Mr. Hurley's current base salary, the maximum amount of the lump sum severance payment would be $425,000, in addition to continued participation in the General Partner's welfare benefit programs and the amounts of unpaid base salary and benefits under any incentive plans.

"Cause" means (i) conviction of the officer by a court of competent jurisdiction of any felony or a crime involving moral turpitude; (ii) the officer's willful and intentional failure or willful intentional refusal to follow reasonable and lawful instructions of the Board; (iii) the officer's material breach or default in the performance of his obligations under the Employment Agreement; or (iv) the officer's act of misappropriation, embezzlement, intentional fraud or similar conduct involving the General Partner.

"Good Reason" means (i) a material reduction in the officer's base salary; (ii) a material diminution of the officer's duties, authority or responsibilities as in effect immediately prior to such diminution; or (iii) the relocation of the officer's principal work location to a location more than 150 miles from its current location.

"Change of Control" means any of the following events: (i) Charlesbank Capital Partners, LLC and/or Vitol Holding B.V., or their respective affiliates, cease to be the beneficial owner, on a combined basis, of 50% or more of the combined voting power of the equity interests in the General Partner; (ii) the Partnership's limited partners approve, in one or a series of transactions, a plan of complete liquidation of the Partnership; (iii) the sale or other disposition by either the General Partner or the Partnership of all or substantially all of the assets of the General Partner or the Partnership in one or more transactions to any person other than the General Partner and its affiliates; or (iv) a transaction resulting in a person other than the General Partner or an affiliate of the General Partner being the Partnership's general partner.

In October 2012, Vitol and Charlesbank, the owners of Blueknight GP Holding, LLC ("HoldCo"), the owner of our General Partner, admitted Mr. Hurley as a member of HoldCo. In connection with his admission as a member of HoldCo, Mr. Hurley was issued a non-voting economic interest in HoldCo (the "Profits Interest"). Mr. Hurley's Profits Interest in HoldCo will vest in 20% increments on each of October 4, 2013, 2014, 2015, 2016 and 2017 and entitle Mr. Hurley, to the extent vested, to (i) 2% of the total amount of proceeds and/or distributions in excess of $100,000,000 received by HoldCo in connection with a transaction resulting in a change of control of us, and (ii) 2% of the portion of any interim quarterly distribution received by HoldCo in excess of $1,250,000. As of December 31, 2012 no Profits Interest is vested.

Although the entire economic burden of the Profits Interest, which is equity classified, is borne solely by HoldCo and does not impact our cash or units outstanding, the intent of the Profits Interest is to provide a performance incentive and encourage retention of Mr. Hurley. Therefore, we recognize the grant date fair value of the Profits Interest as compensation expense over the service period. The expense is also reflected as a capital contribution and thus, results in a corresponding credit to Partners' Capital in our Consolidated Financial Statements. Less than $0.1 million was recognized as expense in 2012.

Employment Agreement of Messrs. Stallings, Griffin and Parsons. The employment agreement entered into by each of Messrs. Stallings, Griffin and Parsons has a term of two years that will automatically be extended for one year periods unless either party gives 90 days advance notice. This employment agreement provides for the initial annual base salary described above. As described above, Mr. Stallings' base salary was increased in March 2009 in connection with the realignment of our executive officers. In addition, each of the compensated NEOs is eligible for discretionary bonus awards and long-term incentives which may be made from time to time in the sole discretion of the Board. The employment agreements also provide that Messrs. Stallings, Griffin and Parsons are eligible to participate in any employee benefit plans maintained by our General Partner during the term of his employment with the General Partner and for up to 12 months thereafter and are entitled to reimbursement for certain out-of-pocket expenses.

Pursuant to the employment agreements, each of Messrs. Stallings, Griffin and Parsons has agreed not to disclose any confidential information obtained by him while employed under the agreement. In addition, each employment agreement contains payment obligations that may be triggered by a termination after a change of control as defined therein. See "- Potential Payments Upon Change of Control or Termination."

Under the employment agreement entered into with Messrs. Stallings, Griffin and Parsons, our General Partner may be required to pay certain amounts upon a change of control of us or our General Partner or upon the termination of the executive officer in certain circumstances. Except in the event of termination for Cause, termination by the NEO other than for Good

Reason, or termination after the expiration of the term of the employment agreement, the employment agreements provides for payment of any unpaid base salary and vested benefits under any incentive plans, a lump sum payment equal to twelve months of base salary and continued participation in our General Partner's welfare benefit programs for the longer of the remainder of the term of the employment agreement or one year after termination. Mr. Parsons' employment with our General Partner was ended effective March 9, 2012. Accordingly, Mr. Parsons received a lump sum payment of $250,000, which was equal to twelve months of his base salary, and automatic vesting of 10,000 phantom units he was granted in March 2011 pursuant to our General Partner's Long-Term Incentive Plan.

The employment agreements also provide that if, within one year after a change of control occurs, the NEO is terminated by our General Partner without Cause or such individual terminates the agreement for Good Reason, he will be entitled to payment of any unpaid base salary and vested benefits under any incentive plans, a lump sum payment equal to 24 months of base salary and continued participation in our General Partner's welfare benefit programs for the longer of the remainder of the term of the employment agreement or one year after termination.

For purposes of the employment agreements with Messrs. Stallings, Griffin and Parsons:

"Cause" means (i) conviction of the executive officer by a court of competent jurisdiction of any felony or a crime involving moral turpitude; (ii) the executive officer's willful and intentional failure or willful intentional refusal to follow reasonable and lawful instructions of the Board; (iii) the executive officer's material breach or default in the performance of his obligations under the employment agreement; or (iv) the executive officer's act of misappropriation, embezzlement, intentional fraud or similar conduct involving our General Partner.

"Good Reason" means (i) a material reduction in the executive officer's base salary; (ii) a material diminution of the executive officer's duties, authority or responsibilities as in effect immediately prior to such diminution; or (iii) the relocation of such individual's principal work location to a location more than 50 miles from its current location.

"Change of Control" means any of the following events: (i) any person or group other than SemCorp and its affiliates shall become the beneficial owner, by way of merger, consolidation, recapitalization, reorganization or otherwise, of 50% or more of the combined voting power of the equity interests in us or our General Partner; (ii) our limited partners approve, in one or a series of transactions, a plan of complete liquidation of us; (iii) the sale or other disposition by either our General Partner or us of all or substantially all of the assets of our General Partner or us in one or more transactions to any person other than our General Partner and its affiliates; or (iv) a transaction resulting in a person other than our General Partner or an affiliate of our General Partner being the general partner of the partnership.

Employment Agreement of Messrs. Cockrell and Hatley. Mr. Cockrell entered into his employment agreement in December of 2009 with a term of five years. Mr. Hatley entered into his employment agreement in March 2010 with a term of three years. These employment agreements provide for the initial base salaries described above. In addition, each of the employment agreements provide that, during the period from 2010 to 2013, Messrs. Cockrell and Hatley are entitled to certain deferred payments as compensation for long-term incentive awards which such individual forfeited upon leaving his prior employer. The amount of such deferred payments totaled $2,080,377 and $383,652 for each of Messrs. Cockrell and Hatley, respectively. These deferred payments were subject to acceleration upon a Change of Control (as defined below), or upon such NEO's termination without Cause (as defined below), for Good Reason (as defined below) or due to death or disability. As a result of the Charlesbank Change of Control, these deferred payments were accelerated, resulting in the full amount of such deferred payments being paid to Messrs. Cockrell and Hatley in 2010. Mr. Hatley is, and Mr. Cockrell was, also eligible, during the respective term of his employment with the General Partner, for discretionary bonus awards and long-term incentives which may be made from time to time in the sole discretion of the Board. The employment agreements also provide that Messrs. Cockrell and Hatley are eligible to participate in any employee benefit plans maintained by the General Partner, during the term of his employment with the General Partner and for up to 18 months thereafter, and are entitled to reimbursement for certain out-of-pocket expenses. Messrs. Cockrell and Hatley have agreed not to disclose any confidential information obtained while employed under their respective employment agreement and has agreed to a one year non-solicitation covenant, which in no event will continue past the fifth anniversary of the effective date of the agreement.

Except in the event of termination for Cause (as defined below), termination by the NEO other than for Good Reason (as defined below), termination after the expiration of the term of the NEO’s employment agreement or termination due to death or disability, the employment agreements provide for payment of any unpaid base salary and vested benefits under any incentive plans, a lump sum payment equal to the NEO’s base salary for the lesser of (i) two years or (ii) the remainder of the employment term, and continued participation in our General Partner’s welfare benefit programs for the same period of time. Based upon his current base salary, the maximum amount of the lump sum severance payment would be $380,000 for Mr. Hatley, in addition to continued participation in the General Partner’s welfare benefit programs and the amounts of unpaid base salary and benefits under any incentive plans. Upon termination of his employment due to death or disability, Mr. Hatley and/or his dependents would be entitled to the benefits continuation described above, his unpaid base salary and accelerated payment of the deferred payment amounts described above.

Mr. Cockrell's employment with our General Partner was ended effective October 31, 2012. Accordingly, Mr. Cockrell received a lump sum payment of $564,000, which was equal to twenty-four months of his base salary, and automatic vesting of 70,000 phantom units he was granted in March 2011 and 2012 pursuant to our General Partner's Long-Term Incentive Plan. These units were repurchased from Mr. Cockrell for $455,700. In addition, Mr. Cockrell received a lump sum payment of $630,300 pursuant to a guarantee letter between Vitol and Mr. Cockrell.

For purposes of the employment agreements of Messrs. Cockrell and Hatley:

"Cause" means (i) conviction of the officer by a court of competent jurisdiction of any felony or a crime involving moral turpitude; (ii) the officer's willful and intentional failure or willful intentional refusal to follow reasonable and lawful instructions of the Board; (iii) the officer's material breach or default in the performance of his obligations under the employment agreement; or (iv) the officer's act of misappropriation, embezzlement, intentional fraud or similar conduct involving the General Partner.

"Good Reason" means (i) a material reduction in the officer's base salary; (ii) a material diminution of the officer's duties, authority or responsibilities as in effect immediately prior to such diminution; or (iii) the relocation of the officer's principal work location to a location more than 100 miles from its current location.

"Change of Control" means any of the following events: (i) any person or group other than SemGroup, L.P. or Vitol, or their respective affiliates, shall become the beneficial owner, by way of merger, consolidation, recapitalization, reorganization or otherwise, of 50% or more of the combined voting power of the equity interests in the Partnership or in the General Partner; (ii) the Partnership's limited partners approve, in one or a series of transactions, a plan of complete liquidation of the Partnership; (iii) the sale or other disposition by either the General Partner or the Partnership of all or substantially all of the assets of the General Partner or the Partnership in one or more transactions to any person other than the General Partner and its affiliates; or (iv) a transaction resulting in a person other than the General Partner or an affiliate of the General Partner being the Partnership's general partner.

Potential Payments Upon Change of Control or Termination.

Employment Agreements. Each of the employment agreements with our compensated NEOs contain provisions that could result in the payment of amounts to such individuals upon a termination or change of control (as defined in such employment agreements). Messrs. Parson and Cockrell's employment was ended effective March 9, 2012 and October 31, 2012, respectively. Payments to them in connection with the end of their employment with our General Partner are discussed above. The term of Mr. Hatley's employment agreement ended on March 10, 2013.

As described above, under Messrs. Hurley, Stallings and Griffin's employment agreements, they are entitled to certain payments if the employment agreement is terminated in certain circumstances as described above. Upon such an event, Messrs. Hurley, Stallings and Griffin would be entitled to a lump sum payment of $425,000, $300,000 and $210,000, respectively, in addition to continued participation in our General Partner's welfare benefit programs and the amounts of unpaid base salary and benefits under any incentive plans. In addition, as described above, under Messrs. Hurley, Stallings and Griffin's employment agreements, if within one year after a Change of Control (as defined above) occurs, he will be entitled to certain payments as described above. Upon such an event, Messrs. Hurley, Stallings and Griffin would be entitled to a lump sum payment of $850,000, $600,000 and $420,000, respectively, in addition to continued participation in our General Partner's welfare benefit programs and the amounts of unpaid base salary and benefits under any incentive plans.

LTIP Awards. The restricted and phantom units granted under the Long-Term Incentive Plan will vest automatically upon a change of control (as defined in the Long-Term Incentive Plan) of us or our General Partner, subject to any contrary provisions in the award agreement.

Charlesbank Change of Control

As described above, the Charlesbank Change of Control resulted in a change of control under the employment agreements of Messrs. Cockrell, Stallings, Parsons, Hatley and Griffin. Messrs. Cockrell, Stallings, Parsons, Hatley and Griffin were not entitled to these benefits as they were not terminated by our General Partner without Cause nor did they terminate their agreements for Good Reason during the one-year period following the Charlesbank Change in Control.

Long-Term Incentive Plan

General.  Our General Partner has adopted the Long-Term Incentive Plan for employees, consultants and directors of our General Partner and its affiliates who perform services for us. The summary of the Long-Term Incentive Plan contained herein does not purport to be complete and is qualified in its entirety by reference to the Long-Term Incentive Plan. The Long-Term Incentive Plan provides for the grant of unit awards, restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights and substitute awards. Subject to adjustment for certain events, an aggregate of 2,600,000 common units may be delivered pursuant to awards under the Long-Term Incentive Plan. Units that are canceled, forfeited or withheld to satisfy our General Partner's tax withholding obligations are available for delivery pursuant to other awards. The Long-Term Incentive Plan is administered by the compensation committee of our General Partner's board of directors. The Long-Term Incentive Plan has been designed to furnish additional compensation to employees, consultants and directors and to align their economic interests with those of common unitholders.  In March 2011, the Long-Term Incentive Plan was amended to update the change of control provisions for the Charlesbank Change of Control and to reflect changes relating to Section 409A of the Internal Revenue Code.  In September 2011 the Long-Term Incentive Plan was amended to increase the number of common units reserved for issuance under the incentive plan by 1,350,000 common units from 1,250,000 common units to 2,600,000 common units.

Unit Awards.  The compensation committee may grant unit awards to eligible individuals under the Long-Term Incentive Plan. A unit award is an award of common units that are fully vested upon grant and not subject to forfeiture.

Restricted Units and Phantom Units.  A restricted unit is a common unit that is subject to forfeiture. Upon vesting, the forfeiture restrictions lapse and the recipient holds a common unit that is not subject to forfeiture. A phantom unit is a notional 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 equal to the fair market value of a common unit. The compensation committee may make grants of restricted units and phantom units under the Long-Term Incentive Plan to eligible individuals containing such terms, consistent with the Long-Term Incentive Plan, as the compensation committee may determine, including the period over which restricted units and phantom units granted will vest. The compensation committee may, in its discretion, base vesting on the grantee's completion of a period of service or upon the achievement of specified financial objectives or other criteria. In addition, the restricted and phantom units will vest automatically upon a change of control (as defined in the Long-Term Incentive Plan) of us or our General Partner, subject to any contrary provisions in the award agreement.  The Charlesbank Change of Control constituted a change of control under the Long-Term Incentive Plan.  See "-Charlesbank Change of Control" above.

If a grantee's employment, consulting relationship or membership on the board of directors terminates for any reason, the grantee's restricted units and phantom units will be automatically forfeited unless, and to the extent, the award agreement or the compensation committee provides otherwise.

Distributions made by us with respect to awards of restricted units may, in the compensation committee's discretion, be subject to the same vesting requirements as the restricted units. The compensation committee, in its discretion, may also grant tandem distribution equivalent rights with respect to phantom units.

We intend for restricted units and phantom units granted under the Long-Term Incentive 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, participants will not pay any consideration for the common units they receive with respect to these types of awards, and neither we nor our General Partner will receive remuneration for the units delivered with respect to these awards.

Options and Unit Appreciation Rights. The Long-Term Incentive Plan also permits the grant of options covering common units and unit appreciation rights. Options represent the right to purchase a number of common units at a specified exercise price. Unit appreciation rights represent the right to receive the appreciation in the value of a number of common units over a specified exercise price, either in cash or in common units as determined by the compensation committee. Options and unit appreciation rights may be granted to such eligible individuals and with such terms as the compensation committee may determine, consistent with the Long-Term Incentive Plan; however, an option or unit appreciation right must have an exercise price equal to the fair market value of a common unit on the date of grant.

Distribution Equivalent Rights. Distribution equivalent rights are rights to receive all or a portion of the distributions otherwise payable on units during a specified time. Distribution equivalent rights may be granted alone or in combination with another award.

By giving participants the benefit of distributions paid to unitholders generally, grants of distribution equivalent rights provide an incentive for participants to operate our business in a manner that allows our partnership to provide increasing partnership distributions. Typically, distribution equivalent rights will be granted in tandem with a phantom unit, so that the amount of the participant's compensation is tied to both the market value of our units and the distributions that unitholders receive while the award is outstanding. We believe this aligns the participant's incentives directly to the measures that drive returns for our unitholders.

Substitute Awards. The compensation committee, in its discretion, may grant substitute or replacement awards to eligible individuals who, in connection with an acquisition made by us, our General Partner or an affiliate, have forfeited an equity-based award in their former employer. A substitute award that is an option may have an exercise price less than the value of a common unit on the date of grant of the award.

Source of Common Units; Cost. Common units to be delivered with respect to awards may be common units acquired by our General Partner on the open market, common units already owned by our General Partner, common units acquired by our General Partner directly from us or any other person or any combination of the foregoing. Our General Partner will be entitled to reimbursement by us for the cost incurred in acquiring common units. With respect to options, our General Partner will be entitled to reimbursement by us for the difference between the cost incurred by our General Partner in acquiring these units and the proceeds received from an optionee at the time of exercise. Thus, we will bear the cost of the options. If we issue new units with respect to these awards, the total number of units outstanding will increase, and our General Partner will remit the proceeds it receives from a participant, if any, upon exercise of an award to us. With respect to any awards settled in cash, our General Partner will be entitled to reimbursement by us for the amount of the cash settlement.

Amendment or Termination of Long-Term Incentive Plan. The Board, in its discretion, may terminate the Long-Term Incentive Plan at any time with respect to the units for which a grant has not theretofore been made. The Long-Term Incentive Plan will automatically terminate on the earlier of the 10th anniversary of the date it was initially approved by our unitholders or when units are no longer available for delivery pursuant to awards under the Long-Term Incentive Plan. The Board will also have the right to alter or amend the Long-Term Incentive Plan or any part of it from time to time and the compensation committee may amend any award; provided, however, that no change in any outstanding award may be made that would materially impair the rights of the participant without the consent of the affected participant.

Summary Compensation Table

The following table summarizes the compensation of our NEOs for the fiscal years ended 2012, 2011 and 2010.

| Name and Position[(1)] | Year | Salary ($)[(2)] | Bonus ($) | Stock Awards ($)[(3)] | Option Awards ($) | Non-Equity Incentive Compensation ($) | All Other Compensation ($)[(4)(5)] | Total ($) |
|---|---|---|---|---|---|---|---|---|
| Mark A. Hurley | 2012 | 117,692 | 100,000 | 2,810,000 | — | — | 5,084 | 3,032,776 |
| Chief Executive Officer | 2011 | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| | 2010 | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| Alex G. Stallings | 2012 | 300,000 | 135,000 | 135,200 | — | — | 56,545 | 626,745 |
| Chief Financial Officer | 2011 | 300,000 | 125,000 | 123,750 | — | — | 45,222 | 593,972 |
| and Secretary | 2010 | 300,000 | 75,000 | — | — | — | 19,900 | 394,900 |
| James R. Griffin | 2012 | 210,000 | 80,000 | 81,120 | — | — | 29,356 | 400,476 |
| Chief Accounting Officer | 2011 | 210,000 | 75,000 | 82,500 | — | — | 22,186 | 389,686 |
| | 2010 | 210,000 | 39,000 | — | — | — | 4,039 | 253,039 |
| Jeffery A. Speer | 2012 | 210,000 | 110,000 | 135,200 | — | — | 45,524 | 500,724 |
| Senior Vice President - | 2011 | 208,000 | 100,000 | 123,750 | — | — | 30,373 | 462,123 |
| Operations | 2010 | 208,000 | 70,000 | — | — | — | 11,285 | 289,285 |
| Larry E. Hatley | 2012 | 190,000 | 100,000 | 135,200 | — | — | 57,193 | 482,393 |
| Vice President - Transportation, | 2011 | 185,000 | 50,000 | 70,125 | — | — | 46,471 | 351,596 |
| Marketing and Operations | 2010 | 151,600 | — | — | — | — | 396,900 | 548,500 |
| James C. Dyer, IV | 2012 | — | — | — | — | — | — | — |
| Former Chief Executive | 2011 | — | — | — | — | — | — | — |
| Officer | 2010 | — | — | — | — | — | — | — |
| J. Michael Cockrell | 2012 | 253,312 | 175,000 | 270,400 | — | — | 1,710,424 | 2,409,136 |
| Former President and | 2011 | 282,000 | 175,000 | 247,500 | — | — | 29,401 | 733,901 |
| Chief Operating Officer | 2010 | 282,000 | — | — | — | — | 2,102,200 | 2,384,200 |
| Jerry A. Parsons | 2012 | 52,326 | 125,000 | — | — | — | 276,314 | 453,640 |
| Former Executive Vice | 2011 | 250,000 | 150,000 | 82,500 | — | — | 39,858 | 522,358 |
| President - Products | 2010 | 250,000 | 50,000 | — | — | — | 10,653 | 310,653 |

(1) Mr. Hurley was appointed as our General Partner’s Chief Executive Officer in September 2012. Mr. Stallings has served as our General Partner’s Chief Financial Officer and Secretary since March 2009. Mr. Griffin has served as our General Partner's Chief Accounting Officer since March 2009. Mr. Speer served as the Vice President of Operations for one of our subsidiaries prior to February 2010 and has served as our General Partner’s Senior Vice President - Operations since February 2010. Mr. Hatley has served as our Vice President - Transportation and Marketing Operations sinceMarch 2010. Mr. Dyer served as our General Partner’s Chief Executive Officer from December 2009 to September 2012 and was compensated by Vitol. Mr. Cockrell served as our General Partner’s President and Chief Operating Officer from December 2009 until October 31, 2012. Mr. Parsons served as our General Partner’s Executive Vice President – Products from October 2010 until March 9, 2012.

(2) Messrs. Speer and Hatley’s annual base salary was increased to $210,000 and $190,000, respectively in 2012. In March 2013, Messrs. Stallings, Speer, Hatley and Griffin's annual base salary was increased to $306,000, $214,000, $192,456 and $214,000, respectively.

(3) Dollar amounts represent the grant date fair value of awards granted in each year with respect to phantom unit grants under the Long-Term Incentive Plan. See Note 13 to our Consolidated Financial Statements for assumptions used in calculating these amounts.

(4) We provide country club memberships, car allowances, reimbursement of certain deductibles and co-payments for medical expenses and discretionary matching and profit sharing contributions to our 401(k) plan to our compensated NEOs.

(5) Other compensation in 2010 includes deferred payments of $2,080,377 and $383,652 for Messrs. Cockrell and Hatley, respectively, which was accelerated as a result of the Charlesbank Change of Control.

(6) Mr. Cockrell's employment with our General Partner was ended effective October 31, 2012. Accordingly, Mr. Cockrell received a lump sum payment of $564,000, which was equal to twenty-four months of his base salary, and automatic vesting of 70,000 phantom units he was granted in March 2011 and 2012 pursuant to our General Partner’s Long-Term Incentive Plan. These units were repurchased from Mr. Cockrell for $455,700. In addition, Mr. Cockrell received a lump sum payment of $630,300 pursuant to a guarantee letter between Vitol and Mr. Cockrell. The total of these payments, $1,650,000, is included in other compensation in 2012.

Pension Benefits

We do not have a pension plan in which our named executive officers are eligible to participate.

Non-Qualified Deferred Compensation

We do not have a non-qualified deferred compensation plan.

Grants of Plan-Based Awards Table for Fiscal 2012

The following tables provide information concerning each grant of an award made to a NEO during 2012, including, but not limited to, awards made under our General Partner's Long-Term Incentive Plan.

| | | Estimated Future Payments Under Non-Equity Incentive Plan Awards | | | Estimated Future Payouts Under Equity Incentive Plan Awards | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Name | Grant Date | Threshold ($) | Target ($) | Maximum ($) | Threshold ($) | Target ($) | Maximum ($) | All Other Unit Awards: Number of Units (#)(1)(2) | All Other Unit Awards: Number of Securities Underlying Options (#) | Exercise or Base Price of Option Awards ($/Sh) | Grant Date Fair Value of Unit and Option Awards ($) |
| Mark A. Hurley | September 20, 2012 | — | — | — | — | — | — | 500,000 | — | — | 2,809,483 |
| Alex G. Stallings | March 7, 2012 | — | — | — | — | — | — | 20,000 | — | — | 135,200 |
| James R. Griffin | March 7, 2012 | — | — | — | — | — | — | 12,000 | — | — | 81,120 |
| Jeffrey A. Speer | March 7, 2012 | — | — | — | — | — | — | 20,000 | — | — | 135,200 |
| Larry E. Hatley | March 7, 2012 | — | — | — | — | — | — | 20,000 | — | — | 135,200 |
| J. Michael Cockrell | March 7, 2012 | — | — | — | — | — | — | 40,000 | — | — | 270,400 |

(1) This amount represents grants of phantom units under our General Partner's Long-Term Incentive Plan. See Note 13 to our Consolidated Financial Statements.
(2) No awards were granted to Messrs. Dyer or Parsons in 2012.

Outstanding Equity Awards at Fiscal Year-End 2012

The following tables provide information concerning all outstanding equity awards made to a named executive officer as of December 31, 2012, including, but not limited to, awards made under our General Partner's Long-Term Incentive Plan.

| | Option Awards | | | | | Stock Awards | | | |
|---|---|---|---|---|---|---|---|---|---|
| Name[6] | Number of Securities Underlying Unexercised Options (#) Exercisable | Number of Securities Underlying Unexercised Options (#) Unexercisable | Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#) | Option Exercise Price ($) | Option Expiration Date | Number of Units That Have Not Vested (#) | Market Value of Units That Have Not Vested ($) | Equity Incentive Plan Awards: Number of Unearned Units or Other Rights That Have Not Vested (#) | Equity Incentive Plan Awards: Market or Payout Value of Unearned Units or Other Rights That Have Not Vested ($) |
| Mark A. Hurley | — | — | — | — | — | — | — | 500,000 [1] | 2,953,033 [2] |
| Alex G. Stallings | — | — | — | — | — | — | — | 15,000 [3] | $98,700 [4] |
| | — | — | — | — | — | — | — | 20,000 [5] | $131,600 [4] |
| James R. Griffin | — | — | — | — | — | — | — | 10,000 [2] | $65,800 [4] |
| | — | — | — | — | — | — | — | 12,000 [5] | $78,960 [4] |
| Jeffery A. Speer | — | — | — | — | — | — | — | 15,000 [2] | $98,700 [4] |
| | — | — | — | — | — | — | — | 20,000 [5] | $131,600 [4] |
| Larry E. Hatley | — | — | — | — | — | — | — | 8,500 [2] | $55,930 [4] |
| | — | — | — | — | — | — | — | 20,000 [5] | $131,600 [4] |

(1) Represents phantom units granted in 2012 under our General Partner's Long-Term Incentive Plan. These phantom units will vest ratably over five years, with 20% vesting on each anniversary of the September 20, 2012 grant date. These phantom units do not contain distribution equivalent rights.

(2) Market value of awards reported in this column is calculated as the product of the closing market price ($6.58) of the Partnership's common units at December 31, 2012, less the present value of the estimated distributions to be paid to holders of an outstanding common unit prior to the vesting of the underlying award, and the number of phantom units outstanding at December 31, 2012.

(3) Represents phantom units granted in 2011 under our General Partner's Long-Term Incentive Plan. These phantom units will vest on January 1, 2014. All of the distribution equivalent rights associated with these phantom units are

currently payable.

(4) Market value of awards reported in this column is calculated as the product of the closing market price ($6.58) of the Partnership's common units at December 31, 2012 and the number of phantom units outstanding at December 31, 2012.

(5) Represents phantom units granted in 2012 under our General Partner's Long-Term Incentive Plan. These phantom units will vest on January 1, 2015. All of the distribution equivalent rights associated with these phantom units are currently payable.

(6) No awards were outstanding as of December 31, 2012 for Messrs. Dyer, Cockrell or Parsons.

Option Exercises and Stock Vested Table for Fiscal 2012

The following table provides information regarding each vesting of phantom units held by our named executive officers in 2012.

| Name | Stock Awards[1] Number of Shares Acquired on Vesting (#) | Value Realized on Vesting ($) | |
|---|---|---|---|
| Jerry A. Parsons | 10,000 | 68,000 | (2) |
| J. Michael Cockrell | 70,000 | 455,700 | (3) |

(1) No awards vested in 2012 for Messrs. Hurley, Stallings, Griffin, Speer, Hatley or Dyer.

(2) This value is based on the average of the high and low trading prices of our common unit on April 4, 2012, the date of issuance of such common units.

(3) This value is based on the adjusted close price of our common units on October 31, 2012, the date of vesting of such common units. These units were repurchased by us for this amount.

Director Compensation for Fiscal 2012

| Name | Fees Earned or Paid in Cash ($) | Stock Awards[4] ($) | Option Awards ($) | Non-Equity Incentive Plan Compensation ($) | Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) | All Other Compensation ($) | Total ($) |
|---|---|---|---|---|---|---|---|
| Duke R. Ligon | 161,000 | 16,400 | — | — | — | — | 177,400 |
| James C. Dyer, IV[1][3] | — | — | — | — | — | — | — |
| Miguel A. ("Mike") Loya[1] | — | — | — | — | — | — | — |
| Steven M. Bradshaw | 151,000 | 16,400 | — | — | — | — | 167,400 |
| John A. Shapiro | 151,000 | 16,400 | — | — | — | — | 167,400 |
| Michael R. Eisenson[2] | — | — | — | — | — | — | — |
| Jon M. Biotti[2] | — | — | — | — | — | — | — |
| Francis Brenner[1][3] | — | — | — | — | — | — | — |

(1) Affiliated with Vitol.
(2) Affiliated with Charlesbank.
(3) Mr. Dyer resigned from the Board effective September 20, 2012, and Mr. Brenner was appointed by Blueknight GP Holding, LLC, the sole member of the General Partner, as his replacement.
(4) These amounts represent the grant date fair value of restricted units awarded under the Long-Term Incentive Plan. The grant date fair value of these awards is computed in accordance with ASC 718 Compensation -Stock Compensation . See Note 13 to our Consolidated Financial Statements for assumptions used in calculating these amounts.

Directors who are not officers or employees of any controlling entity or their affiliates receive compensation for attending meetings of the board of directors and committees thereof. Such directors receive (i) $75,000 per year as an annual retainer fee, (ii) $5,000 per year for serving on each committee of the Board (except that the chairperson of each committee will receive $10,000 per year for serving as chairperson of such committee), (iii) $10,000 per year if Chairman of the Board, (iv) $2,000 per diem for each Board or committee meeting attended, (v) 5,000 restricted common units upon becoming a director, vesting in one-third increments over a three-year period, (vi) 2,500 restricted common units on each anniversary of becoming a director, vesting in one-third increments over a three-year period, (vii) reimbursement for out-of-pocket expenses associated with attending Board or committee meetings and (viii) director and officer liability insurance coverage. In addition, each director is fully indemnified by us for actions associated with being a director to the fullest extent permitted under Delaware law.

Compensation Committee Interlocks and Insider Participation

During the year ended December 31, 2012, the compensation committee of our General Partner was comprised of Messrs. Ligon, Bradshaw and Shapiro (Chairman). No member of the compensation committee was an officer or employee of our General Partner.

Compensation Committee Report

The compensation committee of the general partner of Blueknight Energy Partners, L.P. has reviewed and discussed the Compensation Discussion and Analysis section of this report required by Item 402(b) of Regulation S-K with management of the general partner of Blueknight Energy Partners, L.P. and, based on that review and discussion, has recommended that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K.

The Compensation Committee

John A. Shapiro, Committee Chair
Steven M. Bradshaw
Duke R. Ligon

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters.

Security Ownership of Certain Beneficial Owners and Management

The following table sets forth the beneficial ownership of our units as of March 7, 2013 held by:

- each person or group of persons who beneficially own 5% or more of the then outstanding common units;
- all of the directors of our General Partner;
- each named executive officer of our General Partner; and
- all current directors and named executive officers of our General Partner as a group.

Except as indicated by footnote, the persons named in the table below have sole voting and investment power with respect to all units shown as beneficially owned by them, subject to community property laws where applicable. Percentage of total common and Preferred Units beneficially owned is based on 22,675,135 common units and 30,159,958 Preferred Units outstanding as of March 7, 2013.

| Name of Beneficial Owner[1] | Common Units Beneficially Owned | | Percentage of Common Units Beneficially Owned | Preferred Units Beneficially Owned | | Percentage of Preferred Units Beneficially Owned | Percentage of Total Common and Preferred Units Beneficially Owned |
|---|---|---|---|---|---|---|---|
| Blueknight Energy Holding, Inc.[2] | — | | — | 9,156,484 | | 30.4% | 17.3% |
| CB-Blueknight, LLC[3] | — | | — | 9,156,484 | | 30.4% | 17.3% |
| Mark A. Hurley[6] | — | | — | — | | — | — |
| Alex G. Stallings[4][6] | 68,537 | | * | 20,000 | | * | * |
| James R. Griffin[6] | 30,363 | | * | — | | — | * |
| Jeffery A. Speer[6] | — | | — | — | | — | — |
| Larry E. Hatley[6] | — | | — | — | | — | — |
| Duke R. Ligon[5] | 9,999 | | * | 4,455 | | — | * |
| Steven M. Bradshaw[5] | 8,499 | | * | 3,565 | | — | * |
| John A. Shapiro[5] | 7,499 | | * | 2,975 | | — | * |
| Miguel A. ("Mike") Loya[2][7] | — | | — | — | | — | — |
| Michael R. Eisenson[3][8] | — | | — | — | | — | — |
| Jon M. Biotti[3][8] | — | | — | — | | — | — |
| Francis Brenner[7] | — | | — | — | | — | — |
| MSD Capital, L.P.[9] | 3,576,944 | | 15.8% | 1,935,842 | | 6.4% | 10.4% |
| Swank Capital, L.L.C. | 5,086,733 | (10) | 22.4% | 3,397,373 | (11) | 11.3% | 16.1% |
| Neuberger Berman Group LLC[12] | 3,318,721 | | 14.6% | — | | — | 6.3% |
| DG Capital Management, Inc.[13] | 1,348,112 | | 5.9% | — | | — | 2.6% |
| Solus Alternative Asset Management LP[14] | — | | — | 932,692 | | 3.1% | 1.8% |
| All current executive officers and directors as a group (14 persons) | 124,897 | | 0.6% | 30,995 | | 0.1% | 0.3% |

*Less than 1%.

(1) Unless otherwise indicated, the address for all beneficial owners in this table is Two Warren Place, 6120 South Yale Avenue, Suite 500, Tulsa, Oklahoma 74136.

(2)

Blueknight Energy Holding, Inc. is a subsidiary of Vitol. The address for Vitol is 1100 Louisiana Street, Suite 5500, Houston, Texas 77002. Blueknight Energy Holding, Inc. owns 50% of Blueknight GP Holdings, LLC, which owns the membership interests in our General Partner.

(3) CB-Blueknight, LLC is a subsidiary of Charlesbank. The address for Charlesbank is 200 Clarendon Street, 54th Floor, Boston, Massachusetts. CB-Blueknight, LLC owns 50% of Blueknight GP Holdings, LLC, which owns the membership interests in our General Partner.

(4) All the common units owned by Mr. Stallings are pledged as collateral to a bank.

(5) Does not include unvested restricted units granted under the Long-Term Incentive Plan, none of which will vest within 60 days of the date hereof.

(6) Does not include unvested phantom units granted under the Long-Term Incentive Plan, none of which will vest within 60 days of the date hereof.

(7) Messrs. Loya and Brenner are affiliated with Vitol.

(8) Messrs. Eisenson and Biotti are affiliated with Charlesbank.

(9) Based on a Schedule 13D/A, filed November 2, 2011 by MSD Capital, L.P. with the SEC. The filing is made jointly with MSD Torchlight, L.P. and Michael S. Dell. The filers report that they have shared voting power with respect to the 3,576,944 common units and 1,935,842 preferred units and that their address is 645 Fifth Avenue, 21st Floor, New York, New York 10022.

(10) Based on a Schedule 13F-HR for the quarter ended December 31, 2012 filed on February 14, 2013 with the SEC by Cushing MLP Asset Managment, L.P. These units were previously reported on a Schedule 13D/A, filed December 21, 2011 by Swank Capital, L.L.C. with the SEC. The filing was made jointly with Cushing MLP Asset Management, LP and Jerry V. Swank, and reported that they have shared voting power with respect to the common units.

(11) Based on a Schedule 13D/A, filed December 21, 2011 by Swank Capital, L.L.C. with the SEC. The filing is made jointly with Cushing MLP Asset Management, LP and Jerry V. Swank. The filers report that they have shared voting power with respect to the 3,397,373 preferred units and that their address is 8117 Preston Road, Suite 440, Dallas, TX 75225.

(12) Based on a Schedule 13G, filed February 14, 2013 by Neuberger Berman Group LLC with the SEC. The filing is made jointly with Neuberger Berman LLC. The filers report that they have shared voting power with respect to 2,567,046 common units and shared dispositive power with respect to 3,141,632 common units. Their address as reported in such Schedule 13G/A is 605 Third Avenue, New York, New York 10158.

(13) Based on a Schedule 13G, filed December 26, 2012, by DG Capital Management, LLC with the SEC. This filing is made jointly with Dov Gertzulin. The filers report that they each have shared voting power with respect to 1,348,112 common units. Their address as reported on such Schedule 13G is 460 Park Avenue, 13th Floor, New York, NY 10022.

(14) Based on a Schedule 13D, filed February 14, 2013 by Solus Alternative Asset Management LP with the SEC. The filing is made jointly with Solus GP LLC and Christopher Pucillo. The filers report that they each have shared voting power with respect to the 932,692 preferred units and that their address is 410 Park Avenue, 11th Floor, New York, NY 10022.

Securities Authorized for Issuance under Equity Compensation Plans

Equity Compensation Plan Information[1]

| | (a) Number of securities to be issued upon exercise of outstanding options, warrants and rights | (b) Weighted-average exercise price of outstanding options, warrants and rights | (c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) |
|---|---|---|---|
| Equity compensation plans approved by security holders | 1,016,703 | $ — | 880,576 |
| Equity compensation plans not approved by security holders | — | N/A | N/A |
| Total | 1,016,703 | $ — | 880,576 |

(1) Our General Partner has adopted and maintains the Long-Term Incentive Plan for employees, consultants and directors of our General Partner and its affiliates who perform services for us. All outstanding awards under the Long-Term Incentive Plan on the dates of the Vitol Change of Control and the Charlesbank Change of Control vested due to such changes of control. In March of 2011, our General Partner granted an aggregate of 299,900 phantom units to our executive officers and other employees under the long-term incentive plan, including grants to Messrs. Stallings, Griffin, Speer, Hatley, Cockrell and Parsons in the amount of 15,000, 10,000, 15,000, 8,500, 30,000 and 10,000, respectively. In March 2012, our General Partner granted an aggregate of 353,300 phantom units to our executive officers and other employees under the long-term incentive plan, including grants to Messrs.

Stallings, Griffin, Speer, Hatley and Cockrell in the amounts of 20,000, 12,000, 20,000, 20,000 and 40,000, respectively. Each of Messrs. Bradshaw, Ligon and Shapiro were awarded restricted unit grants of 2,500 units in connection with their anniversaries as a member of the Board in 2010, 2011 and 2012. 2,499 units vested on each anniversary in 2011 and 2012. Mr. Hurley was granted 500,000 phantom units upon his appointment of Chief Executive Officer in September 2012. Excluding phantom unit grants, the responses are as follows: (a) 15,003, (b) $0 and (c) 1,882,276. No value is shown in column (b) of the table because the phantom units and restricted units do not have an exercise price. For more information about the Long-Term Incentive Plan, please see "Item 11-Executive Compensation-Compensation Discussion and Analysis-Long-Term Incentive Plan."

## Item 13. Certain Relationships and Related Transactions, and Director Independence.

### Distributions and Payments to Our General Partner and Its Affiliates

Our General Partner is owned by Vitol and Charlesbank, which each own 9,156,484 of the 30,159,958 outstanding Preferred Units, representing an aggregate 34.6% limited partner interest in us as of March 7, 2013. In addition, our General Partner owns a 2.1% general partner interest in us and the incentive distribution rights. For a description of the distributions and payments our General Partner is entitled to receive, see "Item 5-Market for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities-General Partner Interest and Incentive Distribution Rights."

### Agreements with Vitol and Charlesbank

### Global Transaction Agreement and Related Transactions

On October 25, 2010, we entered into the Global Transaction Agreement with Vitol and Charlesbank. Please see "Item 7. Management's Discussion and Analysis of Financial Condition" for a description of such agreement and the related transactions, including the Convertible Debentures and Preferred Units issued to Vitol and Charlesbank.

Agreements with Vitol

Vitol Omnibus Agreement

On February 15, 2010, we entered into an Omnibus Agreement (the “Vitol Omnibus Agreement”) with Vitol. Pursuant to the Vitol Omnibus Agreement, we agreed to provide certain of our employees, consultants and agents (the “Designated Persons”) to Vitol for use by Vitol’s crude oil marketing division. In return, Vitol agreed to reimburse us in an amount equal to (i) the wages, salaries, bonuses, make whole payments, payroll taxes and the cost of all employee benefits of each Designated Person, in each case as adjusted to properly reflect the time spent by such Designated Person in the performance services for Vitol, (ii) all direct expenses, including, without limitation, any travel and entertainment expenses, incurred by each Designated Person in connection with such Designated Person’s provision of services for Vitol, (iii) a monthly charge of $1,500.00 per Designated Person for each Designated Person that performs services for Vitol during any portion of such month, plus (iv) the sum of subsections (i) through (iii) above multiplied by 0.10. In addition, the Vitol Omnibus Agreement provides that if during any month any Designated Person has spent more than 80% of his time performing services for Vitol, then Vitol will have the right for the succeeding three months to request that such individual be transitioned directly to the employment of Vitol. During the twelve months ended December 31, 2010, 2011, and 2012 we received payments of $1.0 million, $1.6 million and $0.1 million, respectively, pursuant to the Vitol Omnibus Agreement. The Vitol Omnibus Agreement was reviewed and approved by the Board’s conflicts committee in accordance with our procedures for approval of related party transactions and the provisions of the Partnership’s partnership agreement. The Partnership and Vitol terminated the Vitol Omnibus Agreement on March 27, 2012.

Vitol Storage Agreements

In connection with our acquisition of certain of our crude oil storage assets from SemCorp in May 2008, we were assigned from SemCorp a storage agreement with Vitol under which we provided crude oil storage services to Vitol (the “2008 Vitol Storage Agreement”). The initial term of the 2008 Vitol Storage Agreement was from June 1, 2008 through June 30, 2010. This agreement was amended in 2010 to extend the term of the agreement until June 1, 2011 and again in 2011 to extend the term of the agreement to June 1, 2012. Because Vitol was a third party (and not a related or affiliated party) at the time of entering into the 2008 Vitol Storage Agreement, such agreement was not approved by the Board or the Board’s conflicts committee in accordance with our procedures for approval of related party transactions. Vitol became a related party when it acquired our General Partner in November 2009 (the “Vitol Change of Control”). Since the amendments occurred subsequent to the Vitol Change of Control, they were reviewed and approved by the Board’s conflicts committee in accordance with our procedures for approval of related party transactions and the provisions of our partnership agreement. We earned revenues of approximately $12.5 million, $13.2 million and $5.5 million from Vitol with respect to services provided pursuant to the 2008 Vitol Storage Agreement for the twelve months ended December 31, 2010, 2011 and 2012, respectively. We believe that the rates we charged Vitol under the 2008 Vitol Storage Agreement were fair and reasonable to us and our unitholders and were comparable with the rates we charged third parties.

In March of 2010, we entered into a second crude oil storage services agreement with Vitol under which we began providing additional crude oil storage services to Vitol effective May 1, 2010 (the “2010 Vitol Storage Agreement”). The initial term of the 2010 Vitol Storage Agreement is five years commencing on May 1, 2010, subject to automatic renewal periods for successive one year periods until terminated by either party with ninety days prior notice. In March 2013, the 2010 Vitol Storage Agreement was amended to adjust the rates we charge Vitol for services provided under the agreement. The 2010 Vitol Storage Agreement, including the amendment thereto, was reviewed and approved by the Board’s conflicts committee in accordance with our procedures for approval of related party transactions and the provisions of our partnership agreement. We generated revenues under this agreement of approximately $8.1 million, $12.3 million and $11.5 million during the twelve months ended December 31, 2010, 2011 and 2012, respectively. We believe that the rates we charge Vitol under the 2010 Vitol Storage Agreement are fair and reasonable to us and our unitholders and are comparable with the rates we charge third parties.

We entered into two new crude oil storage services agreements with Vitol, the “2012 Vitol 12-month Storage Agreement” and the “2012 Vitol 6-month Storage Agreement,” which became effective June 1, 2012, when the 2008 Vitol Storage Agreement expired according to its terms. We believe that the rates we charge Vitol under both of these agreements are fair and reasonable to us and our unitholders and are comparable with the rates we charge third parties. The Board’s conflicts committee reviewed and approved each of these agreements, including the amendments discussed below, in accordance with our procedures for approval of related party transactions and the provisions of our partnership agreement.

Service revenues under the 2012 Vitol 12-month Storage Agreement are based on the 1.0 million barrels of storage capacity of the crude oil storage tanks that are dedicated to Vitol under the agreement. The initial term of the Vitol 12-month Storage Agreement is from June 1, 2012 through May 31, 2013. We generated revenues under this agreement of approximately $3.2 million for the twelve months ended December 31, 2012. In March 2013, this agreement was amended to extend the term through March 31, 2014 and to adjust the rates we charge Vitol for services provided under the agreement.

Service revenues under the 2012 Vitol 6-month Storage Agreement are based on the 0.5 million barrels of storage capacity of the crude oil storage tanks that are dedicated to Vitol under the agreement. The initial term of the 2012 Vitol 6-month Storage Agreement was from June 1, 2012 through November 30, 2012. We generated revenues under this agreement of approximately $1.6 million for the twelve months ended December 31, 2012. Upon expiration of the initial term of this agreement, it became subject to a rolling 90 day cancellation notice. In March 2013, this agreement was amended to extend the term through October 31, 2013 and to adjust the rates we charge Vitol for services provided under the agreement.

During the third quarter of 2012, we entered into another 6-month storage agreement (the "Vitol September 2012 Storage Agreement") with Vitol effective September 1, 2012. We believe that the rates we charge Vitol under this agreement are fair and reasonable to us and our unitholders and are comparable with the rates we charges third parties. The Board's conflicts committee reviewed and approved this agreement, including the amendment discussed below, in accordance with our procedures for approval of related party transactions and the provisions of our partnership agreement. Service revenues under the Vitol September 2012 Storage Agreement are based on the 0.5 million barrels of storage capacity of the crude oil storage tanks that are dedicated to Vitol under the agreement. The initial term of the Vitol September 2012 Storage Agreement was from September 1, 2012 to February 28, 2013. In March 2013, the Vitol September 2012 Storage Agreement was amended to extend the term through October 31, 2013 and to adjust the rates we charge Vitol for services provided under the agreement. We generated revenues under this agreement of approximately $0.9 million for the twelve months ended December 31, 2012.

Vitol Master Lease Agreement

In July 2010, we entered into a Master Agreement (the "Master Agreement") relating to the lease of certain vehicles by the Partnership from Vitol. Pursuant to the Master Agreement, we leased certain vehicles, including light duty trucks, tractors, tank trailers and bobtail tank trucks, from Vitol for periods ranging from 36 months to 84 months depending on the type of vehicle. We had the opportunity to purchase each vehicle at the end of the lease at the estimated residual value of such vehicle. Leases under the Master Agreement were accounted for as operating leases. During the twelve months ended December 31, 2010 and 2011, we recorded expenses under this agreement of approximately $0.1 million and $0.4 million, respectively. The Master Agreement was approved by the Board's conflicts committee in accordance with our procedures for approval of related party transactions and the provisions of our partnership agreement. In September 2011, we entered into a new master lease agreement with an unrelated third party and terminated the Master Agreement with Vitol.

Vitol Throughput Capacity Agreement

In August 2010, we entered into a Throughput Capacity Agreement (the "ENPS Throughput Agreement") with Vitol. Pursuant to the ENPS Throughput Agreement, Vitol purchased 100% of the throughput capacity on our Eagle North Pipeline System ("ENPS"). We put ENPS in service in December 2010. Vitol paid us a prepaid fee equal to $5.5 million and will pay additional usage fees for every barrel delivered by or on behalf of Vitol on the system. In addition, if the payments made by Vitol in any contract year under the ENPS Throughput Agreement are in the aggregate less than $2.4 million, then Vitol will pay us a deficiency payment equal to $2.4 million minus the aggregate amount of all payments made by Vitol during such contract year. In March 2012, we received a deficiency payment of $0.3 million from Vitol in relation to the 2011 contract year. The ENPS Throughput Agreement has a term that extends for four years after ENPS is completed and may be extended by mutual agreement of the parties for additional one-year terms. If the capacity on ENPS is unavailable for use by Vitol for more than 60 days, whether consecutive or nonconsecutive, during the term of the ENPS Throughput Agreement, then Vitol shall have the right to terminate the ENPS Throughput Agreement within six months after such lack of capacity. We previously contracted to provide throughput services on ENPS to a third party and Vitol's rights to the capacity of ENPS are subordinate to the rights of such third party. In addition, for so long as a default by Vitol relating to payments under the ENPS Throughput Agreement has not occurred and is continuing, we will remit to Vitol any and all tariffs and deficiency payments received by us from such third party pursuant to its agreement with us. The ENPS Throughput Agreement was approved by the Board's conflicts committee in accordance with our procedures for approval of related party transactions and the provisions of our partnership agreement.

During the twelve months ended December 31, 2010, 2011, and 2012, the Partnership incurred interest expense under this agreement of approximately $0.2 million, $0.7 million and $0.5 million, respectively. The agreement has an effective annual interest rate of 14.1% and matures on December 31, 2014.

Vitol Operating and Maintenance Agreement

In August 2011, we entered into an operating and maintenance agreement (the "Vitol O&M Agreement") with Vitol relating to the operation and maintenance of Vitol's crude oil terminal located in Midland, Texas (the "Midland Terminal"). Pursuant to the Vitol O&M Agreement, we provide certain operating and maintenance services with respect to the Midland Terminal. The term of the Vitol O&M Agreement commenced on September 1, 2012 and shall continue for five years. During the twelve months ended December 31, 2012, we generated revenues of $0.2 million under this agreement. We believe that the rates we charge Vitol under this agreement are fair and reasonable to us and our unitholders and are comparable with the rates we charge third parties. The Board's conflicts committee reviewed and approved this agreement in accordance with our procedures for approval of related party transactions and the provisions of our partnership agreement.

Vitol Shared Services Agreement

In August 2012, we entered into a shared services agreement (the "Vitol Shared Services Agreement") with Vitol pursuant to which we provide Vitol certain strategic assessment, economic evaluation and project design services. The term of the Vitol Shared Services Agreement commenced on August 1, 2012 and shall continue for one year. The Vitol Shared Services Agreement renews annually unless terminated by either party as provided in the agreement. During the twelve months ended December 31, 2012, we generated revenues of $0.3 million under this agreement. We believe that the rates we charge Vitol under this agreement are fair and reasonable to us and our unitholders. The Board's conflicts committee reviewed and approved this agreement in accordance with our procedures for approval of related party transactions and the provisions of our partnership agreement.

Vitol's Commitment under Our Credit Agreement

Vitol is a lender under our current credit agreement and has committed to loan us $15.0 million pursuant to such agreement.  Vitol received its pro rata portion of the interest payments in connection with being a lender under the credit agreement and received approximately $0.4 million, $0.7 million and $0.7 million in 2010, 2011 and 2012, respectively, in connection therewith.

Indemnification of Directors and Officers

Under our partnership agreement, in most circumstances, we will indemnify the following persons, to the fullest extent permitted by law, from and against all losses, claims, damages or similar events:

- our General Partner;
- any departing general partner;
- any person who is or was an affiliate of a general partner or any departing general partner;
- any person who is or was a director, officer, member, partner, fiduciary or trustee of any entity set forth in the preceding three bullet points;
- any person who is or was serving as director, officer, member, partner, fiduciary or trustee of another person at the request of our General Partner or any departing general partner; and
- any person designated by our General Partner.

Any indemnification under these provisions will only be out of our assets. Unless it otherwise agrees, our General Partner will not be liable for, or have any obligation to contribute or lend funds or assets to us to enable us to effectuate, indemnification.  We may purchase insurance against liabilities asserted against and expenses incurred by persons for our activities, regardless of whether we would have the power to indemnify the person against liabilities under our partnership agreement.

We and our General Partner have also entered into separate indemnification agreements with each of the directors and officers of our General Partner. The terms of the indemnification agreements are consistent with the terms of the indemnification provided by our partnership agreement and our General Partner's limited liability company agreement. The indemnification agreements also provide that we and our General Partner must advance payment of certain expenses to such indemnified directors and officers, including fees of counsel, subject to receipt of an undertaking from the indemnitee to return such advance if it is it is ultimately determined that the indemnitee is not entitled to indemnification.

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 our General Partner or to our management, as appropriate. If the Board is involved in the approval process, it determines whether to refer the matter to the conflicts committee of the Board, 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.

Director Independence

Please see "Item 10-Directors, Executive Officers and Corporate Governance" of this report for a discussion of director independence matters.

Item 14. Principal Accountant Fees and Services.

We have engaged PricewaterhouseCoopers LLP as our principal accountant. The following table summarizes fees we have paid PricewaterhouseCoopers LLP for independent auditing, tax and related services for each of the last two fiscal years:

| | Year ended December 31, | |
|---|---|---|
| | 2011 | 2012 |
| Audit fees(1) | $800,300 | $610,550 |
| Audit-related fees(2) | — | — |
| Tax fees(3) | 202,649 | 222,189 |
| All other fees(4) | 250 | 250 |

(1) Audit fees represent amounts billed for each of the years presented for professional services rendered in connection with (a) the audit of our annual financial statements and internal controls over financial reporting, (b) the review of our quarterly financial statements and (c) those services normally provided in connection with statutory and regulatory filings or engagements, including comfort letters, consents and other services related to SEC matters.

(2) Audit-related fees represent amounts we were billed in each of the years presented for assurance and related services that are reasonably related to the performance of the annual audit or quarterly reviews.

(3) Tax fees represent amounts we were billed in each of the years presented for professional services rendered in connection with tax compliance, tax advice and tax planning. This category primarily includes services relating to the preparation of unitholder annual K-1 statements.

(4) All other fees represent amounts we were billed in each of the years presented for services not classifiable under the other categories listed in the table above.

All audit and non-audit services provided by PricewaterhouseCoopers LLP are subject to pre-approval by our audit committee to ensure that the provisions of such services do not impair the auditor's independence. Under our pre-approval policy, the audit committee is informed of each engagement of the independent auditor to provide services under the policy. The audit committee of our General Partner has approved the use of PricewaterhouseCoopers LLP as our independent principal accountant.

PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a) Financial Statements and Schedules

(1) See the Index to Financial Statements on page F-1.

(2) All schedules have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto

(3) Exhibits

INDEX TO EXHIBITS

| Exhibit Number | Description |
|---|---|
| 3.1 | Amended and Restated Certificate of Blueknight Energy Partners, L.P. (the “Partnership”), dated November 19, 2009 but effective as of December 1, 2009 (filed as Exhibit 3.1 to the Partnership’s Current Report on Form 8-K, filed November 24, 2009, and incorporated herein by reference). |
| 3.2 | Fourth Amended and Restated Agreement of Limited Partnership of the Partnership, dated September 14, 2011 (filed as Exhibit 3.1 to the Partnership’s Current Report on Form 8-K, filed September 14, 2011, and incorporated herein by reference). |
| 3.3 | Amended and Restated Certificate of Formation of the General Partner, dated November 19, 2009 but effective as of December 1, 2009 (filed as Exhibit 3.2 to the Partnership’s Current Report on Form 8-K, filed November 24, 2009, and incorporated herein by reference). |
| 3.4 | Second Amended and Restated Limited Liability Company Agreement of the General Partner, dated December 1, 2009 (filed as Exhibit 3.2 to the Partnership’s Current Report on Form 8-K, filed December 7, 2009, and incorporated herein by reference). |
| 4.1 | Specimen Unit Certificate (included in Exhibit 3.2). |
| 4.2 | Registration Rights Agreement, dated as of October 25, 2010, by and among Blueknight Energy Partners, L.P., Blueknight Energy Holding, Inc. and CB-Blueknight, LLC (filed as Exhibit 4.1 to the Partnership’s Current Report on Form 8-K, filed October 25, 2010, and incorporated herein by reference). |
| 4.3 | Specimen Right Certificate (filed as Exhibit 4.2 to the Partnership’s Current Report on Form 8-K, filed September 27, 2011, and incorporated herein by reference). |
| 4.4 | Rights Agent Agreement, dated as of September 27, 2011, between Blueknight Energy Partners, L.P. and American Stock Transfer & Trust Company, LLC, as rights agent (filed as Exhibit 4.1 to the Partnership’s Current Report on Form 8-K, filed September 27, 2011, and incorporated herein by reference). |
| 4.5 | Specimen Series A Preferred Unit Certificate (filed as Exhibit 4.3 to the Partnership’s Current Report on Form 8-K, filed September 27, 2011, and incorporated herein by reference). |
| 10.1 | Consulting Services Agreement, dated August 17, 2011 to be effective as of July 1, 2011, by and between BKEP Pipeline, L.L.C. and Vitol Midstream LLC (filed as Exhibit 10.1 to the Partnership’s Current Report on Form 8-K, filed August 18, 2011, and incorporated herein by reference). |
| 10.2 | Operating and Maintenance Agreement, dated August 17, 2011 to be effective as of July 1, 2011, by and between BKEP Pipeline, L.L.C. and Vitol Midstream LLC (filed as Exhibit 10.2 to the Partnership’s Current Report on Form 8-K, filed August 18, 2011, and incorporated herein by reference). |
| 10.3 | Order Preliminarily Approving Settlement, U.S. District Court for the Northern District of Oklahoma, dated June 9, 2011 (filed as Exhibit 10.2 to the Partnership’s Current Report on Form 8-K, filed on June 13, 2011, |

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|---|---|
| | and incorporated herein by reference). |
| 10.4 | Stipulation of Settlement, dated May 3, 2011 (filed as Exhibit 10.1 to the Partnership's Current Report on Form 8-K, filed on May 6, 2011 and incorporated herein by reference). |
| 10.5 | Credit Agreement, dated as of October 25, 2010, by and among the Partnership, JPMorgan Chase Bank, N.A., as Administrative Agent, and the other agents and lenders party thereto (filed as Exhibit 10.2 to the Partnership's Current Report on Form 8-K, filed October 25, 2010, and incorporated herein by reference). |
| 10.6 | First Amendment to Credit Agreement, dated as of April 1, 2011, by and among Blueknight Energy Partners, L.P., JPMorgan Chase Bank, N.A., as administrative agent, and the lenders party thereto (filed as Exhibit 1-.1 to the Partnership's Current Report on Form 8-K, filed April 5, 2011 and incorporated herein by reference). |

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| 10.7 | Joinder Agreement, dated as of April 5, 2011, by and among Blueknight Energy Partners, L.P., Boerenleenbank B.A. “Rabobank Nederland”, New York Branch (filed as Exhibit 10.2 to the Partnership’s Current Report on Form 8-K, filed April 5, 2011 and incorporated herein by reference). |
| 10.8 | Convertible Subordinated Debenture of the Partnership in favor of Blueknight Energy Holding, Inc., dated as of October 25, 2010 (filed as Exhibit 10.3 to the Partnership’s Current Report on Form 8-K, filed October 25, 2010, and incorporated herein by reference). |
| 10.9 | Convertible Subordinated Debenture of the Partnership in favor of CB-Blueknight, LLC, dated as of October 25, 2010 (filed as Exhibit 10.4 to the Partnership’s Current Report on Form 8-K, filed October 25, 2010, and incorporated herein by reference). |
| 10.10 | Global Transaction Agreement, dated as of October 25, 2010, by and among Blueknight Energy Partners G.P., L.L.C., the Partnership and the purchasers set forth in Schedule I thereto (filed as Exhibit 10.1 to the Partnership’s Current Report on Form 8-K, filed October 25, 2010, and incorporated herein by reference). |
| 10.11 | First Amendment to Global Transaction Agreement, dated May 12, 2011, by and among Blueknight Energy Partners, L.P., Blueknight Energy Partners G.P., L.L.C., Blueknight Energy Holding, Inc. and CB-Blueknight, LLC (filed as Exhibit 10.1 to the Partnership’s Current Report on Form 8-K, filed May 13, 2011 and incorporated herein by reference). |
| 10.12# | Crude Oil Storage Services Agreement, effective as of May 1, 2010, by and between BKEP Crude, LLC and Vitol Inc. (filed as Exhibit 10.54 to the Partnership’s Annual Report on Form 10-K, filed on March 30, 2010, and incorporated herein by reference). |
| 10.13*# | First Amendment to Crude Oil Storage Services Agreement, dated to be effective as of March 1, 2013, by and between BKEP Crude, LLC and Vitol Inc. |
| 10.14 | Throughput Capacity Agreement, dated August 31, 2010 to be effective as of March 30, 2010, by and between BKEP Crude, L.L.C. and Vitol Inc. (filed as Exhibit 10.1 to the Partnership’s Quarterly Report on Form 10-Q, filed on November 9, 2010, and incorporated herein by reference). |
| 10.15 | Omnibus Agreement, dated as of February 15, 2010 but effective as of January 1, 2010, by and among BKEP Operating, L.L.C., BKEP Crude, L.L.C., BKEP Management, Inc. and Vitol Inc. (filed as Exhibit 10.1 to the Partnership’s Current Report on Form 8-K, filed on February 16, 2010, and incorporated herein by reference). |
| 10.16 | Master Agreement, dated July 26, 2010, by and between BKEP Operating, L.L.C. and Euromin Inc (filed as Exhibit 10.1 to the Partnership’s Current Report on Form 8-K, filed on July 30, 2010, and incorporated herein by reference). |
| 10.17† | Blueknight Energy Partners G.P., L.L.C. Long-Term Incentive Plan (as amended and restated effective June 9, 2011) (filed as Exhibit 10.1 to the Partnership’s Current Report on Form 8-K, filed September 14, 2011, and incorporated herein by reference). |
| 10.18† | Form of Employment Agreement (filed as Exhibit 10.6 to the Partnership’s Registration Statement on Form S-1 (Reg. No. 333-141196), filed May 25, 2007, and incorporated herein by reference). |
| 10.19† | Form of Employment Agreement (filed as Exhibit 10.14 to the Partnership’s Quarterly Report on Form 10-Q, filed on March 23, 2009, and incorporated herein by reference). |
| 10.20† | Form of Employment Agreement (filed as Exhibit 10.2 to the Partnership’s Current Report on Form 8-K, filed on November 25, 2009, and incorporated herein by reference). |
| 10.21† | Form of Indemnification Agreement (filed as Exhibit 10.7 to the Partnership’s Registration Statement on Form S-1 (Reg. No. 333-141196), filed May 25, 2007, and incorporated herein by reference). |
| 10.22† | Form of Phantom Unit Agreement (filed as Exhibit 10.15 to the Partnership’s Quarterly Report on Form 10-Q, filed on March 23, 2009, and incorporated herein by reference). |
| 10.23† | Form of Phantom Unit Agreement (filed as Exhibit 10.19 to the Partnership’s Annual Report on Form 10-K, filed on March 16, 2011, and incorporated herein by reference). |
| 10.24† | Form of Retention Agreement (filed as Exhibit 10.16 to the Partnership’s Quarterly Report on Form 10-Q, filed on March 23, 2009, and incorporated herein by reference). |
| 10.25† | |

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| | Form of Director Restricted Common Unit Agreement (filed as Exhibit 10.2 to the Partnership's Current Report on Form 8-K, filed on December 23, 2008, and incorporated herein by reference). |
| 10.26† | Form of Director Restricted Subordinated Unit Agreement (filed as Exhibit 10.3 to the Partnership's Current Report on Form 8-K, filed on December 23, 2008, and incorporated herein by reference). |
| 10.27† | SemGroup Energy Partners G.P., L.L.C. 2009 Executive Cash Bonus Plan (filed as Exhibit 10.22 to the Partnership's Annual Report on Form 10-K, filed on July 2, 2009, and incorporated herein by reference). |
| 10.28† | Employment Agreement, dated October 4, 2012, between Mark Hurley and BKEP Management, Inc. (filed as Exhibit 10.1 to the Partnership's Current Report on Form 8-K/A, filed October 4, 2012 and incorporated herein by reference). |
| 10.29† | Employee Phantom Unit Agreement, dated October 4, 2012, between Mark Hurley and Blueknight Energy Partners G.P., L.L.C. (filed as Exhibit 10.2 to the Partnership's Current Report on Form 8-K/A, filed October 4, 2012 and incorporated herein by reference). |

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| 10.30 | Shared Services Agreement, dated as of April 7, 2009 to be effective as of 11:59 PM CDT March 31, 2009, by and among SemGroup Energy Partners, L.P., SemGroup Energy Partners, L.L.C., SemGroup Crude Storage, L.L.C., SemPipe G.P., L.L.C., SemPipe, L.P., SemCrude, L.P. and SemManagement, L.L.C. (filed as Exhibit 10.2 to the Partnership's Current Report on Form 8-K, filed on April 10, 2009, and incorporated herein by reference). |
| 10.31 | Throughput Agreement, dated as of April 7, 2009 to be effective as of 11:59 PM CDT March 31, 2009, by and among SemGroup Energy Partners, L.L.C. and SemCrude, L.P. (filed as Exhibit 10.6 to the Partnership's Current Report on Form 8-K, filed on April 10, 2009, and incorporated herein by reference). |
| 10.32 | Office Lease, dated as of April 7, 2009 to be effective as of 11:59 PM CDT March 31, 2009, by and between SemGroup Energy Partners, L.L.C. and SemCrude, L.P. (filed as Exhibit 10.10 to the Partnership's Current Report on Form 8-K, filed on April 10, 2009, and incorporated herein by reference). |
| 10.33 | Building Lease, dated as of April 7, 2009 to be effective as of 11:59 PM CDT March 31, 2009, by and between SemGroup Energy Partners, L.L.C. and SemCrude, L.P. (filed as Exhibit 10.11 to the Partnership's Current Report on Form 8-K, filed on April 10, 2009, and incorporated herein by reference). |
| 10.34 | Mutual Easement Agreement, dated as of April 7, 2009 to be effective as of 11:59 PM CDT March 31, 2009, among SemCrude, L.P., SemGroup Energy Partners, L.L.C., and SemGroup Crude Storage, L.L.C. (filed as Exhibit 10.12 to the Partnership's Current Report on Form 8-K, filed on April 10, 2009, and incorporated herein by reference). |
| 10.35 | Pipeline Easement Agreement, dated as of April 7, 2009 to be effective as of 11:59 PM CDT March 31, 2009, by and among White Cliffs Pipeline, L.L.C., SemGroup Energy Partners, L.L.C., and SemGroup Crude Storage, L.L.C. (filed as Exhibit 10.13 to the Partnership's Current Report on Form 8-K, filed on April 10, 2009, and incorporated herein by reference). |
| 10.36 | Shared Services Agreement, dated to be effective as of August 1, 2012, by and between the Partnership and Vitol Inc. (filed as Exhibit 10.3 to the Partnership's Quarterly Report on Form 10-Q for the quarter ended June 30, 2012 and filed August 7, 2012, and incorporated herein by reference). |
| 10.37# | Crude Oil Storage Services Agreement, dated to be effective as of June 1, 2012, by and between BKEP Pipeline, LLC and Vitol Inc. (filed as Exhibit 10.1 to the Partnership's Quarterly Report on Form 10-Q for the quarter ended March 31, 2012 and filed May 9, 2012, and incorporated herein by reference). |
| 10.38*# | First Amendment to Crude Oil Storage Services Agreement, dated to be effective as of March 1, 2013, by and between BKEP Pipeline, LLC and Vitol Inc. |
| 10.39# | Crude Oil Storage Services Agreement, dated to be effective as of June 1, 2012, by and between BKEP Pipeline, LLC and Vitol Inc. (filed as Exhibit 10.2 to the Partnership's Quarterly Report on Form 10-Q for the quarter ended March 31, 2012 and filed May 9, 2012, and incorporated herein by reference). |
| 10.40*# | First Amendment to Crude Oil Storage Services Agreement, dated to be effective as of March 1, 2013, by and between BKEP Pipeline, LLC and Vitol Inc. |
| 10.41# | Crude Oil Storage Services Agreement, dated to be effective as of September 1, 2012, by and between BKEP Pipeline, LLC and Vitol Inc. (filed as Exhibit 10.4 to the Partnership's Quarterly Report on Form 10-Q for the quarter ended June 30, 2012 and filed August 7, 2012, and incorporated herein by reference). |
| 10.42*# | First Amendment to Crude Oil Storage Services Agreement, dated to be effective as of March 1, 2013, by and between BKEP Pipeline, LLC and Vitol Inc. |
| 10.43 | Second Amendment to Credit Agreement, dated as of November 2, 2012, among the Partnership, the lenders party thereto, and JPMorgan Chase Bank, N.A., as administrative agent (filed as Exhibit 10.5 to the Partnership's Quarterly Report on Form 10-Q for the quarter ended September 30, 2012 and filed November 6, 2012, and incorporated herein by reference). |
| 10.44 | Third Amendment to Credit Agreement, dated as of March 4, 2013, among the Partnership, the lenders party thereto, and JPMorgan Chase Bank, N.A., as administrative agent (filed as Exhibit 10.1 to the Partnership's Current Report on Form 8-K, filed March 5, 2013 and incorporated herein by reference). |
| 21.1* | List of Subsidiaries of Blueknight Energy Partners, L.P. |

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|---|---|
| 23.1* | Consent of PricewaterhouseCoopers, L.L.P. |
| 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 and Chief Financial Officer pursuant to 18 U.S.C., Section 1350, as adopted pursuant to Section 906 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** | The following financial information from Blueknight Energy Partners, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2012, formatted in XBRL (eXtensible Business Reporting Language): (i) Document and Entity Information; (ii) Consolidated Balance Sheets as of December 31, 2011 and 2012; (iii) Consolidated Statements of Operations for the years ended December 31, 2010, 2011 and 2012; (iv)Consolidated Statement of Changes in Partners' Capital for the years ended December 31, 2010, 2011 and 2012; (v) Consolidated Statements of Cash Flows for the years ended December 31, 2010, 2011 and 2012; and (vi) Notes to Consolidated Financial Statements. |

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* Filed herewith.

** Furnished herewith

# Certain portions of this exhibit have been granted confidential treatment by the Securities and Exchange Commission. The omitted portions have been separately filed with the Securities and Exchange Commission.

† As required by Item 15(a)(3) of Form 10-K, this exhibit is identified as a compensatory plan or arrangement.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

BLUEKNIGHT ENERGY PARTNERS, L.P.

By: Blueknight Energy Partners G.P., L.L.C.
Its General Partner

March 14, 2013

By: /s/ Alex G Stallings
Alex G. Stallings
Chief Financial Officer and Secretary

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 March 14, 2013.

| Signature | Title |
|---|---|
| /s/ Mark A. Hurley<br>Mark A. Hurley | Chief Executive Officer and Director<br>(Principal Executive Officer) |
| /s/ Alex G. Stallings<br>Alex G. Stallings | Chief Financial Officer and Secretary<br>(Principal Financial Officer) |
| /s/ James R. Griffin<br>James R. Griffin | Chief Accounting Officer<br>(Principal Accounting Officer) |
| /s/ Duke R. Ligon<br>Duke R. Ligon | Director |
| /s/ Steven M. Bradshaw<br>Steven M. Bradshaw | Director |
| /s/ John A. Shapiro<br>John A. Shapiro | Director |
| /s/ M.A. Loya<br>M.A. Loya | Director |
| /s/ Michael R. Eisenson<br>Michael R. Eisenson | Director |
| /s/ Jon M. Biotti<br>Jon M. Biotti | Director |

| | |
|---|---|
| /s/ Francis Brenner<br>Francis Brenner | Director |

INDEX TO FINANCIAL STATEMENTS

BLUEKNIGHT ENERGY PARTNERS, L.P. AUDITED FINANCIAL STATEMENTS:

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Blueknight Energy Partners GP, L.L.C. and Unitholders of Blueknight Energy Partners, L.P.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, changes in partners' capital and cash flows present fairly, in all material respects, the financial position of Blueknight Energy Partners, L.P. and its subsidiaries (the "Partnership") at December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A in the Partnership's Form 10-K for the year ended December 31, 2012. Our responsibility is to express opinions on these financial statements and on the Partnership's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting 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 audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 (iii) 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.

/s/ PricewaterhouseCoopersLLP
Tulsa, Oklahoma
March 14, 2013

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BLUEKNIGHT ENERGY PARTNERS, L.P.
CONSOLIDATED BALANCE SHEET
(in thousands, except per unit data)

| | As of December 31, | |
|---|---|---|
| | 2011 | 2012 |
| ASSETS | | |
| Current assets: | | |
| Cash and cash equivalents | $1,239 | $3,177 |
| Accounts receivable, net of allowance for doubtful accounts of $476 and $469 at December 31, 2011 and 2012, respectively | 14,191 | 9,948 |
| Receivables from related parties, net of allowance for doubtful accounts of $0 for both dates | 4,397 | 3,522 |
| Prepaid insurance | 1,725 | 1,237 |
| Assets held for sale | 603 | 281 |
| Other current assets | 1,838 | 1,822 |
| Total current assets | 23,993 | 19,987 |
| Property, plant and equipment, net of accumulated depreciation of $135,302 and $153,216 at December 31, 2011 and 2012, respectively | 266,355 | 267,741 |
| Goodwill | 7,216 | 7,216 |
| Debt issuance costs, net | 5,000 | 3,225 |
| Intangibles and other assets, net | 2,191 | 1,656 |
| Total assets | $304,755 | $299,825 |
| LIABILITIES AND PARTNERS' CAPITAL | | |
| Current liabilities: | | |
| Accounts payable | $10,138 | $10,052 |
| Accrued loss contingency | 1,090 | — |
| Accrued interest payable | 231 | 164 |
| Accrued interest payable to related parties | 362 | 304 |
| Accrued property taxes payable | 1,813 | 1,938 |
| Unearned revenue | 790 | 4,068 |
| Unearned revenue with related parties | 1,149 | 316 |
| Accrued payroll | 5,226 | 6,409 |
| Other current liabilities | 3,740 | 4,032 |
| Current portion of long-term payable to related parties | 1,636 | 1,881 |
| Total current liabilities | 26,175 | 29,164 |
| Long-term payable to related parties | 2,681 | 800 |
| Other long-term liabilities | 100 | 206 |
| Long-term debt (including $15.0 million with related parties for both dates) | 218,000 | 211,000 |
| Commitments and contingencies (Notes 8 and 16) | | |
| Partners' capital: | | |
| Series A Preferred Units (30,159,958 units issued and outstanding for both dates) | 202,746 | 204,599 |
| Common unitholders (22,657,638 and 22,675,135 units issued and outstanding at December 31, 2011 and 2012, respectively) | 465,483 | 464,433 |
| General partner interest (2.1% with 1,127,755 general partner units outstanding for both dates) | (610,430) | (610,377) |
| Total Partners' capital | 57,799 | 58,655 |

| | | |
|---|---|---|
| Total liabilities and Partners' capital | $304,755 | $299,825 |

The accompanying notes are an integral part of these financial statements.

BLUEKNIGHT ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per unit data)

| | Year ended December 31, 2010 | 2011 | 2012 |
|---|---|---|---|
| Service revenue: | | | |
| Third party revenue | $129,083 | $132,618 | $134,242 |
| Related party revenue | 23,541 | 44,089 | 48,153 |
| Total revenue | 152,624 | 176,707 | 182,395 |
| Expenses: | | | |
| Operating | 97,713 | 117,851 | 126,262 |
| General and administrative | 20,454 | 17,311 | 19,795 |
| Total expenses | 118,167 | 135,162 | 146,057 |
| Gain on sale of assets | 58 | 3,008 | 7,250 |
| Loss contingency, net of insurance recovery (see Note 3) | 7,200 | — | — |
| Operating income | 27,315 | 44,553 | 43,588 |
| Other (income) expenses: | | | |
| Interest expense (net of capitalized interest of $3,802, $21, and $150, respectively) | 48,638 | 32,898 | 11,705 |
| Change in fair value of embedded derivative within convertible debt | 6,650 | (20,224) | — |
| Change in fair value of rights offering liability | (4,384) | (1,883) | — |
| Income (loss) before income taxes | (23,589) | 33,762 | 31,883 |
| Provision for income taxes | 207 | 287 | 318 |
| Net income (loss) | $(23,796) | $33,475 | $31,565 |
| Allocation of net income (loss) for calculation of earnings per unit: | | | |
| General partner interest in net income (loss) | $(470) | $912 | $774 |
| Preferred interest in net income | $— | $16,446 | $21,564 |
| Accretion of discount on increasing rate Preferred Units | $— | $2,243 | $— |
| Beneficial conversion feature attributable to Preferred Units | $8,114 | $43,259 | $1,853 |
| Beneficial conversion feature attributable to repurchased Preferred Units | $— | $(6,892) | $— |
| Gain on extinguishment attributable to redemption of convertible debt, recorded as a capital transaction | $— | $(2,375) | $— |
| Income (loss) available to limited partners | $(31,440) | $(20,118) | $7,374 |
| | | | |
| Basic and diluted net income (loss) per common unit | $(0.91) | $(0.61) | $0.32 |
| Basic and diluted net loss per subordinated unit | $(0.91) | $(0.52) | $— |
| | | | |
| Weighted average common units outstanding - basic and diluted | 21,744 | 22,059 | 22,668 |
| Weighted average subordinated units outstanding - basic and diluted | 12,571 | 8,817 | — |

The accompanying notes are an integral part of these financial statements.

BLUEKNIGHT ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' CAPITAL
(in thousands)

| | Common Unitholders | Subordinated Unitholders | Series A Preferred Unitholders | General Partner Interest | Total Partners' Capital |
|---|---|---|---|---|---|
| Balance, December 31, 2009 | $471,701 | $(290,257) | $— | $(323,623) | $(142,179) |
| Net loss | (14,693) | (8,484) | — | (619) | (23,796) |
| Equity-based incentive compensation | 69 | 40 | — | 3 | 112 |
| Proceeds from issuance of 21,538,462 Preferred Units, net of offering costs | — | — | 137,758 | — | 137,758 |
| Contingent financial instrument related to additional private placement | 1,507 | 872 | — | — | 2,379 |
| Proceeds from issuance of 437,030 general partner units | — | — | — | 2,809 | 2,809 |
| Rights offering contingency | (9,392) | (5,434) | — | — | (14,826) |
| Beneficial conversion feature of Preferred Units | 34,523 | 19,973 | (54,496) | — | — |
| Amortization of beneficial conversion feature of Preferred Units | (5,140) | (2,974) | 8,114 | — | — |
| Balance, December 31, 2010 | $478,575 | $(286,264) | $91,376 | $(321,430) | $(37,743) |
| Net income | 15,721 | 5,674 | 11,375 | 705 | 33,475 |
| Equity-based incentive compensation | 409 | 124 | — | 11 | 544 |
| Amortization of beneficial conversion feature of Preferred Units | (31,895) | (11,364) | 43,259 | — | — |
| Accretion of discount on Preferred Units | (2,243) | — | 2,243 | — | — |
| Distributions | — | — | (11,375) | (240) | (11,615) |
| Debt conversion option classified as equity | 7,326 | — | — | — | 7,326 |
| Contribution and cancellation of subordinated units | — | 291,830 | — | (291,830) | — |
| Settlement of Class Action Litigation | 5,200 | — | — | — | 5,200 |
| Clawback of LTIP awards | (804) | — | — | (21) | (825) |
| Repurchase of Preferred Units | (1,270) | — | (19,696) | — | (20,966) |
| Proceeds from rights offering | — | — | 77,005 | — | 77,005 |
| Settlement of rights offering liability | — | — | 8,559 | — | 8,559 |
| Gain on extinguishment attributable to redemption of convertible debt | — | — | — | 2,375 | 2,375 |
| Fair value of debt conversion option on reacquisition date | (5,536) | — | — | — | (5,536) |
| Balance, December 31, 2011 | $465,483 | $— | $202,746 | $(610,430) | $57,799 |
| Net income | 9,662 | — | 21,244 | 659 | 31,565 |
| Equity-based incentive compensation | 1,856 | — | — | 41 | 1,897 |
| Settlement of equity awards | (443) | — | — | (10) | (453) |
| Amortization of beneficial conversion feature of Preferred Units | (1,853) | — | 1,853 | — | — |
| Profits interest contribution | — | — | — | 36 | 36 |
| Distributions | (10,272) | — | (21,244) | (673) | (32,189) |
| Balance, December 31, 2012 | $464,433 | $— | $204,599 | $(610,377) | $58,655 |

The accompanying notes are an integral part of these financial statements.

BLUEKNIGHT ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

| | Year ended December 31, | | |
|---|---|---|---|
| | 2010 | 2011 | 2012 |
| Cash flows from operating activities: | | | |
| Net income (loss) | $(23,796 ) | $33,475 | $31,565 |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities: | | | |
| Provision for uncollectible receivables from third parties | — | (47 ) | (6 ) |
| Depreciation and amortization | 21,447 | 22,775 | 23,129 |
| Amortization and write-off of debt issuance costs | 4,329 | 1,955 | 1,775 |
| Impairment of intangible assets | — | — | 96 |
| Amortization of subordinated debenture discount | 3,242 | 15,142 | — |
| Change in fair value of embedded derivative within convertible debt | 6,650 | (20,224 ) | — |
| Change in fair value of rights offering liability | (4,384 ) | (1,883 ) | — |
| Loss Contingency (see Note 3) | 7,200 | — | — |
| Gain on debt refinancing | (1,434 ) | — | — |
| Asset impairment charge | 779 | 867 | 1,846 |
| Gain on sale of assets | (58 ) | (3,008 ) | (7,250 ) |
| Equity-based incentive compensation | 112 | 544 | 1,897 |
| Clawback of LTIP Awards | — | (825 ) | — |
| Settlement of equity-based compensation agreement | — | — | (453 ) |
| Changes in assets and liabilities | | | |
| Decrease (increase) in accounts receivable | 1,725 | (5,320 ) | 4,249 |
| Decrease (increase) in receivables from related parties | (659 ) | (2,485 ) | 875 |
| Decrease in prepaid insurance | 1,150 | 1,404 | 2,430 |
| Decrease (increase) in other current assets | 145 | (216 ) | 16 |
| Decrease (increase) in other assets | (1,335 ) | 1,163 | (6 ) |
| Increase (decrease) in accounts payable | 609 | (1,623 ) | (1,281 ) |
| Increase (decrease) in accrued interest payable | 3,378 | (126 ) | (67 ) |
| Increase (decrease) in accrued interest payable to related parties | 1,214 | (852 ) | (58 ) |
| Increase (decrease) in accrued property taxes | (921 ) | (441 ) | 125 |
| Increase (decrease) in unearned revenue | (1,699 ) | (2,716 ) | 3,278 |
| Increase (decrease) in unearned revenue from related parties | 969 | (1,005 ) | (833 ) |
| Increase in accrued payroll | 705 | 1,096 | 1,183 |
| Increase (decrease) in other accrued liabilities | 523 | (488 ) | (790 ) |
| Net cash provided by operating activities | 19,891 | 37,162 | 61,720 |
| Cash flows from investing activities: | | | |
| Acquisitions | (5,715 ) | (133 ) | — |
| Capital expenditures | (18,101 ) | (17,998 ) | (27,717 ) |
| Proceeds from sale of assets | 1,633 | 7,491 | 10,206 |
| Net cash used in investing activities | (22,183 ) | (10,640 ) | (17,511 ) |
| Cash flows from financing activities: | | | |
| Payment on insurance premium financing agreement | (349 ) | (1,194 ) | (1,482 ) |
| Debt issuance costs | (7,510 ) | (280 ) | — |
| Payments on capital lease obligations | (248 ) | — | — |
| Borrowings from related party | 5,500 | — | — |
| Payments on long-term payable to related party | — | (1,183 ) | (1,636 ) |

| | | | |
|---|---|---|---|
| Borrowings under credit facility | 296,562 | 7,000 | 37,000 |
| Payments under credit facility | (484,700 ) | (28,862 ) | (44,000 ) |
| Proceeds from issuance of convertible subordinated debentures, net of issuance costs | 49,383 | — | — |
| Redemption of convertible subordinated debentures | — | (50,028 ) | — |
| Proceeds from equity issuances, net of offering costs | 142,946 | 77,005 | — |
| Repurchase of Preferred Units | — | (20,966 ) | — |
| Capital contribution related to profits interest (see Note 14) | — | — | 36 |
| Distributions | — | (11,615 ) | (32,189 ) |
| Net cash provided by (used in) financing activities | 1,584 | (30,123 ) | (42,271 ) |
| Net increase (decrease) in cash and cash equivalents | (708 ) | (3,601 ) | 1,938 |

BLUEKNIGHT ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

| | | | |
|---|---|---|---|
| Cash and cash equivalents at beginning of period | 5,548 | 4,840 | 1,239 |
| Cash and cash equivalents at end of period | $4,840 | $1,239 | $3,177 |
| | | | |
| Supplemental disclosure of cash flow information: | | | |
| Increase in accounts payable related to purchase of property, plant and equipment | $1,159 | $2,932 | $1,195 |
| Increase in accrued liabilities related to insurance premium financing agreement | $407 | $1,278 | $1,580 |
| Non-cash issuance of common units in settlement of the Class Action Litigation (see Note 3) | $— | $5,200 | $— |
| Settlement of rights offering liability | $— | $8,559 | $— |
| Reclassification of fair value of debt conversion option at reacquisition date | $— | $(5,536 ) | $— |
| Capital contribution related to redemption of convertible debt (see Note 8) | $— | $2,375 | $— |
| Cash paid for interest, net of amounts capitalized | $42,108 | $16,817 | $10,441 |
| Cash paid for income taxes | $158 | $209 | $289 |

The accompanying notes are an integral part of these financial statements.

BLUEKNIGHT ENERGY PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

## 1. ORGANIZATION AND NATURE OF BUSINESS

Blueknight Energy Partners, L.P. (formerly SemGroup Energy Partners, L.P.) and subsidiaries (collectively, the "Partnership") is a publicly traded master limited partnership with operations in twenty-three states. The Partnership provides integrated terminalling, storage, processing, gathering and transportation services for companies engaged in the production, distribution and marketing of crude oil and asphalt products. The Partnership manages its operations through four operating segments: (i) crude oil terminalling and storage services, (ii) crude oil pipeline services, (iii) crude oil trucking and producer field services and (iv) asphalt services. The Partnership's common units and preferred units, which represent limited partnership interests in the Partnership, are listed on the NASDAQ Global Market under the symbols "BKEP" and "BKEPP," respectively. The Partnership was formed in February of 2007 as a Delaware master limited partnership initially to own, operate and develop a diversified portfolio of complementary midstream energy assets.

## 2. BASIS OF PRESENTATION

The accompanying financial statements have been prepared assuming that the Partnership will continue as a going concern. The financial statements have been prepared in accordance with accounting principles and practices generally accepted in the United States of America ("GAAP"). All significant intercompany accounts and transactions have been eliminated in the preparation of the accompanying financial statements. Certain reclassifications have been made in the consolidated financial statements for the years ended December 31, 2010 and 2011 to conform to the 2012 financial statement presentation. Gain on sale of assets was reclassified from operating expenses to a separate component of operating income, and certain assets were reclassified from pipelines and facilities to storage and terminal facilities. The reclassifications have no impact on net income.

## 3. RECENT EVENTS

On October 25, 2010, the Partnership entered into a Global Transaction Agreement by and among the Partnership, Blueknight Energy Partners, G.P., L.L.C., which is the Partnership's general partner (the "General Partner"), Vitol ("Vitol" refers to Vitol Holding B.V., its affiliates and subsidiaries other than the Partnership's general partner and the Partnership) and Charlesbank ("Charlesbank" refers to Charlesbank Capital Partners, LLC, its affiliates and subsidiaries other than the Partnership's general partner and the Partnership), pursuant to which the Partnership effected a refinancing of its existing debt. The Global Transaction Agreement contemplated three events comprised of Phase I Transactions, a unitholder vote and Phase II Transactions. Phase I transactions were completed concurrently with the execution of the Global Transaction Agreement. For a detailed description of the Global Transaction Agreement, see the Partnership's 2010 Form 10-K.

On May 12, 2011, the Partnership, the General Partner, Vitol and Charlesbank entered into the First Amendment to Global Transaction Agreement (the "Amendment") pursuant to which the Unitholder Vote Transactions and the Phase II Transactions contemplated in the Global Transaction Agreement were modified.

Pursuant to the Global Transaction Agreement, as amended by the Amendment, the General Partner filed a definitive proxy statement with the Securities and Exchange Commission (the "SEC") relating to a special meeting (the "Unitholder Meeting") that occurred on September 14, 2011 during which the Partnership's unitholders considered and voted upon (i) certain amendments to the Partnership's partnership agreement (the "Partnership Agreement Amendment Proposal") as more fully set forth below and (ii) an amendment to the General Partner's Long-Term Incentive Plan to increase the number of common units issuable under such plan by 1,350,000 common units from 1,250,000 common units to

2,600,000 common units (the “LTIP Proposal”). Pursuant to the Partnership Agreement Amendment Proposal, the Partnership’s partnership agreement would be amended to:

- reset (1) the minimum quarterly distribution to $0.11 per unit per quarter from $0.3125 per unit per quarter, (2) the first target distribution to $0.1265 per unit per quarter from $0.3594 per unit per quarter, (3) the second target distribution to $0.1375 per unit per quarter from $0.3906 per unit per quarter and (4) the third target distribution to $0.1825 per unit per quarter from $0.4688 per unit per quarter;
- waive the cumulative common unit arrearage;
- remove provisions in the partnership agreement relating to the subordinated units, including concepts such as a subordination period (and any provisions that expressly apply only during the subordination period) and common unit arrearage, in connection with the transfer to the Partnership, and its subsequent cancellation, of all of the Partnership’s outstanding subordinated units;

- provide that distributions shall not accrue or be paid to the holders of the Partnership's incentive distribution rights for an eight quarter period beginning with the quarter in which the special meeting occurs;
- provide that during the period beginning on the date of this special meeting and ending on June 30, 2015 (the "Senior Security Restriction Period"), the Partnership will not issue any class or series of partnership securities that, with respect to distributions on such partnership securities or distributions upon liquidation of the Partnership, ranks senior to the common units during the Senior Security Restriction Period, or "Senior Securities", without the consent of the holders of at least a majority of the outstanding common units (excluding the common units held by the General Partner and its affiliates and excluding any Senior Securities that are convertible into common units), subject to certain exceptions; and
- make certain other amendments relating to the conversion of the Partnership's Series A Preferred Units (the "Preferred Units").

On September 14, 2011, the Partnership's unitholders approved the proposals outlined above. As a result, (i) the General Partner adopted the Fourth Amended and Restated Agreement of Limited Partnership of the Partnership (the "Amended and Restated Partnership Agreement") to reflect the approval of the Partnership Agreement Amendment Proposal, (ii) Vitol and Charlesbank transferred all of the Partnership's outstanding subordinated units to the Partnership and the Partnership cancelled such subordinated units and (iii) the Partnership was obligated to undertake an approximately $77 million rights offering.

On October 3, 2011, the Partnership commenced the rights offering. Pursuant to the terms of the rights offering, the Partnership distributed to its common unitholders of record as of the close of business on September 27, 2011, 0.5412 rights for each outstanding common unit, with each whole right entitling the holder to acquire, for a subscription price of $6.50, a newly issued Preferred Unit. The rights offering expired on October 31, 2011.

The rights offering was over-subscribed and, accordingly, on November 9, 2011, the Partnership issued a total of 11,846,990 Preferred Units to unitholders that exercised their rights. The Partnership received net proceeds of approximately $77 million from the rights offering. The net proceeds from the rights offering, after deducting expenses, were used to redeem convertible debentures in the aggregate principal amount of $50 million plus accrued interest thereon that the Partnership issued to Vitol and Charlesbank (the "Convertible Debentures") and to repurchase an aggregate of 3,225,494 Preferred Units from Vitol and Charlesbank. The Preferred Units are listed on the NASDAQ Global Market under the symbol "BKEPP."

On May 3, 2011, the Partnership entered into a Stipulation of Settlement (the "Stipulation") to settle the consolidated securities class action litigation, In Re: SemGroup Energy Partners, L.P. Securities Litigation, Case No. 08-MD-1989-GKF-FHM (the "Class Action Litigation"), pending in the U.S. District Court for the Northern District of Oklahoma. As set forth more fully in the Stipulation, upon final approval by the court, among other things, the shareholder class received a total payment of approximately $28.0 million from the defendants. On June 9, 2011, the Court entered an order preliminarily approving, subject to further consideration at a settlement hearing, the proposed settlement pursuant to the Stipulation involving, among other things, a dismissal of the Class Action Litigation with prejudice. The Court held a hearing on October 5, 2011 and granted final approval of the proposed settlement and issued a final judgment (the "Judgment") in accordance with the Stipulation. The Judgment became final on November 7, 2011.

On November 28, 2011, the Partnership received a letter from the staff of the Securities and Exchange Commission (the "SEC") notifying the Partnership that the staff has completed its investigation of the Partnership and does not intend to recommend any enforcement action by the SEC.

On January 10, 2012, the Partnership announced the future resignation of the Chief Executive Officer of the Partnership's general partner, Mr. James Dyer. Mr. Dyer remained as Chief Executive Officer until his successor, Mr.

Mark A. Hurley was appointed by the Board of Directors (the "Board") of the General Partner as his successor, effective as of September 30, 2012. Mr. Dyer also continued to serve on the Board until that time, after which Mr. Francis Brenner of Vitol was appointed to take his place.

## 4. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

USE OF ESTIMATES -The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts and disclosure of contingencies. Management makes significant estimates including: (1) allowance for doubtful accounts receivable; (2) estimated useful lives of assets, which impacts depreciation; (3) estimated cash flows and fair values inherent in impairment tests; (4) accruals related to revenues and expenses; (5) the estimated fair value of financial instruments;

and (6) liability and contingency accruals. Although management believes these estimates are reasonable, actual results could differ from these estimates.

CASH AND CASH EQUIVALENTS - The Partnership includes as cash and cash equivalents, cash and all investments with maturities at date of purchase of three months or less which are readily convertible into known amounts of cash.

ACCOUNTS RECEIVABLE - The majority of the Partnership's accounts receivable relates to its trucking and producer field services and asphalt services activities. Accounts receivable included in the balance sheets are reflected net of the allowance for doubtful accounts of $0.5 million at December 31, 2011 and 2012.

The Partnership reviews all outstanding accounts receivable balances on a monthly basis and records a reserve for amounts that the Partnership expects will not be fully recovered. Although the Partnership considers its allowance for doubtful trade accounts receivable to be adequate, there is no assurance that actual amounts will not vary significantly from estimated amounts.

PROPERTY, PLANT AND EQUIPMENT - Property, plant and equipment are recorded at cost. Expenditures for maintenance and repairs that do not add capacity or extend the useful life of an asset are expensed as incurred. The carrying value of the assets is based on estimates, assumptions and judgments relative to useful lives and salvage values. As assets are disposed of, the cost and related accumulated depreciation are removed from the accounts, and any resulting gain or loss is included in operating income in the statements of operations.

Depreciation is calculated using the straight-line method, based on estimated useful lives of the assets. These estimates are based on various factors including age (in the case of acquired assets), manufacturing specifications, technological advances and historical data concerning useful lives of similar assets. Uncertainties that impact these estimates include changes in laws and regulations relating to restoration and abandonment requirements, economic conditions and supply and demand in the area. When assets are put into service, management makes estimates with respect to useful lives and salvage values that it believes are reasonable. However, subsequent events could cause management to change its estimates, thus impacting the future calculation of depreciation.

The Partnership has contractual obligations to perform dismantlement and removal activities in the event that some of its asphalt product and residual fuel oil terminalling and storage assets are abandoned (see Note 16). Such obligations are recognized in the period incurred if reasonably estimable.

IMPAIRMENT OF LONG-LIVED ASSETS AND OTHER INTANGIBLE ASSETS - Long-lived assets with recorded values that are not expected to be recovered through future cash flows are written-down to estimated fair value. A long-lived asset is tested for impairment when events or circumstances indicate that its carrying value may not be recoverable. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the carrying value exceeds the sum of the undiscounted cash flows, an impairment loss equal to the amount by which the carrying value exceeds the fair value of the asset is recognized. Fair value is generally determined from estimated discounted future net cash flows. The Partnership recognized an impairment charge of $0.8 million during the year ended December 31, 2010 related to an asphalt facility located in Morehead City, North Carolina that was sold in April of 2010. The Partnership recognized impairment charges of $0.5 million and $0.3 million during the year ended December 31, 2011 related to an office building located in St. Louis, Missouri and an office building located in Abilene, Texas, respectively. As of December 31, 2011, the office building in Abilene, Texas was classified as held for sale, and the Partnership subsequently sold this asset in January of 2012. The Partnership recognized total fixed asset impairment charges of $1.8 million during the year ended December 31, 2012 that included $1.0 million related to Oklahoma gathering pipeline assets and $0.7 million related to a Bay City, Michigan residual fuel oil facility.

Acquired customer relationships and non-compete agreements are capitalized and amortized over useful lives ranging from 4 to 20 years using the straight-line method of amortization. An impairment loss is recognized for definite-lived intangibles if the carrying amount of an intangible asset is not recoverable and its carrying amount exceeds its fair value. No impairment charge was recognized in the twelve months ended December 31, 2010 and 2011 with respect to amortizable intangibles. In December 2012, the Partnership recognized an impairment loss of $0.1 million related to a non-compete agreement due to the death of the counterpart to the agreement.

DEBT ISSUANCE COSTS - Costs incurred in connection with the issuance of long-term debt related to the Partnership’s credit facilities are capitalized and amortized using the straight-line method over the term of the related debt. Use of the straight-line method does not differ materially from the “effective interest” method of amortization.

GOODWILL - Goodwill represents the excess of the cost of acquisitions over the amounts assigned to assets acquired and liabilities assumed. Goodwill is not amortized but is tested annually for impairment and when events and circumstances warrant an interim evaluation. Goodwill is tested for impairment at a level of reporting referred to as a reporting unit. The Partnership has four reporting units comprised of (i) its crude oil terminalling and storage services, (ii) its crude oil pipeline services, (iii) its crude oil trucking and producer field services, and (iv) its asphalt services. The Partnership has recorded goodwill of $6.3 million related to its crude oil pipeline services reporting unit and $0.9 million related to its crude oil trucking and producer field services reporting unit. If the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is considered not impaired. The impairment test is generally based on the estimated discounted future net cash flows of the respective reporting unit, utilizing discount rates and other factors in determining the fair value of the reporting unit. Inputs in our estimated discounted future net cash flows include existing and estimated future asset utilization, estimated growth rates in future cash flows, and estimated terminal values (these are all considered level 3 inputs). The Partnership did not recognize any impairment of goodwill, including in its most recent impairment test conducted in the fourth quarter of 2012.

ENVIRONMENTAL MATTERS - Liabilities for loss contingencies, including environmental remediation costs, arising from claims, assessments, litigation, fines, penalties and other sources are charged to expense when it is probable that a liability has been incurred and the amount of the assessment and/or remediation can be reasonably estimated. The Partnership does not have any recorded loss contingencies related to environmental matters as of December 31, 2012.

REVENUE RECOGNITION - The Partnership's revenues consist of (i) terminalling and storage revenues, (ii) gathering, transportation and producer field services revenues and (iii) fuel surcharge revenues.

Terminalling and storage revenues consist of (i) storage service fees from actual storage used on a month-to-month basis; (ii) storage service fees resulting from short-term and long-term contracts for committed space that may or may not be utilized by the customer in a given month; and (iii) terminal throughput service charges to pump crude oil to connecting carriers or to deliver asphalt product out of the Partnership's terminals. Terminal throughput service charges are recognized as the crude oil exits the terminal and is delivered to the connecting crude oil carrier or third-party terminal and as the asphalt product is delivered out of the Partnership's terminal. Storage service revenues are recognized as the services are provided and the amounts earned on a monthly basis.

Gathering and transportation services revenues consist of service fees recognized for the gathering of crude oil for the Partnership's customers and the transportation of the crude oil to refiners, to common carrier pipelines for ultimate delivery to refiners, or to terminalling and storage facilities owned by the Partnership and others. Revenue for the gathering and transportation of crude oil is recognized when the service is performed and is based upon regulated and non-regulated tariff rates and the related transport volumes. Producer field services revenue consists of a number of services ranging from gathering condensates from natural gas producers to hauling produced water to disposal wells. Revenue for producer field services is recognized when the service is performed.

Fuel surcharge revenues are comprised of revenues recognized for the reimbursement of fuel and power consumed to operate the Partnership's asphalt product storage tanks and terminals. The Partnership recognizes fuel surcharge revenues in the period in which the related fuel and power expenses are incurred.

INCOME AND OTHER TAXES - For federal and most state income tax purposes, the majority of income, gains, losses, expenses, deductions and tax credits generated by the Partnership flow through to the unitholders of the Partnership. In 2007, the state of Texas implemented a partnership-level tax based on a percentage of the revenue earned for services provided in the state of Texas. The Partnership has estimated its liability related to this tax to be $0.3 million at both December 31, 2011 and 2012, which is reported as a provision for income taxes on its consolidated statements of operations. See Note 20 for a discussion of certain risks related to the Partnership's ability to be treated as a partnership for federal income tax purposes.

STOCK BASED COMPENSATION - The Partnership's general partner adopted the Blueknight Energy Partners G.P. L.L.C. Long-Term Incentive Plan (the "LTIP"). The compensation committee of the Board administers the LTIP. The LTIP authorizes the grant of an aggregate of 2.6 million common units deliverable upon vesting. Although other types of awards are contemplated under the LTIP, awards issued to date include "phantom" units, which convey the right to receive common units upon vesting, and "restricted" units, which are grants of common units restricted until the time of vesting. Certain of the phantom unit awards also include distribution equivalent rights ("DERs"). A DER entitles the grantee to a cash payment equal to the cash distribution paid on an outstanding common unit prior to the vesting date of the underlying award. Cash distributions paid on DERs are accounted for as partnership distributions. Recipients of restricted units are entitled to receive cash distributions paid on common units during the vesting period.

The Partnership classifies unit award grants as either equity or liability awards. All award grants made under the Plan from its inception through December 31, 2012 have been classified as equity awards. Fair value for award grants classified as equity is determined on the grant date of the award and this value is recognized as compensation expense ratably over the requisite service period of unit award grants, which generally is the vesting period. Fair value for equity awards is calculated as the closing price of the Partnership's common units representing limited partner interests in the Partnership ("common units") on the grant date and is reduced by the present value of estimated cash distributions to be paid on common units during the vesting period to the extent a unit award does not include DERs. Compensation expense related to unit-based payments is included in operating and general and administrative expenses on the Partnership's consolidated statements of operations.

FAIR VALUE OF FINANCIAL INSTRUMENTS - The Partnership measures all financial instruments, including derivatives embedded in other contracts, at fair value and recognizes them in the consolidated balance sheet as an asset or a liability, depending on its rights and obligations under the applicable contract. The changes in the fair value of financial instruments are recognized currently in earnings, in other (income) expenses, on the consolidated statement of operations.

5. PROPERTY, PLANT AND EQUIPMENT

| | Estimated Useful Lives (Years) | December 31, 2011 | 2012 |
|---|---|---|---|
| | | (dollars in thousands) | |
| Land | N/A | $16,601 | $16,405 |
| Land improvements | 10-20 | 5,671 | 6,287 |
| Pipelines and facilities | 5-30 | 94,132 | 101,392 |
| Storage and terminal facilities | 10-35 | 227,740 | 232,102 |
| Transportation equipment | 3-10 | 20,615 | 18,003 |
| Office property and equipment and other | 3-20 | 22,901 | 26,009 |
| Pipeline linefill and tank bottoms | N/A | 7,458 | 5,993 |
| Construction-in-progress | N/A | 6,539 | 14,766 |
| Property, plant and equipment, gross | | 401,657 | 420,957 |
| Accumulated depreciation | | (135,302) | (153,216) |
| Property, plant and equipment, net | | $266,355 | $267,741 |

Depreciation expense for the twelve months ended December 31, 2010, 2011 and 2012 was $21.4 million, $22.7 million and $23.0 million, respectively. In the twelve months ended December 31, 2010, 2011 and 2012, the Partnership recorded asset impairment expense of $0.8 million, $0.9 million and $1.8 million, respectively.

6. INTANGIBLES AND OTHER ASSETS, NET

Other assets, net of accumulated amortization, consist of the following (in thousands):

| | December 31, 2011 | 2012 |
|---|---|---|
| Customer relationships | $661 | $661 |
| Non-compete agreements | 200 | — |
| Deposits | 506 | 476 |
| Prepaid insurance | 880 | 518 |
| Other prepaid expenses | 34 | 70 |
| Intangibles and other assets, gross | 2,281 | 1,725 |
| Accumulated amortization of intangible assets | (90) | (69) |
| Intangibles and other assets, net | $2,191 | $1,656 |

Amortization expense related to intangibles was less than $0.1 million for the twelve months ended December 31, 2010 and was $0.1 million for each of the twelve months ended December 31, 2011 and 2012. The estimated aggregate amortization expense on amortizable intangible assets currently owned by the Partnership is as follows (in thousands):

| | |
|---|---|
| For twelve months ending: | |
| December 31, 2013 | $33 |
| December 31, 2014 | 33 |
| December 31, 2015 | 33 |
| December 31, 2016 | 33 |
| December 31, 2017 | 33 |
| Thereafter | 427 |
| Total estimated aggregate amortization expense | $592 |

In connection with the acquisition of a producer field services business in December 2010, the Partnership recorded intangibles for customer relationships of $0.7 million and a non-compete agreement of $0.2 million. Both of these assets relate to the crude oil trucking and producer field services operating segment. The customer relationships are being amortized over twenty years. In December 2012, the non-compete agreement was determined to be impaired due to the death of the counterpart to the agreement and an impairment expense of $0.1 million was recognized. This expense is included in operating expenses on the Partnership's consolidated statements of operations.

7. ACQUISITIONS

In December of 2010, the Partnership acquired a company engaged in producer field services located in Dumas, Texas, for total consideration of approximately $5.7 million. The Partnership accounted for this acquisition as a business combination in accordance with the provisions of ASC 805 - Business Combinations. The purchase price allocation is comprised of $4.1 million of fixed assets, consisting primarily of vehicles, buildings, and equipment; $0.9 million of intangible assets related to customer relationships and non-compete agreements and $0.9 million of goodwill. Goodwill recognized in conjunction with this acquisition is reflective of the synergies the Partnership expects to realize as a result of combining this business with its existing producer field services business.

8. DEBT

On October 25, 2010, the Partnership entered into a new credit agreement, which includes a $200.0 million term loan facility and a $75.0 million revolving loan facility. On April 5, 2011, the Partnership entered into a Joinder Agreement whereby the Partnership's revolving credit facility was increased from $75.0 million to $95.0 million. As of March 7, 2013, approximately $200.0 million of term loan borrowings, $32.0 million of revolver borrowings and $0.5 million of letters of credit were outstanding under the credit facility, leaving the Partnership with approximately $62.5 million available capacity for additional revolver borrowings and letters of credit under the credit facility, although the Partnership's ability to borrow such funds may be limited by the financial covenants in the credit facility. Vitol is a lender under the credit agreement and has committed to loan the Partnership $15.0 million pursuant to such agreement. The proceeds of loans made under the credit agreement may be used for working capital and other general corporate purposes of the Partnership.

On November 2, 2012, the Partnership amended its credit facility to permit Mr. Hurley to receive a non-voting economic interest in Blueknight GP Holding, LLC ("HoldCo"), the owner of the Partnership's general partner. Mr. Hurley's interest in HoldCo will vest over a five year period and entitle Mr. Hurley, to the extent vested, to (i) 2% of the total amount of proceeds and/or distributions in excess of $100,000,000 received by HoldCo in connection with a transaction resulting in a change of control of the Partnership, and (ii) 2% of the portion of any interim quarterly distribution received by HoldCo in excess of $1,250,000. (See Note 14.)

The credit agreement is guaranteed by all of the Partnership's existing subsidiaries. Obligations under the credit agreement are secured by first priority liens on substantially all of the Partnership's assets and those of the guarantors, including all material pipeline, gathering and processing assets, all material storage tanks and asphalt facilities, all material working capital assets and a pledge of all of the Partnership's equity interests in its subsidiaries.

The credit agreement includes procedures for additional financial institutions to become revolving lenders, or for any existing lender to increase its revolving commitment thereunder, subject to an aggregate maximum of $200.0 million for all revolving loan commitments under the credit agreement.

The credit agreement will mature on October 25, 2014, and all amounts outstanding under the credit agreement will become due and payable on such date. The Partnership may prepay all loans under the credit agreement at any time without premium or penalty (other than customary LIBOR breakage costs), subject to certain notice requirements. The credit agreement requires mandatory prepayments of amounts outstanding thereunder with the net proceeds of certain asset sales, casualty events and debt incurrences, and, in certain circumstances, with a portion of the Partnership's excess cash flow (as defined in the credit agreement). These mandatory prepayments will be applied to the term loan under the credit agreement until it is repaid in full, then applied to reduce commitments under the revolving loan facility.

Borrowings under the credit agreement bear interest, at the Partnership's option, at either (i) the ABR (the highest of the administrative agent's prime rate, the federal funds rate plus 0.5%, or the one-month eurodollar rate (as defined in the credit agreement) plus 1.0%), plus an applicable margin that ranges from 3.0% to 3.5%, or (ii) the eurodollar rate plus an applicable margin that ranges from 4.0% to 4.5%, in each case depending on the Partnership's consolidated total leverage ratio (as defined in the credit agreement). The Partnership pays a per annum fee on all letters of credit issued under the credit agreement, which fee equals the applicable margin for loans accruing interest based on the eurodollar rate, and the Partnership pays a commitment fee of 0.5% per annum on the unused availability under the credit agreement. The credit agreement does not have a floor for the ABR or the eurodollar rate. In connection with entering into the credit agreement, the Partnership paid certain upfront fees to the lenders thereunder, and the Partnership paid certain arrangement and other fees to the arranger and administrative agent of the credit agreement. Vitol received its pro rata portion of such fees as a lender under the credit agreement.

In March 2013 the Partnership amended its credit facility to, among other things:

- eliminate the requirement that its consolidated total leverage ratio not exceed 4.00 to 1.00 for purposes of making distributions;
- increase the Partnership's ability to make investments in joint ventures and subsidiaries without such joint ventures and subsidiaries becoming guarantors under the credit facility; and
- permit the Partnership to include projected EBITDA from material projects (generally being the construction or expansion of any capital project the aggregate budgeted capital cost of which exceeds $5.0 million) in our EBITDA for purposes of calculating compliance with the credit facility's minimum consolidated interest coverage ratio and maximum consolidated total leverage ratio. The amount of projected EBITDA from material projects that is included in such financial covenant calculations is subject to the credit facility administrative agent's approval, and the aggregate amount of all material project EBITDA adjustments during any period is limited to 15% of the total actual consolidated EBITDA for such period.

In connection with entering into the March 2013 credit facility amendment the Partnership paid a fee to the consenting lenders.

The credit agreement 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 consolidated total leverage ratio is 4.50 to 1.00 for the fiscal quarter ending December 31, 2012 and each future fiscal quarter thereafter. The minimum permitted consolidated interest coverage ratio (as defined in the credit agreement) is 3.00 to 1.00 for each future fiscal quarter.

In addition, the credit agreement contains various covenants that, among other restrictions, limit the Partnership's ability to:

- create, issue, incur or assume indebtedness;
- create, incur or assume liens;
- engage in mergers or acquisitions;
- sell, transfer, assign or convey assets;
- repurchase the Partnership's equity, make distributions to unitholders and make certain other restricted payments;
- make investments;

- modify the terms of the Convertible Debentures and certain other indebtedness, or prepay certain indebtedness;
- engage in transactions with affiliates;
- enter into certain hedging activities;
- enter into certain burdensome agreements;
- change the nature of the Partnership’s business;
- enter into operating leases; and
- make certain amendments to the Partnership’s partnership agreement.

At December 31, 2012, the Partnership's leverage ratio was 3.04 to 1.00 and the interest coverage ratio was 6.73 to 1.00. The Partnership was in compliance with all covenants of its credit agreement as of December 31, 2012.

As of December 31, 2012, the credit agreement, permitted the Partnership to make quarterly distributions of available cash (as defined in the Partnership's partnership agreement) to unitholders so long as: (i) no default or event of default exists under the credit agreement, (ii) the Partnership has, on a pro forma basis after giving effect to such distribution, at least $10.0 million of availability under the revolving loan facility, and (iii) the Partnership's consolidated total leverage ratio, on a pro forma basis, would not be greater than 4.50 to 1.00. In March 2013, the credit agreement was amended to, among other things, eliminate the requirement that our consolidated total leverage ratio not exceed 4.50 to 1.00. The Partnership is currently allowed to make distributions to its unitholders in accordance with these covenants; however, the Partnership will only make distributions to the extent it has sufficient cash from operations after establishment of cash reserves as determined by the General Partner in accordance with the Partnership's cash distribution policy, including the establishment of any reserves for the proper conduct of the Partnership's business. See Note 10 for additional information regarding distributions.

Each of the following is an event of default under the credit agreement:

- failure to pay any principal, interest, fees, expenses or other amounts when due;
- failure to meet the quarterly financial covenants;
- failure to observe any other agreement, obligation or covenant in the credit agreement or any related loan document, subject to cure periods for certain failures;
- the failure of any representation or warranty to be materially true and correct when made;
- the Partnership's, or any of its subsidiaries', default under other indebtedness that exceeds a threshold amount;
- judgments against the Partnership or any of its subsidiaries, in excess of a threshold amount;
- certain material ERISA events involving the Partnership or any of its subsidiaries;
- bankruptcy or other insolvency events involving the Partnership or any of its subsidiaries; and
- a change of control (as defined in the credit agreement).

If an event of default relating to bankruptcy or other insolvency events occurs, all indebtedness under the credit agreement will immediately become due and payable. If any other event of default exists under the credit agreement, the lenders may accelerate the maturity of the obligations outstanding under the credit agreement and exercise other rights and remedies. In addition, if any event of default exists under the credit agreement, the lenders may commence foreclosure or other actions against the collateral.

If any default occurs under the credit agreement, or if the Partnership is unable to make any of the representations and warranties in the credit agreement, the Partnership will be unable to borrow funds or have letters of credit issued under the credit agreement.

It will constitute a change of control under the credit agreement if either Vitol or Charlesbank ceases to own, directly or indirectly, exactly 50% of the membership interests of the General Partner or if the General Partner ceases to be controlled by both Vitol and Charlesbank.

The Partnership capitalized debt issuance costs of approximately $1.1 million in 2010 related to the Partnership's prior credit facility, which was being amortized on a straight-line basis through June 2011. Upon the execution of the new credit agreement, the Partnership wrote off $2.9 million in debt issuance costs related to the prior credit facility, leaving a remaining balance of $0.6 million ascribed to those lenders with commitments under both the prior credit facility and the new credit facility. The Partnership capitalized $6.4 million and $0.3 million in debt issuance costs related to the new credit facility in 2010 and 2011, respectively. The Partnership did not incur any debt issuance costs in the twelve months ended December 31, 2012. Interest expense related to debt issuance cost amortization for the twelve months ended December 31, 2010, 2011 and 2012 was $4.3 million, $2.0 million and $1.8 million, respectively.

During the twelve months ended December 31, 2012, the weighted average interest rate under the credit agreement incurred by the Partnership was 4.51%, and the total weighted average interest rate, including interest associated with the ENPS Throughput Agreement (as defined in Note 12), was 5.48%, resulting in interest expense of approximately $11.7 million. During the twelve months ended December 31, 2010, 2011 and 2012, the Partnership capitalized interest of $3.8 million, less than $0.1 million, and $0.2 million, respectively.

In October 2010 the Partnership issued convertible subordinated debentures in a private placement in the aggregate principal amount of $50.0 million. If not previously redeemed, the convertible subordinated debentures, including all outstanding principal and unpaid interest, would have converted to Preferred Units on December 31, 2011. Upon issuance, this conversion feature was considered an embedded derivative, which the Partnership was required to bifurcate and carry at its fair value each reporting period. In connection with the establishment of the conversion price for the Preferred Units following the special meeting of the Partnership's unitholders in September 2011, the conversion option was deemed to meet the scope exception for certain contracts involving an entity's own equity in ACS 815-Derivatives and Hedging, and, therefore, the Partnership reclassified the embedded derivative as partners' capital in the third quarter of 2011. The Partnership redeemed the convertible subordinated debentures on November 9, 2011.

Changes to the fair value of the embedded derivative are reflected on the Partnership's consolidated statements of operations as "Change in fair value of embedded derivative within convertible debt." The value of the embedded derivative was contingent on changes in the expected fair value of the Partnership's preferred units. The Partnership recorded a loss of $6.7 million and a gain of $20.2 million due to the change in the fair value of this embedded derivative in the twelve months ended December 31, 2010 and 2011, respectively.

In addition, the recording of the embedded derivative liability related to the convertible subordinated debentures resulted in the Partnership recording a $20.9 million debt discount on the convertible subordinated debentures. The debt discount was being amortized to interest expense through the mandatory conversion date of December 31, 2011, using the effective interest rate method until the redemption of the convertible subordinated debentures on November 9, 2011. Upon redemption, the remaining unamortized debt discount was considered in the calculation of a $2.4 million extinguishment gain, which was determined to represent a capital transaction and, therefore, was recorded as a capital contribution to the Partnership by the Partnership's general partner. For the purpose of calculating net income per limited partner unit, this amount was added back to net loss available to limited partners as it represents the recovery of a portion of the additional financing costs resulting from bifurcation of the conversion option and related discount on the convertible subordinated debentures. The Partnership recognized non-cash interest expense of $3.2 million and $15.1 million in the twelve months ended December 31, 2010 and 2011, respectively, due to the amortization of the debt discount.

## 9. NET INCOME PER LIMITED PARTNER UNIT

For purposes of calculating earnings per unit, the excess of distributions over earnings or excess of earnings over distributions for each period are allocated to the entities' general partner based on the general partner's ownership interest at the time. The following sets forth the computation of basic and diluted net income (loss) per common and subordinated unit (in thousands, except per unit data):

| | Year ended December 31, | | |
|---|---|---|---|
| | 2010 | 2011 | 2012 |
| Net income (loss) | $(23,796) | $33,475 | $31,565 |
| General partner interest in net income (loss) | (470) | 912 | 774 |
| Preferred interest in net income | — | 16,446 | 21,564 |
| Accretion of discount on increasing rate Preferred Units | — | 2,243 | — |
| Beneficial conversion feature attributable to preferred units | 8,114 | 43,259 | 1,853 |
| Beneficial conversion feature attributable to repurchased Preferred Units | — | (6,892) | — |
| Gain on extinguishment attributable to redemption of convertible debt, recorded as a capital transaction | — | (2,375) | — |
| Income (loss) available to limited partners | $(31,440) | $(20,118) | $7,374 |

Basic and diluted weighted average number of units:

| | | | |
|---|---|---|---|
| Common units | 21,744 | 22,059 | 22,668 |
| Subordinated units[1] | 12,571 | 8,817 | — |
| Restricted and phantom units | 617 | 380 | 688 |
| | | | |
| Basic and diluted net income (loss) per common unit | $(0.91) | $(0.61) | $0.32 |
| Basic and diluted net loss per subordinated unit[1] | $(0.91) | $(0.52) | $— |

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(1) On September 14, 2011, Vitol and Charlesbank transferred all of the Partnership's outstanding subordinated units to the Partnership and the Partnership canceled such subordinated units.

10. PARTNERS' CAPITAL AND DISTRIBUTIONS

In accordance with the terms of its partnership agreement, each quarter the Partnership distributes all of its available cash (as defined in the partnership agreement) to its unitholders. Generally, distributions are allocated: first, 98% to the Series A Preferred Unitholders and 2% to its general partner until the Partnership distributes for each Series A Preferred Unit an amount equal to the Series A quarterly distribution amount discussed below; then 98% to the Series A Preferred Unitholders and 2% to its general partner until the Partnership distributes for each Series A Preferred Unit an amount equal to any Series A cumulative distribution arrearage; and, thereafter, 98% to the common unitholders and 2% to its general partner. Distributions are also paid to the holders of restricted units and phantom units as disclosed in Note 13.

Pursuant to the terms of the Global Transaction Agreement, the Partnership issued and sold 10,769,231 Preferred Units to each Purchaser (or 21,538,462 Preferred Units in the aggregate) for a cash purchase price of $6.50 per Preferred Unit, resulting in total gross proceeds of approximately $140 million.

These Preferred Units are convertible at the holders' option into common units. The Preferred Units were issued at a discount to the market price of the common units into which they are convertible. This discount totaling $54.5 million represents a beneficial conversion feature and is reflected as an increase in common and subordinated unitholders' capital and a decrease in Preferred Unitholders' capital to reflect the fair value of the Preferred Units at issuance on the Partnership's consolidated statement of changes in partners' capital for the twelve months ended December 31, 2010. The beneficial conversion feature is considered a dividend and has been distributed ratably from the issuance date of October 25, 2010 through the first conversion date which is January 2012, resulting in an increase in preferred capital and a decrease in common and subordinated unitholders' capital. The impact of the beneficial conversion feature is also included in earnings per unit for the twelve months ended December 31, 2010, 2011 and 2012.

Holders of the Preferred Units are entitled to quarterly distributions of 2.125% per unit per quarter (or 8.5% per unit on an annual basis) for each quarter during the one year period after the date of issuance of the Preferred Units (pro-rated with respect to the period commencing on the date of issuance and ending on December 31, 2010 based on the number of days in such period). In the case of any quarter beginning one year after the date of the issuance of the Preferred Units, the holders of the Preferred Units were entitled to quarterly distributions of 4.375% per unit per quarter (or 17.5% per unit on an annual basis) but this amount was decreased to 2.75% per unit per quarter (or 11.0% per unit on an annual basis) upon affirmative vote of the unitholder proposals discussed in Note 3. The unitholders approved the proposals in September 2011. If the Partnership fails to pay in full any distribution on the Preferred Units, the amount of such unpaid distribution will accrue and accumulate from the last day of the quarter for which such distribution is due until paid in full.

On October 3, 2011, the Partnership commenced the rights offering. Pursuant to the terms of the rights offering, the Partnership distributed to its common unitholders of record as of the close of business on September 27, 2011, 0.5412 rights for each outstanding common unit, with each whole right entitling the holder to acquire, for a subscription price of $6.50, a newly issued Preferred Unit. The rights offering expired on October 31, 2011.

The rights offering was over-subscribed and, accordingly, on November 9, 2011, the Partnership issued a total of 11,846,990 Preferred Units to unitholders that exercised their rights. The Partnership received net proceeds of approximately $77 million from the rights offering. The net proceeds from the rights offering, after deducting expenses, were used to redeem convertible debentures in the aggregate principal amount of $50 million plus accrued interest thereon that the Partnership issued to Vitol and Charlesbank and to repurchase an aggregate of 3,225,494

Preferred Units from Vitol and Charlesbank.

The Partnership paid distributions of $11.4 million during 2011 on the Preferred Units for the portion of the quarter ended December 31, 2010 during which the Preferred Units were outstanding and for the quarters ending March 31, 2011, June 30, 2011 and September 30, 2011. The Partnership paid distributions totaling $21.2 million during 2012 on the Preferred Units for the quarters ending December 31, 2011, March 31, 2012, June 30, 2012 and September 30, 2012. On January 23, 2013, the Board approved a distribution of $0.17875 per Preferred Unit, or a total distribution of $5.4 million, for the quarter ending December 31, 2012. The Partnership paid this distribution on the preferred units on February 14, 2013 to unitholders of record as of February 4, 2013.

The Partnership paid distributions totaling $10.3 million during 2012 on the common units for the quarters ending December 31, 2011, March 31, 2012, June 30, 2012 and September 30, 2012. Of the $10.3 million paid during 2012, approximately $0.2 million was paid to holders of phantom and restricted units under the Partnership’s long-term incentive plan. In addition, on January 23, 2013, the Board declared a cash distribution of $0.1150 per unit on its outstanding common units, a 2.2% increase over the previous quarter's distribution. The distribution was paid on February 14, 2013 to unitholders of record on February 4, 2013. The distribution is for the three months ended December 31, 2012. The total distribution paid was approximately $2.7 million, with approximately $2.6 million and $0.1 million paid to the Partnership's common unitholders and general partner, respectively, and less than $0.1 million paid to holders of phantom and restricted units pursuant to awards granted under the Partnership's long-term incentive plan.

11. MAJOR CUSTOMERS AND CONCENTRATION OF CREDIT RISK

For the twelve months ended December 31, 2012, Vitol accounted for 67% of crude oil terminalling and storage services revenue. Vitol, Valero Marketing and Supply Co. and ExxonMobil Corporation each accounted for at least 15% but no more than 30% of crude oil pipeline services revenue in 2012. Vitol and MV Purchasing, LLC accounted for at least 10% but not more than 30% of crude oil trucking and producer field services revenue in 2012. Ergon Asphalt & Emulsions, Heartland Asphalt Materials, Inc., NuStar Marketing LLC and Suncor Energy USA accounted for at least 10% but not more than 30% of asphalt services revenue in 2012. Vitol comprised 23% of total accounts receivable at December 31, 2012.

Financial instruments that potentially subject the Partnership to concentrations of credit risk consist principally of trade receivables. The Partnership's accounts receivable are primarily from producers, purchasers and shippers of crude oil and asphalt product and at times will include Vitol. This industry concentration has the potential to impact the Partnership's overall exposure to credit risk in that the customers may be similarly affected by changes in economic, industry or other conditions. The Partnership periodically reviews credit exposure and financial information of its counterparties.

12. RELATED PARTY TRANSACTIONS

The Partnership provides crude oil gathering, transportation, terminalling and storage services to Vitol. For the twelve months ended December 31, 2010, 2011 and 2012, the Partnership recognized revenues of $23.5 million, $44.1 million and $48.2 million, respectively, for services provided to Vitol. As of December 31, 2011 and 2012, the Partnership had receivables from Vitol of $3.9 million and $3.1 million, respectively. The Partnership also had a receivable from its General Partner of $0.5 million for both December 31, 2011 and 2012.

Vitol Omnibus Agreement

On February 15, 2010, the Partnership entered into an Omnibus Agreement (the "Vitol Omnibus Agreement") with Vitol. Pursuant to the Vitol Omnibus Agreement, the Partnership agreed to provide certain of its employees, consultants and agents (the "Designated Persons") to Vitol for use by Vitol's crude oil marketing division. In return, Vitol agreed to reimburse the Partnership in an amount equal to (i) the wages, salaries, bonuses, make whole payments, payroll taxes and the cost of all employee benefits of each Designated Person, in each case as adjusted to properly reflect the time spent by such Designated Person in the performance services for Vitol, (ii) all direct expenses, including, without limitation, any travel and entertainment expenses, incurred by each Designated Person in connection with such Designated Person's provision of services for Vitol, (iii) a monthly charge of $1,500.00 per Designated Person for each Designated Person that performs services for Vitol during any portion of such month, plus (iv) the sum of subsections (i) through (iii) above multiplied by 0.10. In addition, the Vitol Omnibus Agreement provides that if during any month any Designated Person has spent more than 80% of his time performing services for Vitol, then Vitol will have the right for the succeeding three months to request that such individual be transitioned directly to the employment of Vitol. During the twelve months ended December 31, 2010, 2011 and 2012 the Partnership received payments of $1.0 million, $1.6 million and $0.1 million, respectively, pursuant to the Vitol Omnibus Agreement. The Vitol Omnibus Agreement was reviewed and approved by the Board's conflicts committee in accordance with the Partnership’s procedures for approval of related party transactions and the provisions of the Partnership’s partnership agreement. The Partnership and Vitol terminated the Vitol Omnibus Agreement on March 27, 2012.

Vitol Storage Agreements

In connection with the Partnership’s acquisition of certain of its crude oil storage assets from SemCorp in May 2008, the Partnership was assigned from SemCorp a storage agreement with Vitol under which the Partnership provided crude oil storage services to Vitol (the “2008 Vitol Storage Agreement”). The initial term of the 2008 Vitol Storage Agreement was from June 1, 2008 through June 30, 2010. This agreement was amended in 2010 to extend the term of the agreement until June 1, 2011 and again in 2011 to extend the term of the agreement to June 1, 2012. Because Vitol was a third party (and not a related or affiliated party) at the time of entering into the 2008 Vitol Storage Agreement, such agreement was not approved by the Board or the Board’s conflicts committee in accordance with the Partnership’s procedures for approval of related party transactions. Vitol became a related party when it acquired the General Partner in November 2009 (the “Vitol Change of

Control"). Since the amendments occurred subsequent to the Vitol Change of Control, they were reviewed and approved by the Board's conflicts committee in accordance with the Partnership's procedures for approval of related party transactions and the provisions of the partnership agreement. The Partnership earned revenues of approximately $12.5 million, $13.2 million and $5.5 million from Vitol with respect to services provided pursuant to the 2008 Vitol Storage Agreement for the twelve months ended December 31, 2010, 2011 and 2012, respectively. The Partnership believes that the rates it charged Vitol under the 2008 Vitol Storage Agreement were fair and reasonable to the Partnership and its unitholders and were comparable with the rates the Partnership charged third parties.

In March of 2010, the Partnership entered into a second crude oil storage services agreement with Vitol under which the Partnership began providing additional crude oil storage services to Vitol effective May 1, 2010 (the "2010 Vitol Storage Agreement"). The initial term of the 2010 Vitol Storage Agreement is five years commencing on May 1, 2010, subject to automatic renewal periods for successive one year periods until terminated by either party with ninety days prior notice. The 2010 Vitol Storage Agreement was reviewed and approved by the Board's conflicts committee in accordance with the Partnership's procedures for approval of related party transactions and the provisions of the partnership agreement. Service revenues under the 2010 Vitol Storage Agreement are based on the 2.0 million barrels of storage capacity of the crude oil storage tanks that are dedicated to Vitol under the agreement. The Partnership generated revenues under this agreement of approximately $8.1 million, $12.3 million and $11.5 million during the twelve months ended December 31, 2010, 2011 and 2012, respectively. In March 2013, the 2010 Vitol Storage Agreement was amended to adjust the rates the Partnership charges Vitol for services provided under the agreement. The Partnership believes that the rates it charges Vitol under the 2010 Vitol Storage Agreement are fair and reasonable to the Partnership and its unitholders and are comparable with the rates the Partnership charges third parties.

The Partnership entered into two new crude oil storage services agreements with Vitol, the "2012 Vitol 12-month Storage Agreement" and the "2012 Vitol 6-month Storage Agreement", which became effective June 1, 2012, when the 2008 Vitol Storage Agreement expired according to its terms. The Partnership believes that the rates it charges Vitol under both of these agreements are fair and reasonable to the Partnership and its unitholders and are comparable with the rates the Partnership charges third parties. The Board's conflicts committee reviewed and approved each of these agreements in accordance with the Partnership's procedures for approval of related party transactions and the provisions of the partnership agreement.

Service revenues under the 2012 Vitol 12-month Storage Agreement are based on the 1.0 million barrels of storage capacity of the crude oil storage tanks that are dedicated to Vitol under the agreement. The initial term of the Vitol 12-month Storage Agreement is from June 1, 2012 through May 31, 2013. The Partnership generated revenues under this agreement of approximately $3.2 million for the twelve months ended December 31, 2012. In March 2013, the 2012 Vitol 12-month Storage Agreement was amended to extend the term through March 31, 2014 and to adjust the rates the Partnership charges Vitol for services provided under the agreement.

Service revenues under the 2012 Vitol 6-month Storage Agreement are based on the 0.5 million barrels of storage capacity of the crude oil storage tanks that are dedicated to Vitol under the agreement. The initial term of the 2012 Vitol 6-month Storage Agreement was from June 1, 2012 through November 30, 2012. The Partnership generated revenues under this agreement of approximately $1.6 million for the twelve months ended December 31, 2012. Upon expiration of the initial term, this agreement became subject to a rolling 90 day cancellation notice. In March 2013, the 2012 Vitol 6-month Storage Agreement was amended to extend the term through October 31, 2013 and to adjust the rates the Partnership charges Vitol for services provided under the agreement.

During the third quarter of 2012, the Partnership entered into another 6-month storage agreement (the "Vitol September 2012 Storage Agreement") with Vitol effective September 1, 2012. The Partnership believes that the rates it charges Vitol under this agreement are fair and reasonable to the Partnership and its unitholders and are comparable with the rates the Partnership charges third parties. The Board's conflicts committee reviewed and approved this agreement in accordance with the Partnership’s procedures for approval of related party transactions and the provisions of the partnership agreement. Service revenues under the Vitol September 2012 Storage Agreement are based on the 0.5 million barrels of storage capacity of the crude oil storage tanks that are dedicated to Vitol under the agreement. The initial term of the Vitol September 2012 Storage Agreement was from September 1, 2012 to February 28, 2013. The Partnership generated revenues under this agreement of approximately $0.9 million for the twelve months ended December 31, 2012. In March 2013, the Vitol September 2012 Storage Agreement was amended to extend the term through October 31, 2013 and to adjust the rates the Partnership charges Vitol for services provided under the agreement.

Vitol Master Lease Agreement

In July 2010, the Partnership and Vitol entered into a Master Agreement (the "Master Agreement") relating to the lease of certain vehicles by the Partnership from Vitol. Pursuant to the Master Agreement, the Partnership leased certain vehicles, including light duty trucks, tractors, tank trailers and bobtail tank trucks, from Vitol for periods ranging from 36 months to 84 months depending on the type of vehicle. The Partnership had the opportunity to purchase each vehicle at the end of the lease at the estimated residual value of such vehicle. Leases under the Master Agreement were accounted for as operating leases. During the twelve months ended December 31, 2010 and 2011, the Partnership recorded expenses under this agreement of approximately $0.1 million and $0.4 million, respectively. The Master Agreement was approved by the Board's conflicts committee in accordance with the Partnership's procedures for approval of related party transactions and the provisions of its partnership agreement. In September 2011, the Partnership entered into a new master lease agreement with an unrelated third party and terminated the Master Agreement with Vitol.

Vitol Throughput Capacity Agreement

In August 2010, the Partnership and Vitol entered into a Throughput Capacity Agreement (the "ENPS Throughput Agreement"). Pursuant to the ENPS Throughput Agreement, Vitol purchased 100% of the throughput capacity on the Partnership's Eagle North Pipeline System ("ENPS"). The Partnership put ENPS in service in December 2010. In September 2010, Vitol paid the Partnership a prepaid fee equal to $5.5 million and Vitol will pay additional usage fees for every barrel delivered by or on behalf of Vitol on ENPS. This $5.5 million fee received from Vitol is accounted for as a long-term payable to a related party and is reflected as such on the Partnership's consolidated balance sheet as of December 31, 2012. In addition, if the payments made by Vitol in any contract year under the ENPS Throughput Agreement are in the aggregate less than $2.4 million, then Vitol will pay the Partnership a deficiency payment equal to $2.4 million minus the aggregate amount of all payments made by Vitol during such contract year. In March 2012, the Partnership received a deficiency payment of $0.3 million from Vitol in relation to the 2011 contract year. In February 2013, the Partnership received a deficiency payment of $0.2 million from Vitol in relation to the 2012 contract year. The ENPS Throughput Agreement has a term that extends for four years after ENPS is completed and may be extended by mutual agreement of the parties for additional one-year terms. If the capacity on ENPS is unavailable for use by Vitol for more than 60 days, whether consecutive or nonconsecutive, during the term of the ENPS Throughput Agreement, then Vitol shall have the right to terminate the ENPS Throughput Agreement within six months after such lack of capacity. The Partnership has previously contracted to provide throughput services on ENPS to a third party and Vitol's rights to the capacity of ENPS are subordinate to the rights of such third party. In addition, for so long as a default by Vitol relating to payments under the ENPS Throughput Agreement has not occurred and is continuing, the Partnership will remit to Vitol any and all tariffs and deficiency payments received by the Partnership or its affiliates from such third party pursuant to its agreement with the Partnership. The ENPS Throughput Agreement was approved by the Board's conflicts committee in accordance with the Partnership's procedures for approval of related party transactions and the provisions of its partnership agreement.

During the twelve months ended December 31, 2010, 2011 and 2012, the Partnership incurred interest expense under this agreement of approximately $0.2 million, $0.7 million and $0.5 million, respectively. The agreement has an effective annual interest rate of 14.1% and matures on December 31, 2014.

Vitol Operating and Maintenance Agreement

In August 2011, the Partnership and Vitol entered into an operating and maintenance agreement (the "Vitol O&M Agreement") relating to the operation and maintenance of Vitol's crude oil terminal located in Midland, Texas (the "Midland Terminal"). Pursuant to the Vitol O&M Agreement, the Partnership provides certain operating and maintenance services with respect to the Midland Terminal. The term of the Vitol O&M Agreement commenced on

September 1, 2012 and shall continue for five years. During the twelve months ended December 31, 2012, the Partnership generated revenues of $0.2 million under this agreement. The Partnership believes that the rates it charges Vitol under this agreement are fair and reasonable to the Partnership and its unitholders and are comparable with the rates the Partnership charges third parties. The Board’s conflicts committee reviewed and approved this agreement in accordance with the Partnership’s procedures for approval of related party transactions and the provisions of the partnership agreement.

Vitol Shared Services Agreement

In August 2012, the Partnership and Vitol entered into a shared services agreement (the “Vitol Shared Services Agreement”) pursuant to which the Partnership provides Vitol certain strategic assessment, economic evaluation and project design services. The term of the Vitol Shared Services Agreement commenced on August 1, 2012 and shall continue for one year. The Vitol Shared Services Agreement renews annually unless terminated by either party as provided in the agreement.

During the twelve months ended December 31, 2012, the Partnership generated revenues of $0.3 million under this agreement. The Partnership believes that the rates it charges Vitol under this agreement are fair and reasonable to the Partnership and its unitholders. The Board's conflicts committee reviewed and approved this agreement in accordance with the Partnership's procedures for approval of related party transactions and the provisions of the partnership agreement.

Vitol's Commitment under the Partnership's Credit Agreement

Vitol is a lender under the Partnership's current credit agreement and has committed to loan the Partnership $15.0 million pursuant to such agreement. During the twelve months ended December 31, 2010, 2011 and 2012, Vitol received its pro rata portion of the interest payments in connection with being a lender under the credit agreement and received approximately $0.4 million, $0.7 million and $0.7 million, respectively, in connection therewith.

13. LONG-TERM INCENTIVE PLAN

In July 2007, the General Partner adopted the LTIP. The compensation committee of the Board administers the LTIP. The LTIP authorizes the grant of an aggregate of 2.6 million common units deliverable upon vesting. On September 14, 2011, the Partnership's unitholders approved an amendment to the LTIP to increase the number of common units issuable under such plan by 1.35 million common units from 1.25 million common units to 2.6 million common units. Although other types of awards are contemplated under the LTIP, currently outstanding awards include "phantom" units, which convey the right to receive common units upon vesting, and "restricted" units, which are grants of common units restricted until the time of vesting. Certain of the phantom unit awards also include DERs.

Subject to applicable earning criteria, a DER entitles the grantee to a cash payment equal to the cash distribution paid on an outstanding common unit prior to the vesting date of the underlying award. Recipients of restricted units are entitled to receive cash distributions paid on common units during the vesting period which distributions are reflected initially as a reduction of partners' capital. Distributions paid on units which ultimately do not vest are reclassified as compensation expense. Awards granted to date are equity awards and, accordingly, the fair value of the awards as of the grant date is expensed over the vesting period.

In each of December 2010, 2011, and 2012, 7,500 restricted common units were granted which vest in one-third increments over three years. These grants were made in connection with the anniversary of the independent directors joining the Board. The fair value of the restricted units for each of these grants was less than $0.1 million.

In March 2011, 2012, and 2013, grants for 299,900, 353,300 and 353,589 phantom common units, respectively, were made, which vest on January 1, 2014, January 1, 2015 and January 1, 2016, respectively. These grants are equity awards under ASC 718 – Stock Compensation, and, accordingly, the fair value of the awards as of the grant date is expensed over the vesting period. The weighted average grant date fair-value of the awards is $8.25, $6.76 and $8.75 per unit, respectively, which is the closing market price on the grant date of the awards. The value of these award grants was approximately $2.5 million, $2.4 million and $3.1 million, respectively, on their grant date, and the unrecognized estimated compensation cost at December 31, 2012 was $2.3 million, which will be recognized over the remaining vesting period. As of December 31, 2012, the Partnership expects approximately 87% of these awards will vest.

In September 2012, Mr. Mark A. Hurley was granted 500,000 phantom units under the LTIP upon his employment as the Chief Executive Officer of the General Partner. These grants are equity awards under ASC 718 – Stock Compensation, and, accordingly, the fair value of the awards as of the grant date is expensed over the vesting period. These units vest ratably over five years pursuant to the Employee Phantom Unit Agreement between Mr. Hurley and the General Partner and do not include DERs. The weighted average grant date fair value for the units of $5.62 was determined based on the closing market price of the Partnership's common units on the grant date of the award, less the present value of the estimated distributions to be paid to holders of an outstanding common unit prior to the vesting of the underlying award. The value of this award grant was approximately $2.8 million on the grant date, and the unrecognized estimated compensation cost at December 31, 2012 was $2.7 million, and will be expensed over the remaining vesting period.

The Partnership's equity-based incentive compensation expense for the twelve months ended December 31, 2010, 2011 and 2012 was $0.1 million, $0.5 million, and $1.9 million.

Activity pertaining to phantom common units and restricted common unit awards granted under the Plan is as follows:

| | Number of Units | Weighted Average Grant Date Fair Value |
|---|---|---|
| Nonvested at December 31, 2011 | 307,151 | $8.17 |
| Granted | 860,800 | 6.10 |
| Vested | 84,998 | 7.45 |
| Forfeited | 66,250 | 7.56 |
| Nonvested at December 31, 2012 | 1,016,703 | $6.51 |

On October 19, 2011, as part of a litigation settlement, a former member of the Board, Mr. Thomas L. Kivisto, forfeited 150,000 vested but unissued common units related to phantom units awarded under the LTIP in 2007 and 2008. As such, the Partnership recognized a gain of $0.8 million for the twelve months ended December 31, 2011 related to the clawback of the awards and the compensation expense that had been recognized during the vesting period. The gain is reflected as a reduction of general and administrative expenses for the twelve months ended December 31, 2011.

## 14. PROFITS INTEREST OF BLUEKNIGHT GP HOLDING, LLC

In October 2012, the owners of Blueknight GP Holding, LLC ("HoldCo"), the owner of the General Partner, admitted Mr. Hurley as a member of HoldCo. In connection with his admission as a member of HoldCo, Mr. Hurley was issued a non-voting economic interest in HoldCo (the "Profits Interest"). Mr. Hurley's Profits Interest in HoldCo will vest in 20% increments on each of October 4, 2013, 2014, 2015, 2016 and 2017 and entitle Mr. Hurley, to the extent vested, to (i) 2% of the total amount of proceeds and/or distributions in excess of $100,000,000 received by HoldCo in connection with a transaction resulting in a change of control of the Partnership, and (ii) 2% of the portion of any interim quarterly distribution received by HoldCo in excess of $1,250,000. As of December 31, 2012 no Profits Interest is vested.

Although the entire economic burden of the Profits Interest, which is equity classified, is borne solely by HoldCo and does not impact the Partnership's cash or units outstanding, the intent of the Profits Interest is to provide a performance incentive and encourage retention of Mr. Hurley. Therefore, the Partnership recognizes the grant date fair value of the Profits Interest as compensation expense over the service period. The expense is also reflected as a capital contribution and thus, results in a corresponding credit to Partners' Capital in the Partnership's Consolidated Financial Statements. Less than $0.1 million was recognized as expense in 2012.

## 15. EMPLOYEE BENEFIT PLAN

Under the Partnership's 401(k) Plan, which was instituted in 2009, employees who meet specified service requirements may contribute a percentage of their total compensation, up to a specified maximum, to the 401(k) Plan. The Partnership may match each employee's contribution, up to a specified maximum, in full or on a partial basis. The Partnership recognized expense of $1.0 million, $1.3 million and $1.3 million for the twelve months ended December 31, 2010, 2011 and 2012, respectively, for discretionary contributions under the 401(k) Plan.

The Partnership may also make annual lump-sum contributions to the 401(k) Plan irrespective of the employee's contribution match. The Partnership may make a discretionary annual contribution in the form of profit sharing calculated as a percentage of an employee's eligible compensation. This contribution is retirement income under the qualified 401(k) Plan. Annual profit sharing contributions to the 401(k) Plan are submitted to and approved by the Board. The Partnership recognized expense of $0.9 million for each of the twelve months ended December 31, 2011 and 2012 for discretionary profit sharing contributions under the 401(k) Plan. The Partnership recognized no expense for discretionary profit sharing contributions under the 401(k) Plan for 2010.

## 16. COMMITMENTS AND CONTINGENCIES

The Partnership leases certain real property, equipment and operating facilities under various operating and capital leases. It also incurs costs associated with leased land, rights-of-way, permits and regulatory fees, the contracts for which generally extend beyond one year but can be cancelled at any time should they not be required for operations. Future non-cancellable commitments related to these items at December 31, 2012, are summarized below (in thousands):

| | Operating Leases |
|---|---|
| For twelve months ending: | |
| December 31, 2013 | $5,509 |
| December 31, 2014 | 4,580 |
| December 31, 2015 | 3,366 |
| December 31, 2016 | 1,498 |
| December 31, 2017 | 711 |
| Thereafter | 898 |
| Total future minimum lease payments | $16,562 |

Rental expense related to leases was $4.8 million, $5.8 million and $6.5 million for each of the years ended December 31, 2010, 2011 and 2012, respectively.

The Partnership is from time to time subject to various legal actions and claims incidental to its business, including those arising out of environmental-related matters. Management believes that these legal proceedings will not have a material adverse effect on the financial position, results of operations or cash flows of the Partnership. Once management determines that information pertaining to a legal proceeding indicates that it is probable that a liability has been incurred and the amount of such liability can be reasonably estimated, an accrual is established equal to its estimate of the likely exposure.

On October 27, 2008, Keystone Gas Company ("Keystone") filed suit against the Partnership in Oklahoma State District Court in Creek County alleging that it is the rightful owner of certain segments of the Partnership's pipelines and related rights of way, located in Payne and Creek Counties, that the Partnership acquired from SemCorp in connection with the Partnership's initial public offering in 2007. Keystone seeks to quiet title to the specified rights of way and pipelines and seeks damages up to the net profits derived from the disputed pipelines. There has been no determination of the extent of potential damages for the Partnership's use of such pipelines. The Partnership has filed a counterclaim against Keystone alleging that it is wrongfully using a segment of a pipeline that is owned by the Partnership in Payne and Creek Counties. The parties are engaged in discovery. The Partnership intends to vigorously defend these claims. No trial date has been set by the court.

In March and April 2009, nine current or former executives of SemCorp and certain of its affiliates filed wage claims with the Oklahoma Department of Labor against the General Partner. Their claims arise from the General Partner's Long-Term Incentive Plan, Employee Phantom Unit Agreement ("Phantom Unit Agreement"). Most claimants alleged that phantom units previously awarded to them vested upon the change of control that occurred in July 2008. One claimant alleged that his phantom units vested upon his termination. The claimants contended the General Partner's failure to deliver certificates for the phantom units within 60 days after vesting caused them to be damaged, and they sought recovery of approximately $2.0 million in damages and penalties. On April 30, 2009, all of the wage claims were dismissed on jurisdictional grounds by the Department of Labor.

On July 8, 2009, the nine executives filed suit against the General Partner in Tulsa County district court claiming they are entitled to recover the value of phantom units purportedly due them under the Phantom Unit Agreement. The claimants asserted claims against the General Partner for alleged failure to pay wages and breach of contract and sought to recover the alleged value of units in the total amount of approximately $1.3 million, plus additional damages and attorneys' fees. After the suit was filed, the Partnership distributed phantom units to certain of the claimants. On April 14, 2010, a Tulsa County district court judge ruled in favor of seven of the claimants, and awarded them approximately $1.0 million in damages. The Partnership appealed this ruling. On October 22, 2010, the General Partner was ordered to pay $0.2 million in attorneys' fees. The Partnership also appealed this order.

On December 20, 2012, the Oklahoma Court of Civil Appeals issued its opinion on the appeals the Partnership filed. The appellate court determined the phantom unit awards were not wages under the applicable statute, but affirmed the trial court's decision as to a breach of contract of the Phantom Unit Agreement by the General Partnership. The appellate court remanded the case for a hearing to determine the amount of damages and attorneys’ fees to which claimants were entitled based on the breach of contract. The Partnership has filed a petition for rehearing asserting the trial court must take mitigation into account when calculating the breach of contract damages and that a prevailing party attorneys’ fee is not available under the controlling Oklahoma statute. Cross-motions have been filed in the appellate court seeking attorney's fees and costs incurred during the pendency of the appeal. The Oklahoma Court of Civil Appeals has not issued rulings on these motions. While the Partnership believes it has meritorious defenses against the damages and attorneys’ fees sought to be recovered, the ultimate resolution of the matter cannot be determined.

On February 13, 2013, the Partnership filed suit against Koch Industries, Inc. (together with its subsidiaries, “Koch”), a previous owner of the Partnership's asphalt facility located in Northumberland, Pennsylvania. The suit was filed in the United States District Court for the Middle District of Pennsylvania. The Partnership is seeking a declaration that Koch is responsible for any assessment and cleanup costs related to certain environmental liabilities. To date, Koch has not filed an answer to the complaint. Koch has previously taken the position that the Partnership has the responsibility to assess the polychlorinated biphenyl (“PCB”) contamination at such facility although the contamination occurred prior to the Partnership becoming the owner of such facility. The Partnership intends to vigorously pursue the litigation.

On July 11, 2011, ExxonMobil filed suit against the Partnership in Harris County District Court, State of Texas, requesting damages in excess of $35,000 from the Partnership and other, third party service providers in connection with the relocation of existing pipelines of ExxonMobil and the Partnership. The Partnership has filed its answer to the claims and asserted cross-claims against third party service providers including the subcontractors of ExxonMobil. ExxonMobil had previously sent a settlement demand seeking approximately $1.9 million in damages. A trial date was set for February 2013, but the parties have agreed to seek continuance of the trial setting due to the recent joinder of an additional party. The Partnership intends to vigorously defend these claims.

On February 6, 2012, the Partnership filed suit against SemCorp and others in Oklahoma County district court. In the suit, the Partnership is seeking a judgment that SemCorp immediately return approximately 140,000 barrels of crude oil linefill belonging to the Partnership, and the Partnership is seeking judgment in an amount in excess of $75,000 for actual damages, special damages, punitive damages, pre-judgment interest, reasonable attorney’s fees and costs, and such other relief that the Court deems equitable and just. On March 22, 2012, SemCorp filed a motion to dismiss and transfer to Tulsa County. On April 18, 2012, SemCorp filed a motion for summary judgment, and, on May 1, 2012, the district court of Oklahoma County ordered a transfer to Tulsa County. The Partnership is contesting SemCorp’s motion for summary judgment, which has been referred to a special master for report and recommendation. Discovery, before the special master, is ongoing and no trial date is set.

On July 13, 2012, the Partnership and one of its employees were named in a motor vehicle negligence suit in the District Court of Woodward County, Oklahoma, arising out of an accident involving one of the Partnership’s crude oil tanker trucks. The accident resulted in the death of one of the occupants of the other vehicle, and certain unknown injuries to the other occupant. The plaintiff is seeking damages in excess of $75,000 from the Partnership. The Partnership has submitted the claim to its insurance carriers, and the Partnership believes that any recovery would be within applicable policy limits after payment of its $100,000 deductible. Although it is not possible to predict the ultimate outcome of this matter, the Partnership does not expect that an award in this matter will have a material adverse impact on its consolidated results of operations or financial condition.

The Partnership may become the subject of additional private or government actions regarding these matters in the future. Litigation may be time-consuming, expensive and disruptive to normal business operations, and the outcome of litigation is difficult to predict. The defense of these lawsuits may result in the incurrence of significant legal expense, both directly and as the result of the Partnership’s indemnification obligations. The litigation may also divert management’s attention from the Partnership’s operations which may cause its business to suffer. An unfavorable outcome in any of these matters may have a material adverse effect on the Partnership’s business, financial condition, results of operations, cash flows, ability to make distributions to its unitholders, the trading price of the Partnership’s common units and its ability to conduct its business. All or a portion of the defense costs and any amount the Partnership may be required to pay to satisfy a judgment or settlement of these claims may not be covered by insurance.

The Partnership has contractual obligations to perform dismantlement and removal activities in the event that some of its asphalt product and residual fuel oil terminalling and storage assets are abandoned. These obligations include varying levels of activity including completely removing the assets and returning the land to its original state. The Partnership has determined that the settlement dates related to the retirement obligations are indeterminate. The assets with indeterminate settlement dates have been in existence for many years and with regular maintenance will continue to be in service for many years to come. Also, it is not possible to predict when demands for the Partnership's terminalling and storage services will cease, and the Partnership does not believe that such demand will cease for the foreseeable future. Accordingly, the Partnership believes the date when these assets will be abandoned is indeterminate. With no reasonably determinable abandonment date, the Partnership cannot reasonably estimate the fair value of the associated asset retirement obligations. Management believes that if the Partnership's asset retirement obligations were settled in the foreseeable future the potential cash flows that would be required to settle the obligations based on current costs are not material. The Partnership will record asset retirement obligations for these assets in the period in which sufficient information becomes available for it to reasonably determine the settlement dates.

17. ENVIRONMENTAL REMEDIATION

The Partnership maintains insurance of various types with varying levels of coverage that it considers adequate under the circumstances to cover its operations and properties. The insurance policies are subject to deductibles and retention levels that the Partnership considers reasonable and not excessive. Consistent with insurance coverage generally available in the industry, in certain circumstances the Partnership's insurance policies provide limited coverage for losses or liabilities relating to gradual pollution, with broader coverage for sudden and accidental occurrences. Although the Partnership maintains a program designed to prevent and, as applicable, to detect and address such releases promptly, damages and liabilities incurred due to environmental releases from its assets may substantially affect its business.

At December 31, 2011 and 2012, the Partnership was not aware of any existing conditions that may cause it to incur significant expenditures in the future for the remediation of existing contamination. As such, the Partnership has not reflected in the accompanying financial statements any liabilities for environmental obligations to be incurred in the future based on existing contamination. Changes in the Partnership's estimates and assumptions may occur as a result of the passage of time and the occurrence of future events.

18. FAIR VALUE MEASUREMENTS

The Partnership utilizes a three-tier framework for assets and liabilities required to be measured at fair value. In addition, the Partnership uses valuation techniques, such as the market approach (comparable market prices), the income approach (present value of future income or cash flow), and the cost approach (cost to replace the service capacity of an asset or replacement cost) to value these assets and liabilities as appropriate. The Partnership uses an exit price when determining the fair value. The exit price represents amounts that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants.

The Partnership utilizes a three-tier fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value into three broad levels. The following is a brief description of those three levels:

| | |
|---|---|
| Level 1 | Observable inputs such as quoted prices (unadjusted) in active markets for identical assets or liabilities. |
| Level 2 | Inputs other than quoted prices that are observable for these assets or liabilities, either directly or indirectly. These include quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active. |
| Level 3 | Unobservable inputs in which there is little market data, which requires the reporting entity to develop its own assumptions |

This hierarchy requires the use of observable market data, when available, and to minimize the use of unobservable inputs when determining fair value.

The Partnership's recurring financial assets and liabilities subject to fair value measurements and the necessary disclosures are as follows (in thousands):

| | Fair Value Measurements as of December 31, 2010 | | | |
|---|---|---|---|---|
| Description | Total | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) |
| Liabilities: | | | | |
| Fair value of derivative embedded within subordinated convertible debt | $27,550 | — | — | $27,550 |

| | | | | |
|---|---|---|---|---|
| Fair value of rights offering contingency | 10,441 | — | — | 10,441 |
| Total | $37,991 | — | — | $37,991 |

The Partnership had no recurring financial assets or liabilities subject to fair value measurements as of December 31, 2011 or 2012.

The fair value of the embedded derivative within the subordinated convertible debentures was derived using a valuation model and has been classified as Level 3. The valuation model used is a discounted cash flow model (income approach) that assumes future distribution payments by the Partnership and utilizes interest rates and credit spreads for subordinated debt to preferred equity to determine the fair value of the derivative embedded within the subordinated convertible debentures. The change in fair value of the derivative liability from the date of issuance of the subordinated convertible debentures on October 25, 2010 through December 31, 2010 of $6.7 million is included in other expense in the Partnership's consolidated statements of operations. The change in fair value of the derivative liability for the twelve months ended December 31, 2011 of $20.2 million is included in other income in the Partnership's consolidated statements of operations. In connection with the establishment of the conversion price for the Preferred Units following the special meeting of the Partnership's unitholders in September 2011, the number of Preferred Units issuable upon conversion of the subordinated convertible debentures was an amount equal to (i) the sum of the outstanding principal and any accrued and unpaid interest being converted, divided by (ii) 6.50. The establishment of the conversion rate resulted in the embedded derivative meeting the scope exception in ASC 815-15 – Embedded Derivatives, and, therefore, the Partnership reclassified the embedded derivative as partners' capital on September 14, 2011.

The fair value of the rights offering liability related to certain rights that have been offered to common unitholders under the approved Global Transaction Agreement was derived using a valuation model and has been classified as Level 3. The valuation model used is a probability-weighted model (income approach) and assumes the number of rights that are exercised as well as the expected fair value of the Preferred Units at the time such rights are exercised. The change in fair value of the rights offering liability for the twelve months ended December 31, 2010 and 2011 of $4.4 million and $1.9 million, respectively, is included in other income in the Partnership's consolidated statements of operations.

The following table sets forth a reconciliation of changes in the fair value of the Partnership's financial liabilities classified as Level 3 in the fair value hierarchy (in thousands):

| | Measurements Using Significant Unobservable Inputs (Level 3) | |
|---|---|---|
| | For the Twelve Months Ended December 31, 2010 | For the Twelve Months Ended December 31, 2011 |
| Beginning Balance | $35,726 | $37,991 |
| Total gains or losses (realized/unrealized): | | |
| Included in earnings | 2,265 | (22,107) |
| Included in other comprehensive income | — | — |
| Purchases, issuances, and settlements[(1)] | — | (15,884) |
| Transfers in and/or out of Level 3 | — | — |
| Ending Balance | $37,991 | $— |
| The amount of total income for the period included in earnings attributable to the change in unrealized gains for liabilities still held at the reporting date | $(2,265) | $— |

(1) As noted above, the Partnership reclassified the embedded derivative within subordinated convertible debentures to partners' capital as of September 14, 2011.

Fair Value of Other Financial Instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with accounting guidance for financial instruments. The Partnership has determined the estimated fair values by using available market information and valuation methodologies. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

At December 31, 2012, the carrying values on the condensed consolidated balance sheets for cash and cash equivalents (classified as Level 1), accounts receivable and accounts payable approximate their fair value because of their short term nature.

Based on the borrowing rates currently available to the Partnership for credit agreement debt with similar terms and maturities and consideration of the Partnership’s non-performance risk, long-term debt associated with the Partnership’s credit agreement at December 31, 2012 approximates its fair value. The fair value of the Partnership’s long-term debt was calculated using observable inputs (LIBOR for the risk free component) and unobservable company-specific credit spread information. As such, the Partnership considers this debt to be Level 3.

## 19. OPERATING SEGMENTS

The Partnership's operations consist of four operating segments: (i) crude oil terminalling and storage services, (ii) crude oil pipeline services, (iii) crude oil trucking and producer field services, and (iv) asphalt services.

CRUDE OIL TERMINALLING AND STORAGE SERVICES —The Partnership provides crude oil terminalling and storage services at its terminalling and storage facilities located in Oklahoma and Texas.

CRUDE OIL PIPELINE SERVICES —The Partnership owns and operates three pipeline systems, the Mid-Continent system, the Longview system and ENPS, that gather crude oil purchased by its customers and transports it to refiners, to common carrier pipelines for ultimate delivery to refiners or to terminalling and storage facilities owned by the Partnership and others. The Partnership refers to its pipeline system located in Oklahoma and the Texas Panhandle as the Mid-Continent system. It refers to its second pipeline system, which is located in Texas, as the Longview system. The Partnership refers to its third system, originating in Cushing, Oklahoma and terminating in Ardmore, Oklahoma as ENPS.

CRUDE OIL TRUCKING AND PRODUCER FIELD SERVICES — The Partnership uses its owned and leased tanker trucks to gather crude oil for its customers at remote wellhead locations generally not covered by pipeline and gathering systems and to transport the crude oil to aggregation points and storage facilities located along pipeline gathering and transportation systems. Crude oil producer field services consist of a number of producer field services, ranging from gathering condensates from natural gas companies to hauling produced water to disposal wells.

ASPHALT SERVICES —The Partnership provides asphalt product and residual fuel terminalling, storage and blending services at its 44 terminalling and storage facilities located in twenty-two states.

The Partnership's management evaluates performance based upon segment operating margin, which includes revenues from related parties and external customers and operating expenses excluding depreciation and amortization. The non-GAAP measure of operating margin (in the aggregate and by segment) is presented in the following table. The Partnership computes the components of operating margin by using amounts that are determined in accordance with GAAP. A reconciliation of operating margin to income before income taxes, which is its nearest comparable GAAP financial measure, is included in the following table. The Partnership believes that investors benefit from having access to the same financial measures being utilized by management. Operating margin is an important measure of the economic performance of the Partnership's core operations. This measure forms the basis of the Partnership's internal financial reporting and is used by its management in deciding how to allocate capital resources among segments. Income before income taxes, alternatively, includes expense items, such as depreciation and amortization, general and administrative expenses and interest expense, which management does not consider when evaluating the core profitability of the Partnership's operations.

The following table reflects certain financial data for each segment for the periods indicated (in thousands):

| | Crude Oil Terminalling and Storage Services | Crude Oil Pipeline Services | Crude Oil Trucking and Producer Field Services | Asphalt Services | Total |
|---|---|---|---|---|---|
| Year ended December 31, 2010 | | | | | |
| Service revenue | | | | | |
| Third party revenue | $17,701 | $11,740 | $42,437 | $57,205 | $129,083 |
| Related party revenue | 21,258 | 1,543 | 740 | — | 23,541 |
| Total revenue for reportable segments | 38,959 | 13,283 | 43,177 | 57,205 | 152,624 |
| Operating expenses (excluding depreciation and amortization) | 3,491 | 10,205 | 41,585 | 20,985 | 76,266 |
| Operating margin (excluding depreciation and amortization)(1) | 35,468 | 3,078 | 1,592 | 36,220 | 76,358 |
| Additions to long-lived assets | 2,382 | 13,000 | 4,273 | 3,716 | 23,371 |
| Total assets (end of period) | 73,500 | 104,043 | 14,977 | 131,318 | 323,838 |
| | | | | | |
| Year ended December 31, 2011 | | | | | |
| Service revenue | | | | | |
| Third party revenue | $11,067 | $16,984 | $44,366 | $60,201 | $132,618 |
| Related party revenue | 27,608 | 4,807 | 11,561 | 113 | 44,089 |
| Total revenue for reportable segments | 38,675 | 21,791 | 55,927 | 60,314 | 176,707 |
| Operating expenses (excluding depreciation and amortization) | 4,555 | 16,515 | 50,811 | 23,195 | 95,076 |
| Operating margin (excluding depreciation and amortization)(1) | 34,120 | 5,276 | 5,116 | 37,119 | 81,631 |
| Additions to long-lived assets | 5,401 | 6,144 | 1,362 | 6,080 | 18,987 |
| Total assets (end of period) | 69,840 | 99,228 | 15,917 | 119,770 | 304,755 |
| | | | | | |
| Year ended December 31, 2012 | | | | | |
| Service revenue | | | | | |
| Third party revenue | $11,825 | $16,579 | $46,164 | $59,674 | $134,242 |
| Related party revenue | 23,983 | 5,677 | 17,688 | 805 | 48,153 |
| Total revenue for reportable segments | 35,808 | 22,256 | 63,852 | 60,479 | 182,395 |
| Operating expenses (excluding depreciation and amortization) | 3,941 | 18,795 | 56,467 | 23,930 | 103,133 |
| Operating margin (excluding depreciation and amortization)(1) | 31,867 | 3,461 | 7,385 | 36,549 | 79,262 |
| Additions to long-lived assets | 4,611 | 12,396 | 3,451 | 6,260 | 26,718 |
| Total assets (end of period) | 67,051 | 105,498 | 18,646 | 108,630 | 299,825 |

---

(1) The following table reconciles segment operating margin (excluding depreciation and amortization) to income before income taxes (in thousands):

| | Year ended December 31, | | |
|---|---|---|---|
| | 2010 | 2011 | 2012 |
| Operating margin (excluding depreciation and amortization) | $76,358 | $81,631 | $79,262 |
| Depreciation and amortization | 21,447 | 22,775 | 23,129 |
| Loss contingency, net of insurance recoveries | 7,200 | — | — |
| General and administrative expenses | 20,454 | 17,311 | 19,795 |
| Gain on sale of assets | 58 | 3,008 | 7,250 |
| Interest expense | 48,638 | 32,898 | 11,705 |
| Change in fair value of embedded derivative within convertible debt | 6,650 | (20,224) | — |
| Change in fair value of rights offering liability | (4,384) | (1,883) | — |
| Income (loss) before income taxes | $(23,589) | $33,762 | $31,883 |

20. INCOME TAXES

The anticipated after-tax economic benefit of an investment in the Partnership's common units depends largely on the Partnership being treated as a partnership for federal income tax purposes. If less than 90% of the gross income of a publicly traded partnership, such as the Partnership, for any taxable year is "qualifying income" from sources such as the transportation, marketing (other than to end users), or processing of crude oil, natural gas or products thereof, interest, dividends or similar sources, that partnership will be taxable as a corporation under Section 7704 of the Internal Revenue Code for federal income tax purposes for that taxable year and all subsequent years.

If the Partnership were treated as a corporation for federal income tax purposes, then it would pay federal income tax on its income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state income tax at varying rates. Distributions would generally be taxed again to unitholders as corporate distributions and none of the Partnership's income, gains, losses, deductions or credits would flow through to its unitholders. Because a tax would be imposed upon the Partnership as an entity, cash available for distribution to its unitholders would be substantially reduced. Treatment of the Partnership as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to unitholders and thus would likely result in a substantial reduction in the value of the Partnership's common units.

The Partnership has entered into storage contracts and leases with third party customers with respect to substantially all of its asphalt facilities. At the time of entering into such agreements, it was unclear under current tax law as to whether the rental income from the leases, and the fees attributable to certain of the processing services the Partnership provides under certain of the storage contracts, constitute "qualifying income." In the second quarter of 2009, the Partnership submitted a request for a ruling from the IRS that rental income from the leases constitutes "qualifying income." In October 2009, the Partnership received a favorable ruling from the IRS. As part of this ruling, however, the Partnership agreed to transfer, and has transferred, certain of its asphalt processing assets and related fee income to a subsidiary taxed as a corporation. This transfer occurred in the first quarter of 2010. Such subsidiary is required to pay federal income tax on its income at the corporate tax rate, which is currently a maximum of 35%, and will likely pay state (and possibly local) income tax at varying rates. Distributions from this subsidiary will generally be taxed again to unitholders as corporate distributions and none of the income, gains, losses, deductions or credits of this subsidiary will flow through to the Partnership's unitholders.

In relation to the Partnership's taxable subsidiary, the tax effects of temporary differences between the tax basis of assets and liabilities and their financial reporting amounts at December 31, 2012 are presented below (dollars in thousands):

| | |
|---|---|
| Deferred tax assets | |
| Difference in bases of property, plant and equipment | $1,079 |

| | |
|---|---|
| Deferred tax asset | 1,079 |
| Less: valuation allowance | (1,079) |
| Net deferred tax asset | $— |

Given that the Partnership's subsidiary that is taxed as a corporation has a limited earnings history for purposes of determining the likelihood of realizing the benefits of the deferred tax assets, the Partnership has provided a full valuation allowance against its deferred tax asset.

## 21. RECENTLY ISSUED ACCOUNTING STANDARDS

In May 2011, the FASB issued ASU 2011-04, “Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and International Financial Reporting Standards (IFRS),” which provides a consistent definition of fair value and common requirements for measurement of and disclosure about fair value between GAAP and IFRS. This new guidance changes some fair value measurement principles and disclosure requirements. The Partnership adopted this guidance beginning with the Partnership’s Quarterly Report for the period ended March 31, 2012, and the impact was not material.

In September 2011, the FASB issued ASU 2011-08, “Testing for Goodwill Impairment,” which allows an entity to first assess qualitative factors to determine whether it is necessary to perform the two-step quantitative goodwill impairment test. Under these assessments, an entity would not be required to calculate the fair value of a reporting unit unless the entity determines, based on a qualitative assessment, that it is more likely than not that its fair value is less than its carrying amount. The Partnership adopted this guidance beginning in its December 31, 2011 annual impairment test, and the impact was not material.

In July 2012, the FASB issued ASU 2012-02, “Testing Indefinite-Lived Intangible Assets for Impairment,” which allows an entity to first assess qualitative factors to determine whether it is necessary to perform a quantitative impairment test. Under these amendments, an entity would not be required to calculate the fair value of an indefinite-lived intangible asset unless the entity determines, based on qualitative assessment, that it is not more likely than not, the indefinite-lived intangible asset is impaired. The amendments include a number of events and circumstances for an entity to consider in conducting the qualitative assessment. The Partnership adopted this guidance beginning in its December 31, 2012 annual impairment test, and the impact was not material.

## 22. QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized quarterly financial data is as follows (in thousands, except per unit data):

| | First Quarter | Second Quarter | Third Quarter | Fourth Quarter | Total |
|---|---|---|---|---|---|
| 2011: | | | | | |
| Revenues | $41,523 | $43,091 | $46,511 | $45,582 | $176,707 |
| Operating income | 8,301 | 8,819 | 14,215 | 13,218 | 44,553 |
| Net income (loss) | 2,634 | (5,345) | 28,605 | 7,581 | 33,475 |
| Basic and diluted net income (loss) per common unit | (0.39) | (0.55) | 0.38 | (0.05) | (0.61) |
| Basic and diluted net income (loss) per subordinated unit | (0.39) | (0.55) | 0.42 | — | (0.52) |
| 2012: | | | | | |
| Revenues | $44,577 | $43,758 | $47,126 | $46,934 | $182,395 |
| Operating income | 15,141 | 9,117 | 10,931 | 8,399 | 43,588 |
| Net income | 11,994 | 6,147 | 7,907 | 5,517 | 31,565 |
| Basic and diluted net income per common unit | 0.20 | 0.02 | 0.10 | — | 0.32 |

## 23. SUBSEQUENT EVENTS

On February 4, 2013, the Partnership announced that it entered into an agreement with Advantage Pipeline, L.L.C. (“Advantage”) to acquire approximately 30% ownership in a 70 mile crude oil pipeline project running from Pecos, Texas to Crane, Texas. Named the Pecos River Pipeline, the new 16" diameter pipeline will enable west Texas producers to deliver crude oil to Gulf Coast markets through a pipeline connection at Crane, Texas. The Partnership will operate the pipeline under a long term agreement with Advantage.

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